Hydrogen – the most measured and monitored transformer parameter

Relevance of a 100-year maintenance paradigm in the 21st century

ABSTRACT

Hydrogen gas has been the most measured transformer parameter in the last 30 years. At least 95 % of all online monitors used for continuous monitoring of transformers measure hydrogen. The majority of online monitoring performed on transformers measure only hydrogen, or the composition of gases as one figure relative to hydrogen. Subsequently, the data obtained for these single dissolved gasses is huge compared to any other measurement for transformer maintenance. The hydrogen concentration value seems to be the greatest contributor to making what is the most important decision for transformers worldwide – determining the transformer condition.

While my previous columns looked at a big picture of transformer maintenance through oil analysis, this article will scrutinize a very small element; in fact, the smallest molecule measured inside the transformer. The article will review historical facts related to hydrogen-based maintenance as well as modern approaches to hydrogen detection, measurement and especially diagnosis. Based on all these evidence, it is probably the right time to consider monitoring other dissolved gases in order to obtain an improved diagnosis. Future gas monitors will need to have less false alarms and greater rate of success in predicting fault condition and prolonging the transformer life.

KEYWORDS

dissolved gas analysis, hydrogen, maintenance

Hydrogen, as the smallest molecule inside the transformer, has been the most measured parameter in the last 30 years

1. Introduction

Transformers have been used for more than 130 years. For most of that time, over 120 years or so, transformer cooling oil has been the most popular choice for insulating and cooling the transformer, and since those early days of their operation, the engineers, mostly electrical engineers, have been trying to measure as many available parameters as possible based on the knowledge and possibilities available in each time period. The first such measurements were performed at the beginning of the 20th century. Probably the first measurements were the breakdown voltage or the capabilities of the insulating oil to support an increasing DV voltage applied between various tips. As soon as the knowledge and the technology became available, engineers started to perform most of the tests we perform today, such as oxidation stability, moisture and acidity, and they even started estimating the gasses produced in the insulating oil at different stresses.

2. History of gas in oil measurements

The first observation in transformer history that correlates faulty condition to evolved gasses from the mineral oil is documented in a paper from 1919 [1]. This is probably the first paper where hydrogen (H_2) was mentioned as the most distinctive indicator of electrical discharge in the oil – the famous D2 fault type, as we call it today.

The next major development in transformer monitoring was the genius invention of the Buchholz relay in 1921. This protecting device is still mounted in probably all oil-filled transformers with the conservator in the world, based on the same principles laid by Max Buchholz almost 100 years ago. The great qualities of the Buchholz relay, its reliability and contribution to transformer performance make it the most important protective transformer device. The malfunctions and limitations of the Buchholz relay were extensively described by P. Ramachandran [2].

Although this was probably not considered by its inventor, one of the most important aspects of the Buchholz relay is the possibility to analyse the gas that accumulates in the relay. The gases that develop following a fault in a transformer accumulate in the relay and cause the transformer to trip. In most cases, the cause of the sudden failure was arcing, which, as we know today, contains mainly acetylene and hydrogen. From the beginning engineers correlated the nature of gases to the type of failure.

The first detection method for measuring and diagnosing the gas composition was of course by lighting the flame with a match.

Most engineers remember the old days when the Buchholz alarm was checked in a very simple way by letting the gases exhaust the pipe and then lighting the flame. The diagnostic was rather rough and simple, but very quick; and not safe of course. Considering that not all combustion gases are fault-related gases, even when present in unusual amounts, it was possible to miss a real failure. Excessive overloading mainly produces methane and ethane at relatively low temperatures. If the oil is not degassed, saturation is easily achieved, and the reality is that due to combustion gases the Buchholz will switch off the transformer. In cases when it is not possible to identify gases, the only choice is to remove the transformer from service. The field experience has shown that overloading a healthy transformer does not affect its routine operation. So, if the combustion gases do not contain acetylene, the transformer can be safely energized, needing frequent DGA testing afterwards.

In the 1940s identification of gases in gas cushion started [3]. Since significant amounts of gases are mainly caused by arcing, the identified gases were

The first paper that mentions hydrogen as the most distinctive indicator of electrical discharge in the oil – the famous D2 fault type – dates back to 1919

Figure 1. Ampules for sampling gas and oil, the U.S. and European versions

Figure 2. Sampling in duplicate helps reveal incorrect sampling

Figure 3. Special sealing between the piston and glass body made to avoid hydrogen escaping from the syringe

Even non-leaking syringes of gas-in-oil standards have a 2 % loss rate of hydrogen per day

Figure 4. Head Space carousel and the oven for shaking and heating the vials containing the oil sample

predominately acetylene and hydrogen. The sampling was performed in a metal tube in the U.S. or a glass tube in Europe.

Between the 1950s and 1970s, the mainly used detecting methods of gases were IR and Mass Spectra, Sloat 1967 [4] and Vora & Aicher 1965 [5]. In the late 1960s and from the 1970s onwards, the most used procedures to perform DGA included sampling by syringes, extracting by vacuum extraction [6] and detecting by Gas Chromatography (GC). Until the 1980s, Mass Spectra was a real competition to GC [7]. Due to the skills required to use syringes, many transformers were traditionally sampled by using ampules. Other inexperienced sampling teams adopted oil sampling procedures using metal or bottle cans. All these sampling vessels were approved by ASTM and IEC standards. But without doubt, the most accurate sampling method, especially for low concentrations of the lightest gas of all – hydrogen, is to carefully sample the insulating oil using syringes.

Even non-leaking syringes of gas-in-oil standards have a 2 % loss of hydrogen per day. If the syringe is leaking due to impurities or air transport stresses, then the uncertainty of hydrogen can be higher than 30 % for the normal interval between sampling and testing. It can be noted that for Morgan Schaffer's gas-in-oil standards, the concentration is guaranteed for one month only, even though they are specially sealed between the piston and glass body, Fig. 3.

The bubble in a syringe, or in any other type of bottle, attracts and extract mainly the hydrogen gas due to its lower solubility compared to other gases.
Tenbohlen et al. [8] showed that the concentration of hydrogen decreases up to 30 % in two weeks if the bubble is

small. The value depends on the size of the bubble, and the vibration of the syringe between sampling and measuring.

The most used method in the laboratory at present time is Head Space, followed by Sensitive Gas Chromatography, Fig. 4. However, this technique is rather inaccurate for hydrogen measurement due to the following reasons:

- One of the most influential factors for hydrogen evaluation is that the gas bubbles from the oil are not transferred to the extraction system as was a case with the old mercury partial or totally degasses with Torricelli or Toppler pump. The existent standards IEC60567 and ASTM D3612 mention these differences between mercury vacuum extraction methods and Head Space. Also, using the available vacuum degassing by the non-mercury method does not allow introducing the bubble inside the extraction and measuring unit.

- After transferring the oil from the syringe to the punched vial, according to ASTM and IEC, the hydrogen may escape through the punched septa. The loss of hydrogen may be up to 30 %, also depending on the needle diameter, septa quality, and the type of oil in the vial. The time between the vial filling and the automatic injection into the port of the gas chromatograph may be longer than 30 hours due to the large amount of vials in racks of new models.

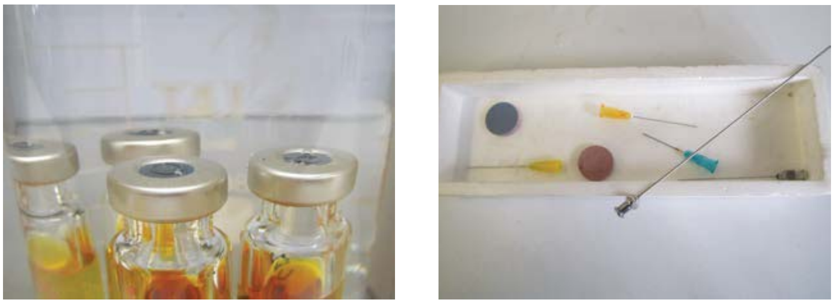

Figure 5. Leaking punched vial immersed in water (left); different needle sizes for punching different kinds of septa (right)

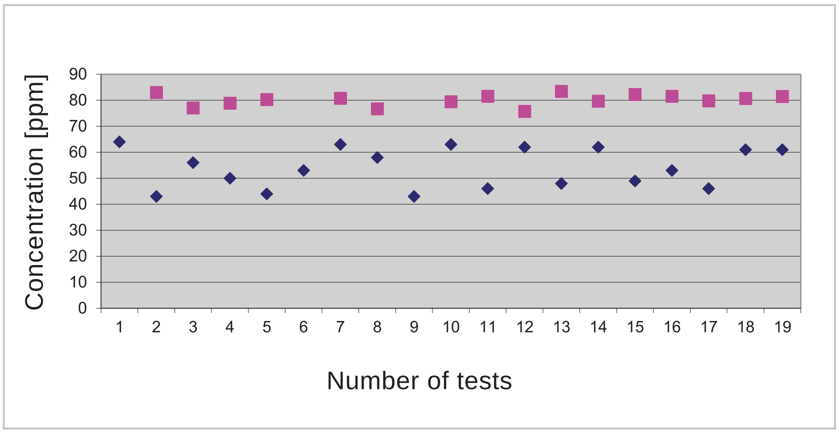

Figure 6. Measured accuracy of hydrogen by PAS (pink dots) and GC (purple dots). The measurement was performed with a gas in oil standard of 80 ppm, with an old version of PAS device

Users have to be very careful when considering any diagnosis based on hydrogen values that have been obtained by PAS devices

For Gas Chromatography Head Space, according to ASTM D3612 the uncertainty for punched vials is between 22 % and 40 %. For non-punched vials, according to IEC60567 the uncertainty is between 15 % and 30 %.

Non-chromatographic DGA was introduced in 2003 by implementing photoacoustic spectroscopy (PAS) in the portable or online device [9]. In the early years, the PAS sensor was manufactured only by one company, Kelman, but today there are at least four manufacturers of these portable and online devices.

Although most studies have found that the accuracy of PAS is acceptable for most of the gases, one study showed a 40 % difference between the hydrogen concentration when measured by PAS method and when measured in the laboratory [10]. Also, Cigre report 409 [11] displays the same magnitude of inaccuracy for this measurement, 38 %, recorded by seven utilities, see Table 8 in [11]. Since hydrogen cannot be detected by PAS, for some version of instruments this measurement is not accurate and repeatable. So, the users have to be very careful when taking into consideration any diagnosis based on hydrogen values obtained by PAS devices, Fig. 6.

3. Online monitors

Most DGA measurements today are performed either by the fuel cell online monitors or in the laboratories. The fuel cell

Table 1. 90th percentile for the fleet with non-free breathing transformers designed and manufactured in the last 25 years

Calculated 90 % of the Hydran value	C_2H_2	CH_4	C_2H_6	C_2H_4	CO	CO_2	H_2	TG %
170-300	0.5-3	80-200	40-120	70-160	950-1200	5500-6500	20-70	3.0-5.5

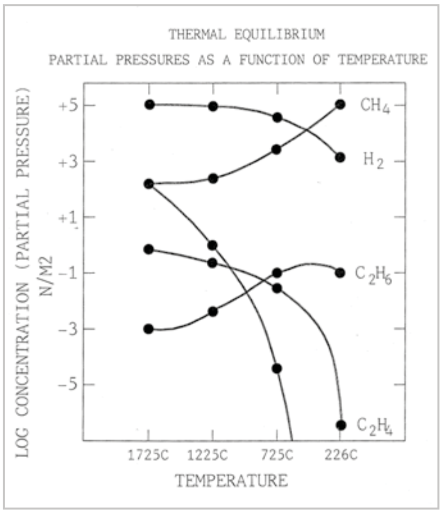

Figure 7. Thermodynamics of gases vs. temperature (IEEEC57.104- 2008), based on previous research by Halstead in 1973

device is the oldest and the most popular device for DGA measurements.

Today there are more than 50,000 online devices in the world installed over the last 30 years, according to the data from GE [12]. These instruments record at least three data sets per day, and they have produced at least one-third of the existent DGA data in all databases in the world today.

The fuel cell device developed in 1977 by M. Duval et al. [13] is of course accurate if one calculates the displayed values according to the declared sensitivity. Data from different fleets with more than 2,500 transformers and more than 200 different installed online monitoring devices shows a measurements accuracy of 25 % according to the Cigre brochure 409 [11]. The main problem occurring in recent years is the increasing discrepancy between the hydrogen value and display values which are considered to represent the dissolved hydrogen concentration in oil. The hydrogen gas has a declared sensitivity of 100 %, while the second most sensitive gas is carbon monoxide with approximately 18 % sensitivity. This can be especially noticed in transformers of newer design, according to the latest observations [13].

As can be observed in Table 1, 90th percentile from the observed fleet are specified by the following characteristics: non-free breathing transformers, with total dissolved gas lower than 5 %, and operating with elevated ambient and internal temperatures, while the values of carbon monoxide behave as expected.

Table 2. Transformer fault type probability classified by [16]

Type of fault	No. of faults	Ratio %
Overheating	226	53.0
High energy discharging	65	18.1
Overheating and high energy discharging	36	10.0
Spark discharging	25	7.0
Dumping or partial discharging	7	1.9

The industry needs diagnostic algorithms which are based only on reliable measurements obtained from a device with a proved medium and long-term stability

For the record, it has to be mentioned that all Furan measurements are lower than 0.1 ppm, without any other evidence for cellulose destruction. In this situation, the error for the fuel type device in comparison to the real hydrogen value is found to be higher than 100 %.

Some of the new online devices for selective hydrogen lead to improper sampling because the oil flows from the main tank to the sensor. Without a forced or directed flow, the value measured is not representative. The main advantages of fuel cell-type monitors over new hydrogen-type online gas monitors are the long-term stability, reliability and experience of the industry. As was a case in the past, some of the new online devices will disappear in the future. This is possible considering that approximately a third of the brand names mentioned in Table 1 of the CIGRE brochure 409 [11], which is dated 2010, are already unavailable in 2018.

The transformer users and especially the algorithm and health index developers have to be aware of all those possibilities and build algorithms based only on reliable measurements obtained from a device with proved medium and long-term stability.

4. Diagnosis based on dissolved hydrogen concentration

In addition to sampling uncertainties by online and offline measurements, and relatively elevated uncertainties of hydrogen measurement by most popular available instruments, the interpretation of results also has a substantial contri-

Table 3. Fault type classification by key gas method [17]

Fault type	Relative proportion of gases %					
	H_2	CH_2	C_2H_2	C_2H_4	C_2H_6	CO
Overheating in the oil	2 %	16 %	/	63 %	19 %	/
Overheating cellulose	/	/	/	/	/	92 %
Partial discharge	85 %	13 %	/	1 %	1 %	/
Arcing	60 %	5 %	30 %	3 %	2 %	/

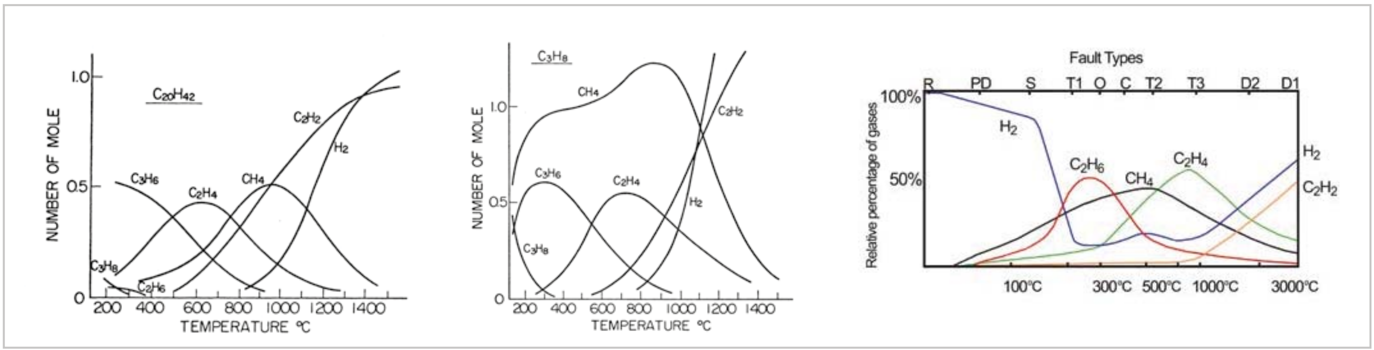

Figure 8. Thermodynamics of gases vs. temperature: comparison of theoretical diagrams by M. Shirai et al. [14] (left and centre), and actual and most recent scheme by M. Duval [15] (right)

bution to the overall (un)certainty of the diagnosis based on the concentration of dissolved hydrogen. It seems that hydrogen concentrations could be problematic, and one of the main concerns is that the liquid and solid insulation existing in the 1970s when most of the diagnostics was developed is not the same as what we have today.

The most significant differences in thermodynamics of gases vs. temperature are illustrated in Figure 7 and Figure 8.

In the past, hydrogen was attributed to thermal issues or partial discharge issues. Based on this, many online device manufacturers claim, even today, that the majority of faulty conditions are characterized by appearance of hydrogen in significant amounts. However, a more recent study observes that in a big majority of failures, hydrogen is not an important gas. Most of the failures are overheating or thermal-type failure – 53 % of them [16], and the gas appearing in overheating is ethylene, while hydrogen comes only at 2 % [17].

In a fleet of more than 200 monitored transformers, in 70 % of the cases where faulty condition was discovered by DGA, there was not a significant concentration of hydrogen. In the rest of the cases where there was a significant hydrogen concentration, other hydrocarbons or carbon oxides were also present in such concentrations that they allowed predicting the failure. However, in at least five cases, the hydrogen development was confirmed as stray gas, and the hydrogen alarm and trigger was indeed a false alarm. Stray gassing produces high concentration of gases, which leads to a false alarm. So, stray gassing is a very tricky issue in diagnostics. Not all transformers filled with potentially stray gassing oil actually develop stray gassing.

Figures 9, 10 and 11 illustrate some of the issues related to diagnosing a failure based on hydrogen.

Figure 11 depicts a real PD fault – an internal failure that occured after eight years of continuous monitoring by offline and online devices, with a high but fluctuated concentration of hydrogen, between 500 and 1200 ppm. The failure occurred at 800 ppm hydrogen and 55 ppm methane, but the recorded fluctuation of the concentration made it difficult to decide if the fault was active or not. Finally, the fault was detected on the basis of ethylene, and not on the basis of abnormal hydrogen value.

According to different studies, the most popular and successful diagnostic method, the classic Duval Triangle [18], is able to reveal the fault in more than 90 % of cases if applied correctly, and it achieves these performances without using hydrogen. It seems that the undisputable success of this method lies in the fact that it is not affected by the uncertainty of hydrogen evaluation. The used hydrocarbons are much less sensitive to usual stray gassing.

F. Jacob and J. Dukarm [19] recommend not to take into consideration hydrogen and carbon monoxide concentration values for fault evaluation. More and more experts warn about problematic interpretation of those gases. In a recent study [20] it was established that most of the available diagnosing methods suffer from inaccuracy due to stray gassing, which is at

A recent study observes that in a big majority of failures, hydrogen is not a significant gas

Table 4. Characteristic gases for particular abnormal conditions [16]

Main gases	Abnormal conditions	Abnormal conditions
H_2	Partial discharge, arc discharge	Short circuit between winding layers, winding breakdown; partial discharge between the tap-changer contacts, arc discharge, short circuit
CH_4, C_2H_2	Overheating, loose contact	Loose contact of tap-changer, joint becoming loose, insulation is poor
C_2H_2	Arc discharge	Winding short circuit, flashover between the tap-changer contacts

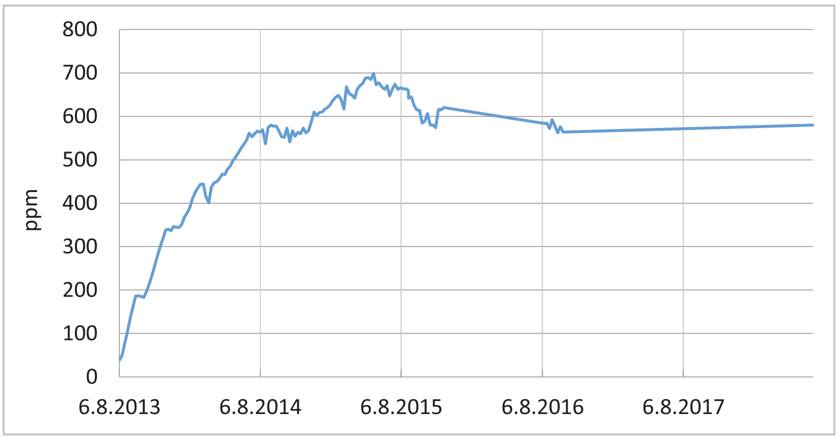

Figure 9. Stray gassing phenomena in an oil-filled GSU transformer, manufactured in the last five years

It seems that the success of Duval Triangle lies also in the fact that it is not affected by the uncertainty of hydrogen evaluation

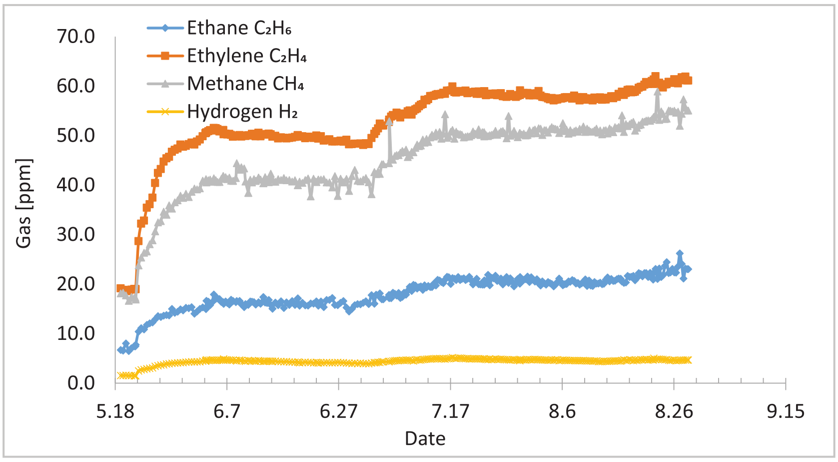

Figure 10. Online multi-gas monitor detected a metal hotspot on the connection bolt, without an increase of hydrogen concentration

Figure 11. A case of internal failure occurring at gas concentrations of 800 ppm hydrogen and 55 ppm methane

least 34 % for Duval Pentagon and much higher for others.

Among other chemical parameters which are worth monitoring are:

- Ethylene – present in all faulty thermal conditions and less susceptible to stray gassing
- Oxygen – probably the most important gas dissolved in oil for all non-breathing transformers, especially those filled with natural ester. Oxygen is the best indicator of oil ageing, and of course, the integrity of the sealing system. Its importance was observed a long time ago [21], and the technology to monitor the dissolved oxygen concentration correctly is now available. Also, in case of transformer fire due to external reasons such as the bushing ignition, degassed oil with low oxygen is less susceptible for fire.

Conclusion

In the early days of DGA, the most measured gases were hydrogen, carbon monoxide and acetylene. These gases were present in a gas cushion above the oil or the protective relays, in connection to electrical discharge that mostly involved cellulose. The early measurements were performed with low sensitive devices, as early IR and Mass Spectra. It is time for a rethink about the necessity and advantages of monitoring hydrogen alone or with carbon monoxide and their relevance to obtaining a reliable health index. In the 21st century, the technology allows developing new detectors, even based on old MS principles or on new inventions. The elevated inaccuracies of low concentration measurements of dissolved hydrogen, together with still unexplainable phenomenon of stray gassing, impose an additional concern about using hydrogen and, to a lesser degree, carbon dioxide parameters for transformer diagnosis.

It is reasonable to gradually diminish the hydrogen role in transformer maintenance.

DISCLAIMER: Marius Grisaru contributed to this article in his personal capacity. The views and opinions expressed in this article are those of the author only and do not reflect the policy or position of Israel Electric.

Table 5. Inaccuracies in transformer diagnosis by hydrogen solely

Offline DGA	Sampling	Extraction	Measurement	Diagnosis	Overall inaccuracy
Minimum inaccuracy	10 %	15 %	10 %	30 %	Greater than 500 %
Maximum inaccuracy	50 %	40 %	60 %	70 %	Greater than 5000 %

Online DGA	Measurement	Diagnosis	Overall inaccuracy
Minimum inaccuracy	20 %	30 %	Greater than 500 %
Maximum inaccuracy	70 %	70 %	Greater than 5000 %

It is time for a rethink about monitoring hydrogen and carbon monoxide, and their relevance to obtaining a reliable diagnosis

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