

P. Zylka

Electrochemical gas sensors can supplement chromatography-based DGA

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Abstract Shortening a time gap between oil sampling and its analysis as well as a rapid and correct interpretation of dissolved gas analysis (DGA) results are crucial for effective screening of faulty transformers in predictive-oriented equipment maintenance. Introductory DGA performed quickly by means of a developed portable analyzer, fitted with electrochemical gas sensors, can supplement classical chromatography-based DGA contributing to a correct and rapid transformer fault interpretation. Examples of unusual data mining for sensor-based DGA are also presented.

Keywords Mineral oil · Transformer monitoring · Fault interpretation · Oil thermal breakdown · Partial discharge

1 Introduction

Various designs of oil-insulated power transformers have been put into service since the beginning of the “high voltage” engineering age. Nowadays, thousands of these devices are installed all over the world. Despite the new, oil-free designs that are being introduced, the oil-insulated equipment will be present in power networks for several years to come. Consequently, aging and deterioration processes in oil and paper transformer insulation become serious factors in limiting the safe operation of the power grid.

Energy markets put increasingly strong demands for quality and reliability of uninterrupted power supply.

This has resulted in serious interest and investment in the science and engineering sector of in-service power transformer diagnostics. Various test methods and procedures are in use or at development stage but a common feature of all of them and the key for their reliability is a periodical analysis of the result trends. Dissolved gas analysis (DGA) is one of the diagnostic methods that has proved its effectiveness over several years of industrial practice in preventive- and predictive-oriented maintenance of transformer equipment. Its great advantage is that the DGA test can be performed without the need to power-down the unit being tested. However a classical chromatography-based DGA is difficult to perform in the field and is best run in a laboratory by highly qualified personnel. The classical procedure involves oil sampling at intervals from 6 to over 12 months. Such an approach can result in unforeseen critical faults developing in the intervals between the scheduled tests. Unfortunately, adaptation of the chromatography-based methodology in on-line systems is a costly and error-prone solution. For this reason it is economical to increase the frequency of DGA control checks and hence simultaneously to reduce the cost of a single DGA test. It can be accomplished only by automation of the measurement procedure and fault interpretation schemes as well as by implementing mobile turnkey DGA devices. In order not to limit advantageous features offered by novel gas measuring devices a mobile DGA system does not have to exploit the same principles as in the classical chromatographic approach and give the direct values of gas content, providing that it is able to yield a correct interpretation of gas origin in terms of transformer fault.

To verify the above a portable DGA analyzer was designed and constructed. The main aim of the research work presented in this paper was to validate whether application of electrochemical gas sensors in analysis and monitoring of characteristic gases evolved in transformer faults is possible. The other goal of the research was to find out if such a simplified

P. Zylka
Institute of Electrical Engineering Fundamentals,
Wroclaw University of Technology, Wroclaw, Poland
E-mail: pawel.zylka@pwr.wroc.pl
Tel.: +48-71-3202696
Fax: +48-71-3229725

measurement approach, using gas sensors and non-vacuum gas extraction, can be enhanced by unconventional processing of gas sensor output signals in order to correlate with typical faults observed in power transformers.

2 Apparatus and test objects

2.1 Gas analyzer

A prototype gas-in-oil analysis device ("the analyzer") was designed as a portable and autonomous apparatus, easy to operate in the field. Consequently a reduction of its power supply demand, weight and overall dimensions as well as complicity of operation and service was essential. To attain these goals a choice of electrochemical gas sensors was made. Two such commercially available devices were installed into the analyzer. The sensors were, according to their datasheets, highly selective towards hydrogen and carbon monoxide respectively but they also demonstrated several fairly significant cross-sensitivities. Each sensor was fitted with an electronic potentiostat and a current-to-voltage (I-U) converter, generating an output signal in the 0–2 V range corresponding to a gas-in-air (CO and H₂ respectively) concentration range of 0–2000 ppm.

A process of dynamic gas-from-oil stripping was used to replace vacuum extraction of gases from the oil matrix. A stream of air, used as a carrier, was continuously passed through the oil sample in order to saturate it with the oil-dissolved gases. Air-gas mixture was circulated in a closed loop pneumatic circuit through the oil and gas sensors by means of a small air pump. Measurements of gas sensor output signals were taken every 5 s by the analyzer internal metering circuits and transferred then to a supervising PC for further storage and processing. A single analysis run performed on 25 cm³ of oil took 15 min on average, including automatic purging and cleaning of the analyzer. The prototype device was consuming approx. 6 W during its operation when supplied from 12 V DC source. A more detailed description of the analyzer may be found elsewhere [1].

Gas sensor output waves were used to calculate five parameters characterizing the analyzed oil sample. Two of these parameters, depicted U_1 and U_2 (indices 1 and 2 relate to CO and H₂ sensor respectively), were directly proportional to the sensor output signal in its stable terminal plateau. A quotient of U_1 over U_2 was adopted as the third parameter and depicted k . The last two oil sample descriptors, RT_1 and RT_2 , were computed to describe the transient part of the gas sensor output wave. They are the sensor response time values, which are characteristic for the analyzed oil sample. Relative and therefore dimensionless values of k , RT_1 and RT_2 were used in order to make the descriptors independent on the sensor batch and partially independent of the analysis temperature.

The analyzer response was tested and verified against a laboratory-grade headspace chromatographic unit using gas-in-oil standards prepared with the following pure gases: H₂, CH₄, C₂H₂, C₂H₄, C₃H₆, C₄H₈, C₄H₁₀ and CO.

2.2 Oil samples

In order to have at one's disposal oil samples with reproducible gas content, which would be also representative for common faults observed in in-service transformers, it was decided to simulate insulation defects in a laboratory reduced-scale set-up. The following phenomena have been chosen for simulation: partial discharges (PD) in oil, breakdown of oil channel and thermal oil decomposition.

The above fault processes were imitated in a glass oil-filled chamber containing approx. 5 dm³ of fresh and degassed mineral transformer oil (Mobil Technol2002, provided by Mobil Oil Poland, Warsaw, Poland). The chamber was fitted with an exchangeable electrode system. PDs were generated in a plane-point electrode arrangement for various distances (20–50 mm) and voltages slightly below the breakdown voltage in the given electrode arrangement. In some PD experiments the insulating fluid was also enriched with methane (concentration in oil approx. 1000 ppm) in order to observe collective effects. The same set-up (but with spherical electrodes) was also applied in the oil breakdown simulation. The voltage rise rate was predetermined according to IEC60156 standard [2]. The energy of consecutive breakdowns was kept fairly constant by the high voltage supply current-limiting circuit. Conditions of localized oil thermal decomposition, close to those observed in transformers, were simulated in the chamber by immersion of a small copper-plated resistive heater directly into the oil bath. A hot-spot temperature of the electrically excited heater was monitored by a thermocouple with its junction welded directly to the heater surface. The heater was operated at 180°C (continuously) and 600°C (transient). All experiments were carried out with AC 50 Hz voltage. Artificially deteriorated samples were produced with the oil of low (15 ppm on average) as well as high (40 ppm on average) water content as evaluated by the Karl Fisher titration method [3].

A glass gas-tight syringe was used to sample the oil at constant time intervals or after each breakdown series. The oil was first cooled down and then sampled at a room temperature. The oil chamber was then refilled with the fresh de-aerated insulating fluid and a resultant dilution was taken into account in further calculations. The analyzer performance was also tested with a small number of oil samples acquired from contiguously operated transformers installed in the local power grid. Their gas content, measured by means of a laboratory-grade headspace chromatographic unit, was given in Table 1.

Table 1 Gas content of oils sampled from healthy transformers (in ppm at 20°C)

	H ₂	CH ₄	C ₂ H ₆	C ₂ H ₄	C ₂ H ₂	C ₃ H ₈	C ₃ H ₆	C ₄ H ₁₀	CO	CO ₂
Sample 1	108	56	68	14	29	52	12	14	374	1,253
Sample 2	14	2	1	15	—	2	4	1	309	927
Sample 3	50	6	3	11	54	5	11	1	251	1,251

3 Results and discussion

3.1 Gas sensor cross-sensitivities

Electrochemical gas sensors, although considered to be more selective when compared to solid-state gas sensing devices (e.g. SnO₂-based), are not totally blind for all interfering gases. In case of sensors installed in the discussed analyzer it was found out that they had limited mutual cross-sensitivities (below 15% of the other sensor response) towards their mutual principal gases (i.e. the hydrogen sensor towards CO and vice versa) dissolved in oil. The sensors did not produce any response to dissolved CH₄, C₄H₁₀ and CO₂. Also, the hydrogen sensor did not produce an output signal for C₂H₂ when the carbon monoxide sensor reacted to the gas. The inverted operation was observed for C₂H₄, C₃H₆, and iso-C₄H₈. The carbon monoxide sensor did not react to these gases when a moderate sensitivity was observed for the hydrogen sensor. It was therefore assumed that both sensors do not react to all low-weight alkanes, the carbon monoxide sensor is insensitive to low-weight alkenes and the hydrogen sensor does not react to low molecular weight gases containing a triple C ≡ C bond.

The response time of the sensors was also gas dependent. For H₂ and CO, stable and concentration-independent response time values were measured for sensors 1 and 2 whereas concentration dependency was observed for C₂H₂. The response time for that gas plummeted with rising gas-in-oil quantity. Very long (over 300% if compared to those observed for H₂) response time values were registered when alkene-containing oils were fed into the analyzer.

3.2 Typical and alarm concentration values

In all the simulated fault-related phenomena a linear or near-linear increase of the parameters U_1 and U_2 was observed along with the prolonged time of the fault activity, consistent with the results presented by other researchers [4]. The observed values of U_1 and U_2 were in a broad range—from single to hundreds of mV, depending on the severity of the simulated fault and its activity period. Figure 1 shows exemplary records of gas sensor signals acquired during a prolonged PD activity in oil with low and elevated water content and enriched with methane.

It must be stated that the values U_1 and U_2 are non-unitless and dependent on the corresponding sensor sensitivity towards the main and interfering gases, its

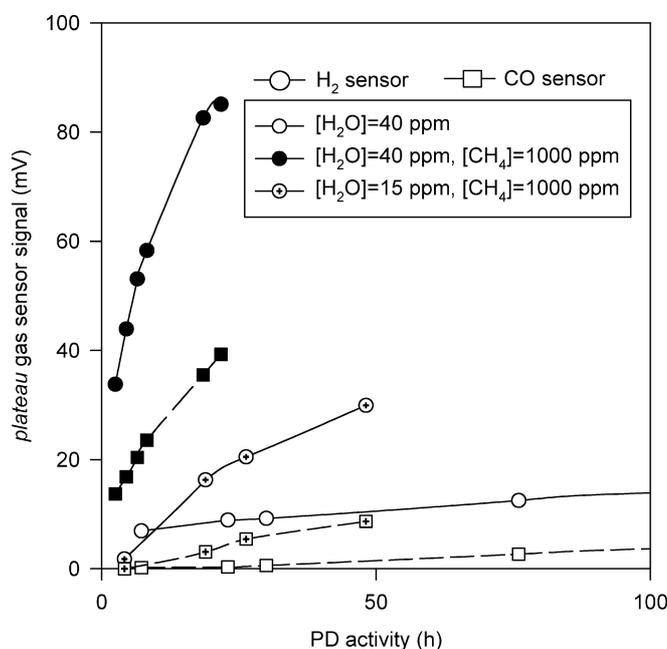


Fig. 1 Gas sensor plateau signals U_1 and U_2 recorded for PD activity in oil with low and elevated water and methane content

I–U conversion factor, the total volume of the pneumatic system installed in the analyzer, the oil sample volume and gas–oil partitioning (Ostwald) coefficients, but in the discussed analyzer design all these factors are constant. Therefore, the concentration of gases measured in the gas phase circulated through the oil may be regarded as proportional to the concentration of gases dissolved in it.

In the classical DGA approach for each analyzed gas there are defined “typical” (as preferred by IEC60599 nomenclature [5]) and alarm values—safe and maximal acceptable concentration of the given gas, which is treated as normal, originating from non-defective transformer operation [6]. Only when the alarm value is exceeded, is the presence of some abnormalities suggested. There is still much uncertainty and controversy regarding the definition of typical and alarm values because they are set arbitrarily on the basis of DGA test records. They are also strongly dependent on the type of equipment, its origin and operation history [7]. The same problem exists for the proposed approach to simplify DGA. The threshold value for the sensor responses U_1 and U_2 cannot be determined from the laboratory tests only, run on artificially generated oil samples, because it is impossible to take into account all the processes active in a real transformer. Any numerical approach is also impossible because of cross-sensitivities of gas sensors

that are hard to account for, their non-linearities, as well as the simulation set-up scaling problems. The only functional approach is to analyze a large number of oil samples taken from transformer units, considered to be healthy and to statistically process the results. A preliminary test, limited in scope to just three transformers (power type, with no communicating OLCT and gas content measured by classical DGA given in Table 1), has been undertaken. Figure 2 presents U_1 and U_2 values characterizing oils sampled from healthy transformers (sample numbers 1, 2 and 3). Analysis of the data gives the likely “typical” values amounting to approx. 30 mV and 20 mV for the CO and H_2 sensor respectively. Figure 2 also shows data gathered for an oil sample (sample number 4) taken from a faulty unit of unknown gas-in-oil content. The transformer unit was identified by a subsequent inspection as suffering from a discharge of high energy with power follow-through.

3.3 Gas sensor response interpretation and fault diagnosing

Values of the sensor plateau signals U_1 and U_2 are thus not remarkably effective for making any direct gas data interpretation apart from the mentioned typical and alarm values, but obviously, as in classical DGA interpretation schemes, the alarm values must be exceeded to proceed to the fault diagnosing stage.

The k , RT_1 and RT_2 values are not selected a priori, just to describe the oil samples in any way. These three parameters, as it will be shown, are a minimal set making possible differentiation between the basic fault

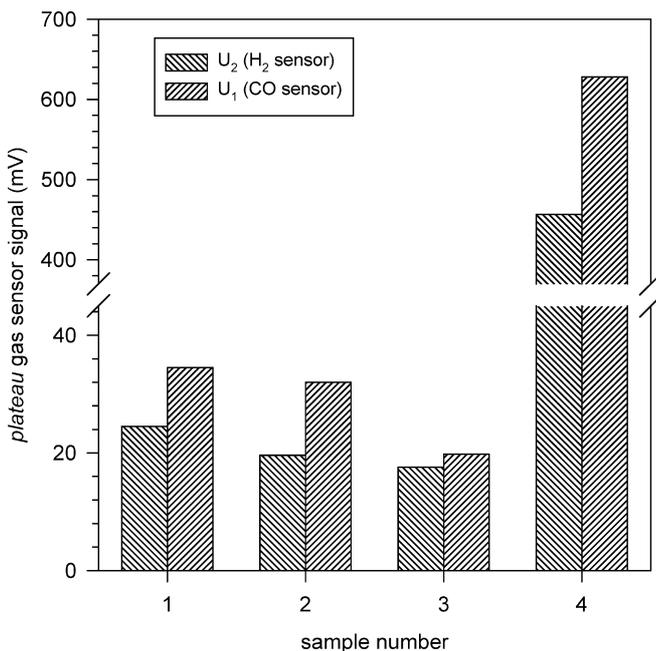


Fig. 2 Gas sensor plateau signals U_1 and U_2 recorded for oils sampled from healthy (1, 2 and 3) and defective (4) transformer units

types. It should be borne in mind that the k parameter is not directly proportional to a quotient $[CO]/[H_2]$ of carbon monoxide and hydrogen concentration in oil. It is because numerical values of U_1 and U_2 are not only purely proportional to the CO and H_2 concentration respectively but also are burdened with some contributions originating from interfering gases.

A three-dimensional (3D) direct graphical illustration of the variation range of these three coefficients is not easy to interpret in terms of correlating with transformer basic faults. Much more unambiguous “fault maps” may be obtained by simply projecting points from such 3D space onto the individual walls of the k - RT_1 - RT_2 coordinate system to construct surface (2D) plots. The projections involving the k axis give the evident distinction between PDs, breakdowns and thermal degradation of the insulating fluid. Figure 3 is an illustration of such a joined map constructed using data gathered from analyses performed using samples of oils deteriorated in laboratory set-ups.

Each basic fault process has its own characteristic and separate region on the 2D fault map in Fig. 3. Moreover, the thermal breakdown territory is divided into two non-overlapping sub-areas. Each of them corresponds to another level of water dissolved in the oil: low and elevated. It is thus possible to distinguish between the thermal breakdown of oil with low and elevated water content working with the data provided by the analyzer. Moreover, this simple observation may lead us to a more important statement. High values of k registered for increased water-in-oil concentration mean that there are large amounts of gases in the oil, which the carbon monoxide gas sensor is sensitive for. It is primarily CO, since the sensor is quite selective towards this volatile and its cross-sensitivity to gases with triple C \equiv C bond may be neglected in this case (those gases

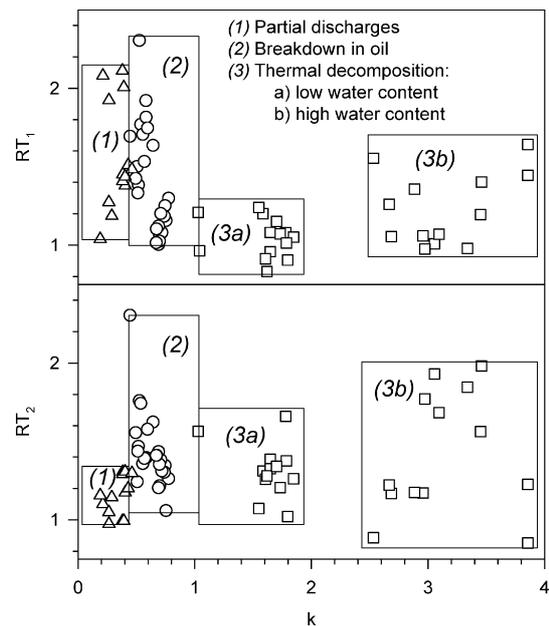


Fig. 3 DGA analyzer: combined fault map

are generally not produced in moderate thermal oil decomposition [8]). DGA interpretation schemes making use of CO_2/CO quotient, e.g. IEC code [5] or the approach recently revised in the CIGRE document [9], are based on the assumption that CO originates only from a breakdown of cellulose products (pressboard, Kraft paper). The results of our experiment suggest that the increased contribution of CO in total gas-in-oil content may originate not only from cellulose solid insulation decomposition but also directly from thermally stimulated interactions between oil and its dissolved water. It is only a speculation now but copper or its compounds may be responsible for catalyzing this hypothetical chemical reaction.

A simple orthogonal RT_1 - RT_2 plane projection does not further enhance the fault diagnosing, since regions of different nature overlap in this case. Nevertheless, supplementary data mining may be performed when we abandon purely Cartesian coordinates and make use of triangular plots, similar to those used in the well-known Duval triangle method [10]. The plots prepared for coefficients k , RT_1 and RT_2 normalized to 1 altogether are shown in Figs. 4 and 5. In order to clarify interpretation of the graphs, data for phenomena different in nature were gathered, separated and illustrated in individual plots, and each will be discussed separately.

The plot shown in Fig. 4 was constructed using data accumulated for samples taken during PD activity in dry, water-enriched and methane-enriched transformer oils. For oils with increased water content only we observe PD characteristic points in the lower-left part of the triangular plot with higher RT_1 quota. Methane presence in the oil, almost independently of water concentration level, is indicated by a characteristic shift towards lower RT_1 and higher RT_2 shares. The k value is only slightly affected in this case. The methane-related

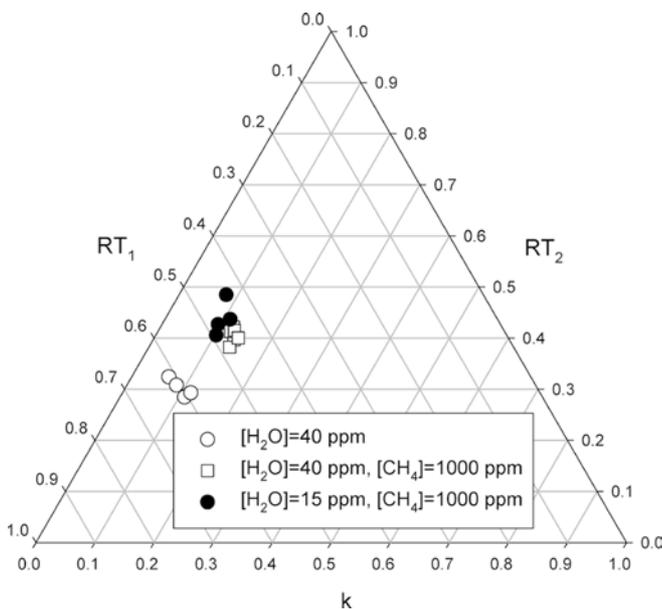


Fig. 4 DGA analyzer: triangular fault map for PDs

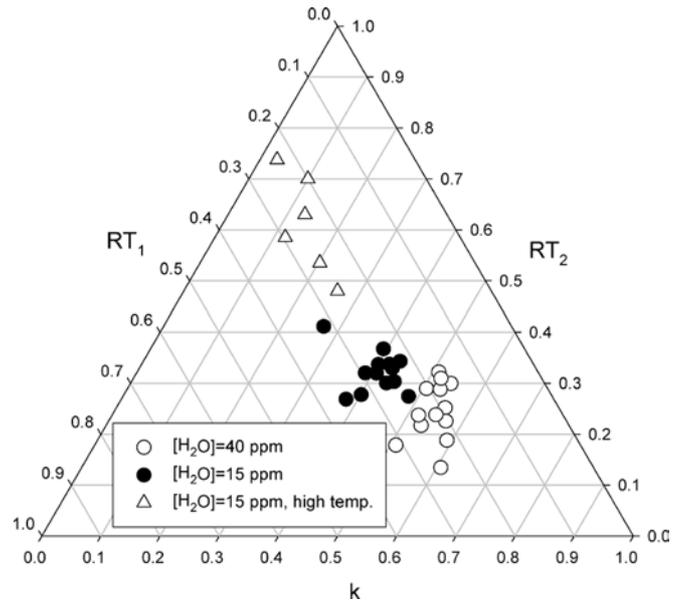
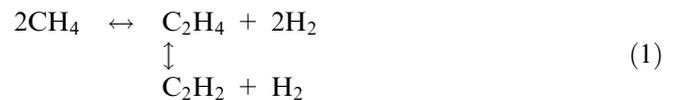


Fig. 5 DGA analyzer: triangular fault map for thermal oil decomposition

shift may be accounted for when we take into consideration the following reaction chain:



Reaction 1, driven by the energy provided by the PDs, may be identified as responsible for converting CH_4 into C_2H_2 with H_2 as a by-product [11]. A basic theoretical calculation based on 1 gives the concentration ratio of its final product as 1:3 ($\text{C}_2\text{H}_2:\text{H}_2$). A close fit in k coefficient is observed when we take into account a cross-sensitivity of the CO sensor to acetylene. It suitably supports the thesis on possible conversion of oil-dissolved methane into acetylene during PD action in oil. As a consequence of this statement such an effect of methane to acetylene conversion may be also observed in faulty transformers, where PDs are generated as a side-fault to hot spots, which are responsible for production of elevated amounts of methane owing to the thermal cracking of the oil [8, 12]. It should be noted that for combined faults most of the classical DGA interpretation strategies give erroneous warnings misjudging the fault type and its origin. Our results reveal that C_2H_2 presence in transformer oil samples does not necessarily have to be related to violent fault events such as arc discharge with intense energy transfer.

A triangular plot may also provide certain information on the characteristic temperature of the fault in case of pure thermal oil decomposition. Figure 5 gives an illustrative insight into this problem. Increase of the hot-spot temperature responsible for thermal oil degradation is accompanied by an almost linear shift towards minor k and high RT_2 quota along RT_1 lines. The values of RT_1 are almost unaffected by the fault temperature

variations in range up to at least 600°C because the carbon monoxide sensor is insensitive to the interfering gases appearing in the cracked oil (mainly alkenes with traces of C₂H₂ only [13]). High RT_2 values, observed in case of increased temperature, are related to the cross-sensitivity and relatively long response time of the hydrogen gas sensor exhibited towards gaseous hydrocarbons with double C=C bonds. Those mild chemically active gases are produced in serious amounts in high-temperature oil decomposition [11].

The k descriptor (which, because of the cross-sensitivity of the sensors, is not purely the ratio of [CO]/[H₂] gases), may be thus regarded as significant not only for PD-related incipient faults. It is also possible to discuss transformer fault detection without detailed data on C₂H₂ measurements, despite it being a key gas for different medium- and high-temperature faults (which are the most frequent incipient faults discovered by classical DGA in transformers). As shown, even without a precisely measured C₂H₂ gas concentration we can see the difference between PDs and discharges.

4 Conclusion

The results presented so far let us state that electrochemical gas sensors are applicable to perform simple analyses of gases dissolved in transformer oil. A correct set of parameters calculated from just two sensor response signals is sufficient for an identification of basic thermal- and electrical-in-origin transformer faults. Moreover, such diagnosis, although seriously limited in scope, may be performed almost instantaneously after oil sampling on site. The proposed method of rapid introductory DGA may effectively supplement the classical DGA procedure in every-day transformer maintenance practice. Although it cannot compete with the sensitivity and selectivity of classical chromatographic measurements, the method could in some instances save on expenditure when a faulty transformer unit is not diagnosed on time.

The phenomena related to a role played by water in transformer oil decomposition with gaseous products as well as problems of coexistent faults of a different nature

have not been sufficiently dealt with in the relevant literature so far. It seems that classical chromatography DGA results may not be so easy to interpret when these aspects are concerned, whereas some results furnished by electrochemical gas sensors (remarkably because of their non-selectivity and thus in some way their built-in data generalization and classification) may provide a valuable insight into these types of transformer-related problems.

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