Analysis of Gases Dissolved in Electrical Insulating Fluids, Technologies and the Importance of Accuracy.

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***Abstract*— Analysis of dissolved gases (DGA) and water in electrical insulating fluids allows electrical equipment operators to monitor for the presence or absence of a variety of faults as well as to observe normal or accelerated asset ageing. DGA may be accomplished by direct wet measurement in the oil or by analysis of gases extracted from the insulating fluid. Direct measurement of some target compounds such as hydrogen or water can be performed by various immersed solid-state sensors. Gas extraction in combination with chromatographic, spectroscopic, and solid-state sensor measurements in the gas phase is widely applied for more detailed analyses of multiple gases. Standards promulgated by ASTM, IEEE, and IEC present various methods of extraction and interpretation of substances dissolved in insulating oil. This paper reviews the background, the importance of accuracy to successful diagnosis and present state of DGA methods and technologies.**

I. INTRODUCTION

Electrical transformers are well known for their robust construction with relatively few assembly components, most of which are highly reliable. However, replacement costs upon failure are very high, and loss of revenue from ensuing failures is also large. The time required to replace these assets can be lengthy, and the collateral damage can be huge. At a time when the industry is losing its deep subject-matter expertise on transformers and related assets, automation of transformer condition assessment has become an attractive option.

Even before the notion of condition assessment, it was well understood that transformers were key to delivering reliable, safe and affordable electricity and that proper monitoring and maintenance would be required during their entire lifetime. Initially, the focus was more on operational issues as opposed to understanding the condition of the asset, and most large transformers would carry a number of sensors that measured fundamentals such as temperature, load, and voltage, as well as cooling status and so on. One of the early tests carried out to ascertain transformer condition was dissolved gas analysis (DGA). DGA was used initially in the late 1920s and was introduced into routine transformer assessment in the late 1960s by pioneers such as Dr. James Morgan, who worked with Hydro Québec researchers and with laboratories such Doble Engineering. DGA has since become a defacto standard as it can provide a wealth of information about the asset and its possibility of failure.

It is difficult to pinpoint the exact number of large power transformers with ratings of 115KV / 100MVA and higher globally. Based on an assumption that the US holds approximately 20% of the global installed base and incorporates about 30,000 units today it could be projected that 150,000 is an appropriate estimation for the global population. Of these, up to 70% are older than 30 years, and the average age of the largest assets may approach 40 year or more, i.e. a very large number are at or near the end of their design life. Operators of these assets face substantial replacement costs as these transformers age out. Optimally predicting end-of-life and managing which will be replaced or refurbished is a complex ongoing task that can be made more effective by the application of appropriate diagnostic tests, including DGA.

II. WHAT IS DGA?

Mineral oil is the most commonly used transformer dielectric fluid, acting as both a cooling medium and an additional element of the electrical insulation system in the transformer. Gases are formed in the oil and the cellulose based structural members of the transformer by normal and abnormal thermal, electrical, and chemical conditions. Analysis of the volume, type, proportions, and rates of gas production yields a substantial amount of diagnostic information about the nature and future trends of normal ageing and abnormal internal faults. Transformer insulation and oil will degrade faster under incipient fault conditions, and will do so in ways that are characteristic of the type of fault or faults at hand. For this reason it is important to test oil samples regularly to ensure that degradation has not gone too far. The normal, non-faulting degradation rate depends on a number of factors such as transformer age, water content, operating temperature, amounts and types of contaminants, and the amount of oxygen in the oil. How regularly these tests should be conducted will depend on whether any known fault condition exists in the asset, the critical nature and size of the transformer, and whether any known problems exist with a particular family of transformer designs.

A thorough discussion of the relationships between fault gases and fault types is beyond the scope of this paper – and is in fact still developing through the work of many individuals and organizations. Several diagnostic tools that utilize gassing levels, ratios, and trends have been in use for many years. Notably, Michel Duval ( ) recently proposed a

pentagonal graphic that depicts the relationships between fault gas formation and type of fault for five key fault gases, as shown in Figure 1.

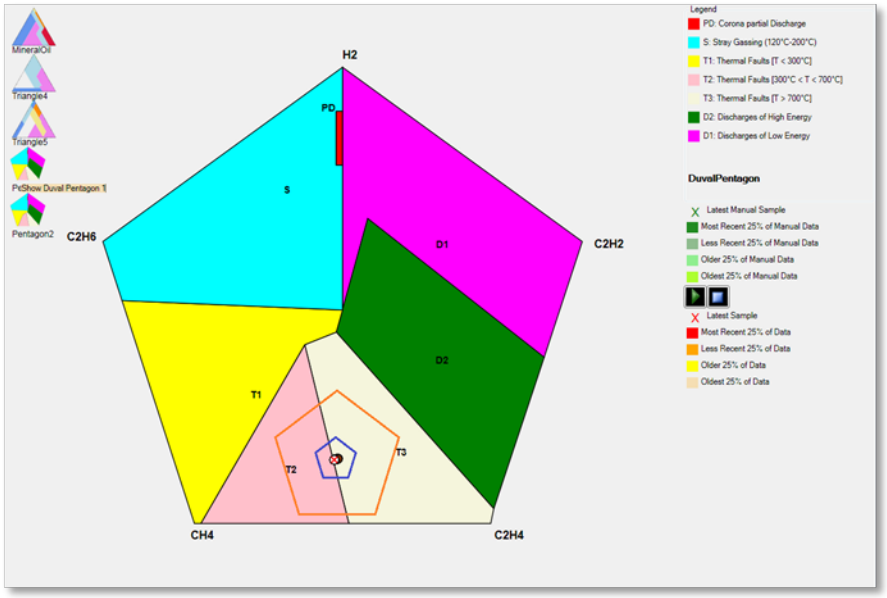

Figure 1. Duval Pentagon #1. The plotted data points (red "x") correspond to the centroid of the pentagon with apices at the percent composition for each gas relative to the sum of the five gas concentrations. In this case the gas concentrations were: Hydrogen, 4.9 ppm; Ethane, 66.0 ppm; Methane, 44.2 ppm; Ethylene, 109.6 ppm; Acetylene, 0.0 ppm. Small blue pentagon: area of uncertainty for highly accurately known gas concentrations. Large orange pentagon: area of uncertainty for less accurately known gas concentrations. Point (X) in red represents the most recent result; additional earlier points can be discerned behind it.

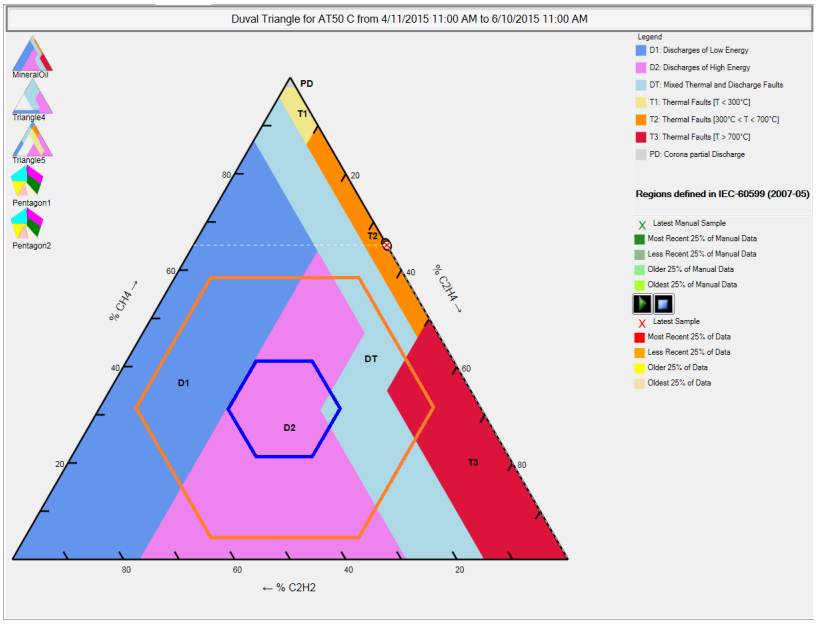

Figure 2. Duval Triangle #1. Effect of inaccuracies of 30% and 75% on diagnostic uncertainty. Small blue hexagon: area of uncertainty for typical accurately known gas concentrations at low ppm levels (30%). Large orange pentagon: area of uncertainty for less accurately known gas concentrations. In this case the reference result would be positioned at the centroid of the triangle. It can be easily seen that when an area of uncertainty crosses several fault zones, a reliable diagnosis cannot be given.

The well-known original Duval Triangle (Figure 2) utilizes ratios of three key gases – methane, ethylene, and acetylene – and other related triangles include combinations with hydrogen and ethane. The pentagonal version (Figure 1) incorporates all five in a single view that also nicely depicts the progression from formation of mostly hydrogen at low energies through ethane, methane, ethylene, and finally acetylene at the highest energy levels. Consideration of the

carbon-oxide (CO, CO2) levels along with these graphical presentations can reveal much about the state of a transformer.

III. THE IMPORTANCE OF ACCURACY

The uncertainty in the location of a data point in the triangular or pentagonal DGA plots is a function of the accuracy and repeatability of each gas concentration. Generally, concentrations greater than five times the minimum detectable amounts, and that are known to be accurate within ±15% or better after correction for known measurement bias, can provide meaningful interpretive results. Less precise or less accurate values can result in ambiguities in the fault-type zone (T1, T2, T3 … and so-on) that will make it more difficult to positively determine appropriate action.

Figure 1 shows the effects of accuracy and precision with two pentagonal areas around the data points. The smaller blue area depicts a higher degree of accuracy and precision while the larger orange area indicates the effects of comparatively less accuracy and worse precision.

Figure 2 shows a similar representation of the effect of inaccuracies, this time the impact of results that are 30% and 75% removed from the true. While the hexagons depicted in the triangle illustrate the uncertainty if all the gases were reported inaccurately, it does serve to illustrate that the further removed a result is from the true result the more likely an inaccurate diagnosis will be determined.

The desired maximum amount of uncertainty in the diagnostic result drives requirements for oil sampling and analysis. The analytical results upon which meaningful interpretation and diagnostic conclusions can be made therefore must be of sufficient quality to support any proposed actions on that basis. With frequent acquisition of new test results comes the ability to quickly react to trends that otherwise would not be apparent with fewer DGA analyses acquired at longer intervals.

While trending does provide an important indication of a change occurring and is relatively immune to the absolute accuracy of the results, inaccuracies in the measurement may delay the raising of an alarm or may result in an early alarm. Any diagnosis must be taken in the context of known accurate results.

IV. ONLINE DGA TECHNOLOGIES

Online DGA sampling evolved out of the need to obtain samples on a more frequent basis. Analyzing oil samples from large transformers on a 1-3 year basis may be statistically acceptable and relevant, but failures can develop very quickly within a transformer, over a matter of months, weeks, or even days. A transformer could easily be saved from failure, catastrophic or otherwise, if DGA oil samples were tested on a more frequent basis. Accordingly, the introduction of online hydrogen monitors in the late 1980s and of multi-gas monitors in the early 2000s provided timely enhancements to manual DGA analysis. Both types provided the ability to make available analysis results as frequently as hourly.

Single-gas monitoring

Online monitoring systems have evolved from single to multi-gas capabilities. Initially, hydrogen measuring devices provided necessary alarms but only as related to measurement of hydrogen and some of the other combustible gases. In one hydrogen monitor design, the gases migrate through a permeable polymer membrane and into a fuel cell to create an electric current proportional to the gas concentration in oil. Another variant uses a bundle of tubes to extract hydrogen from the oil and then measures the hydrogen concentration with a thermal conductivity detector. These devices function like a “smoke” alarm, which signals for an oil sample to be extracted and thoroughly tested in the lab. These H2 sensors provide less than one hundred percent selectivity for hydrogen, and they respond to a lesser degree to other combustible gases such as acetylene or carbon monoxide. Even so, they do provide a valuable indication that there is some activity in a transformer that may need to be investigated.

More recently, in 2012, a new generation of hydrogen DGA devices emerged. These utilize an oil-immersed catalytic hydrogen sensor without membrane, fuel cell, or TCD, and they respond selectively to hydrogen only. The relative simplicity and more direct measurement means they can deliver better accuracy and reliability than first-generation hydrogen-monitoring devices.

Multi-gas monitoring

From around the year 2000 to the present, multi-gas online DGA monitors have brought laboratory analysis capabilities directly to generation and substation locations. Multi-gas DGA systems measure some or all of the principal DGA fault gases by combining gas-extraction technologies connected directly to the transformer oil tank with laboratory-quality analytical measurement engines. DGA diagnostic software provides an indication of the nature of detected fault conditions as well as a relatively data-dense view of gassing levels and trends over time. Figure 3 shows a typical gas concentration–time graphical presentation from an online DGA monitor in which the development of a serious fault is observed over a very short period.

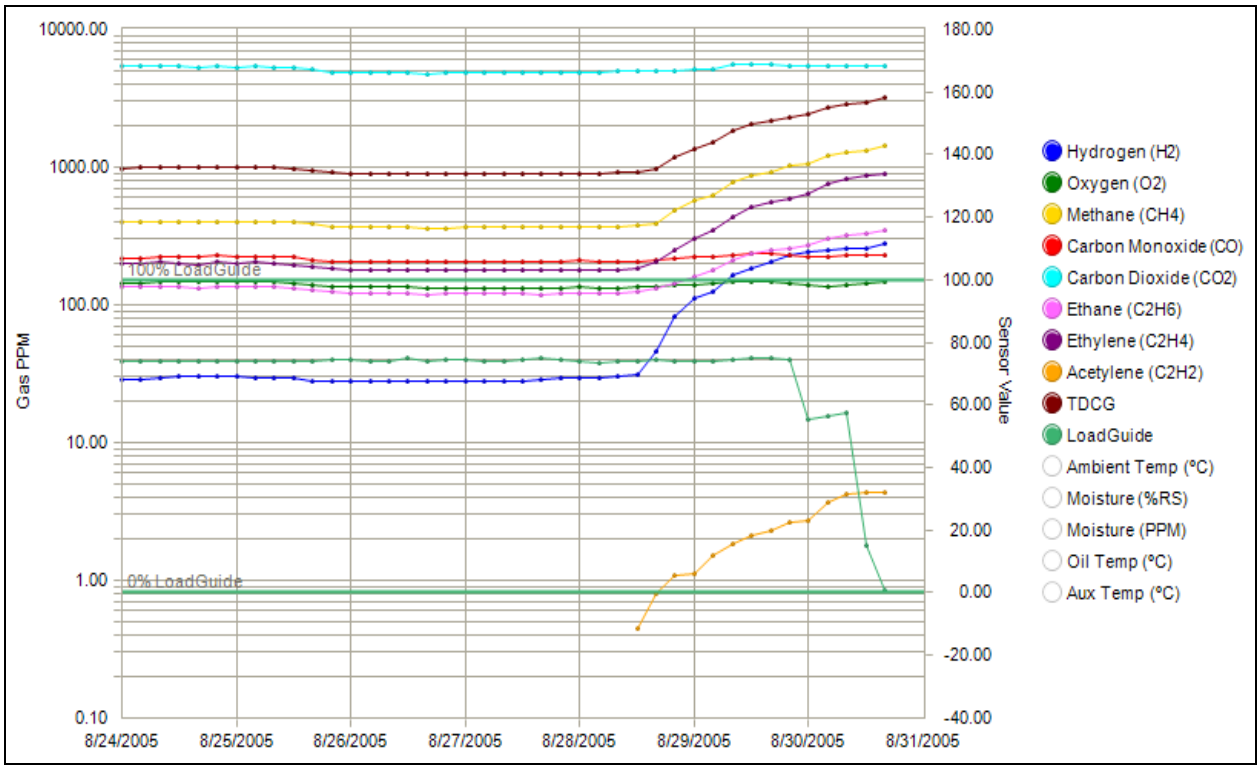

Figure 3. Monitoring from fault to shutdown of a 3-phase, 1100 MVA, 345 kV GSU transformer. Time from first detection of faulting to decision to shut down is slightly more than 48 hours.

The capability to obtain this detailed DGA data comes with a secondary requirement: an operator must observe the data more frequently in order to react in a timely manner. For this to occur there must be available computing equipment and data channels to bring the data to the decision-maker. Online monitors make their data available in a number of ways that range from simple status and alarm condition lights on the monitor itself to implementing more sophisticated standards such as IEC 61850, DNP3, and Modbus, thus integrating well with existing data channels in many locations.

Gas Extraction

Obtaining DGA data is a two-step process: (1) gas extraction followed by (2) gas measurement. In an online system these two are combined into a single unit, while in the lab they are most often separated into discrete functional devices. Two types of gas extraction system are commonly employed for online monitoring: a headspace type of gas extraction, or a membrane-based extractor.

A headspace design, not shown here, captures a fixed amount of oil and then sparges the oil with a mixture of outside air and transformer gas in a dynamic headspace sampling arrangement, without a membrane. This type of system must then remove any added air before recirculation the measured oil back to the transformer. Care must be taken in the design to prevent the entrainment of oil aerosols into the gas-side circulation paths that lead to the gas analyzer.

A gas-permeable membrane prevents liquid oil, foam, and aerosols from entering the gas space that is connected to the gas analyzer while allowing the DGA gases to permeate through. The membrane does not affect the equilibrium concentrations that the gases attain, but it does influence the rate at which gases permeate between the oil and gas spaces. Similarly to the laboratory headspace sampling method, gases partition through the membrane or a bundle of smaller membranes until equilibrium is reached.

A simplified diagram of a GC-based online DGA monitor with membrane extraction is shown in Figure 4. The oil side of the extractor connects the system directly to the transformer tank in a sealed loop, which eliminates the variability that can be associated with manual oil sampling. The oil circulation system is sealed, no fault gases can exit the system, and atmospheric gases cannot enter. A small amount of the dissolved gases passes from the continuously circulating oil through a gas-permeable membrane for measurement. The volume of gas removed from the oil is on the order of milliliters, an insignificant fraction of the total volume of dissolved gas held in the transformer tank; this has no effect on the total dissolved gas levels.

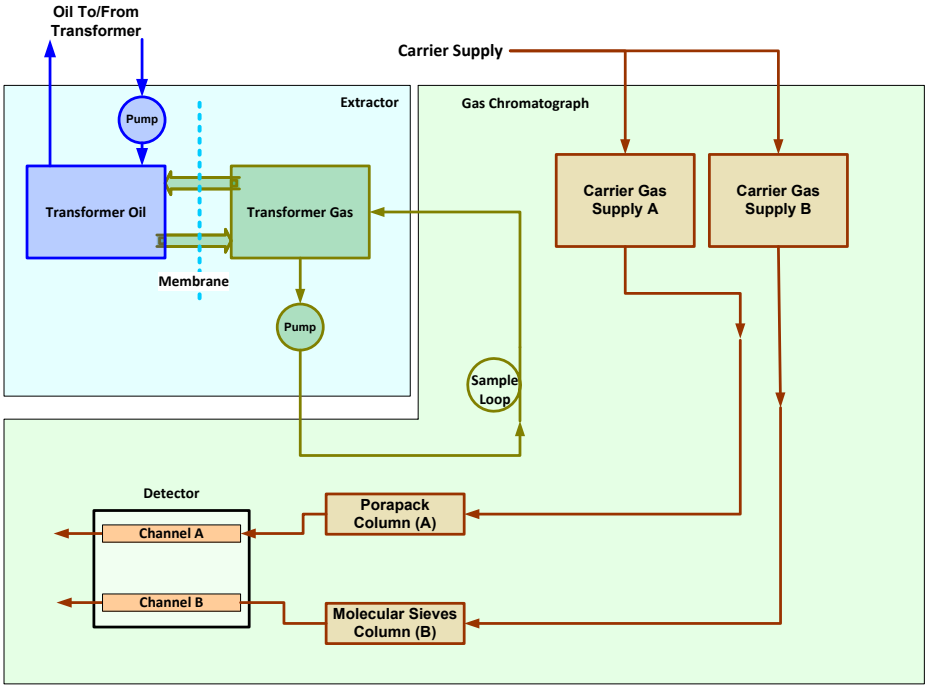

Figure 4. Online DGA–GC system basic diagram. Dissolved gases pass through a gas-permeable membrane into a gas plenum and the GC sample loop. When ready, the loop contents are transferred to the GC columns for separation and measurement.

Gas Measurement

After gas extraction procures a gas sample for analysis, a gas measurement system determines the gas-phase concentrations of all of the fault gases of interest, which are then converted via calibration to gas-in-oil concentrations and reported for further diagnostic work-up. Three types of analytical measurement systems have been deployed in online DGA monitors: gas chromatography, mid-infrared spectroscopy (MIR), and solid-state sensors. From a historical point of view, GC is the DGA reference technique stipulated in the ASTM and IEC laboratory standard procedures.

Gas chromatography

In a gas chromatography analysis, the compounds of interest — the DGA fault gases — are presented simultaneously into the beginning of one or more separation columns. Carrier gas flow — argon or helium in most cases — moves each substance through the column or columns at different rates, as a consequence of selective interaction of the columns' internal stationary phase with the gases. The compounds emerge from the end of the column in sequence and, ideally, completely separated from each other. They are transferred to one or more detectors that respond in proportion to their concentrations: the detectors' responses are measured and converted to ppm values. Thus in a well-designed GC system, all of the DGA gases can be separated and measured independently of one another.
Gas chromatography systems, by virtue of their complete gas separation, can easily be calibrated and verified with an in-field gas standard.

Infrared spectroscopy

Infrared (IR) spectroscopy is an alternative technique to GC for the measurement of DGA gas concentrations. The light absorption characteristics — the spectra — of the DGA gases are shown in Figure 5. While carbon dioxide, carbon monoxide, and acetylene have well-defined spectral regions with little interference from other compounds likely to be present, methane and the other hydrocarbons present overlapping spectra. This is in contrast to GC where all of the compounds are separated before arriving at the detector. When these gases are present at the same time, any single optical band in their shared absorption range contains varying responses from each of the gases. Calibration can

establish the responses at multiple wavelengths for each pure gas, but finding individual gas concentrations from the responses to a mixture is more complex.

In many cases it is possible to pull the individual gas absorptions apart using high-resolution spectral techniques such as Fourier-Transform Infrared (FTIR). However, deploying such a sophisticated instrument at a transformer is neither practical nor cost-effective. Instead, IR DGA monitors rely on nondispersive infrared (NDIR) measurements that place a series of selective IR bandpass filters into the light beam to restrict the observed wavelengths.

Multivariate deconvolution techniques are employed to compute individual gas concentrations from multiple measurements of the overlapping hydrocarbon absorptions. Calibration of an IR system for this type of analysis requires careful measurement of the spectral responses to each gas individually. Thus it is not particularly practical to fully recalibrate in the field as this would require presenting the system with each pure gas at multiple concentrations.

During gas concentration measurement, the absorption of infrared light by DGA gases can be measured either by the attenuation of a light beam in the presence of the DGA gases compared to the intensity of a 100-percent transmitted beam in their absence, or with a photoacoustic spectroscopic (PAS) detector.

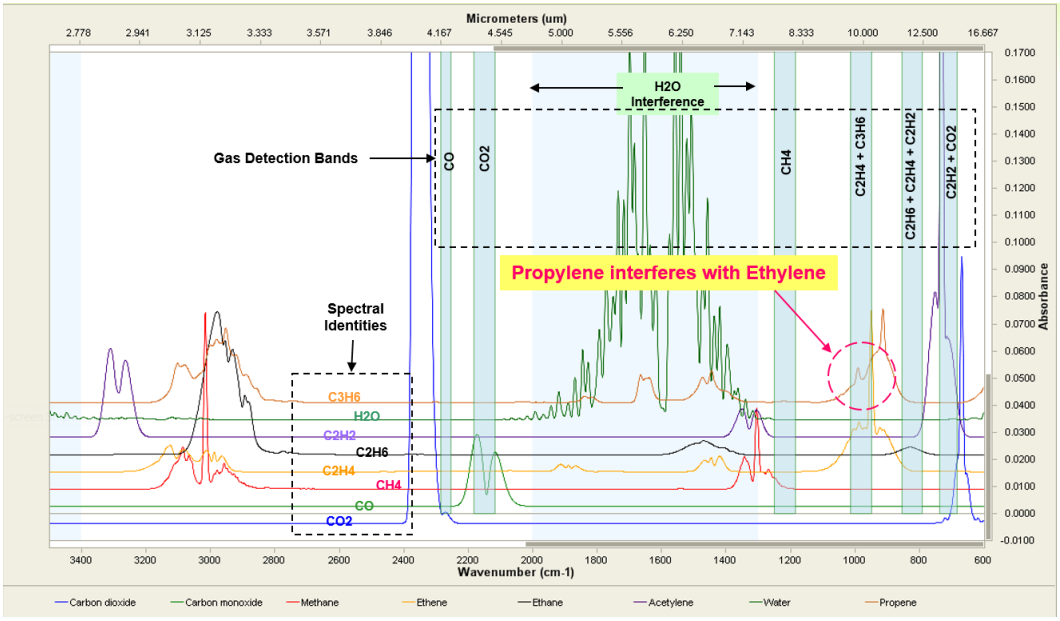

Figure 5. Infrared spectra of DGA gases. Note overlapping spectra for the hydrocarbons including propylene, both in the 7 – 12 µm range as well as at shorter wavelengths around 2 – 4 µm.

In PAS, the absorption of light energy causes the DGA gas sample to heat up slightly. When the incoming IR light is pulsed, the resulting pressure pulsations caused by gas sample heating and cooling are picked up by ultra-sensitive microphones. The pulsed signal is demodulated by treating the pulse train as a carrier wave, to yield a measure of the intensity of light absorption. PAS can be sensitive into the sub-ppm range and is relatively stable. It is a direct absorption measurement method in which zero absorption corresponds to zero signals.

V. CONCLUSION

The critical nature of transformers and the recognition that they need continuous maintenance and a thorough understanding of multiple potential failure processes has raised the importance of dielectric fluid analysis to the forefront. This is part has been driven by the need to obtain better and faster analyses and a better methodology of defining the health of the asset. Multiple technical approaches have been used to obtain online DGA data. Sufficiently sensitive, accurate, and repeatable results can form a strong basis for interpretation and diagnostics. Current efforts to develop multi-disciplinary condition-based monitoring systems will bring the science of transformer diagnostics to new levels, accompanied by better management of these critical energy system assets.

VI. REFERENCES

[1] M. Duval, " The Duval Pentagon, A New Complementary Tool for the Interpretation of Dissolved Gas Analysis in Transformers," *IEEE Electrical Insulation Magazine*, vol. 30, No. 6 pp. 9-12, Dec. 2014.