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# Guide for Interpreting Dissolved Gases in Liquid-filled Transformers



Scientific Easy Independent



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### Preface

Dissolved-gas analysis (DGA) is currently – in the early 2020's – used world wide as a non-intrusive and relatively inexpensive method for periodic diagnostic screening of liquid-insulated electric power apparatus, especially power transformers. DGA guides have been published by major international standards organizations such as IEC and IEEE as well as by regional and national organizations and government departments. Power industry trade magazines often have articles on DGA. So why are we publishing a guide for power transformer DGA?

In the 1970's, computers were available for important things like accounts receivable, nuclear physics, and government statistics, but not so much for transformer diagnostics. In those days, when DGA ceased to be an experimental curiosity and became a widely adopted practice for screening transformer fleets, the interpretation of DGA was necessarily based on limit comparisons, slide rule calculations, and graph paper. Some of the pioneering chemists and engineers who first worked out the concepts and methods and established the limit values are still with us at the time of writing this. The inertia of an industry focused on safety and reliability has carried the original ideas and practices of 1970's DGA forward for decades because those were very effective at identifying transformers that needed attention and preventing catastrophes.

We live in an age where telephones are computers, filing cabinets are computers, children play with computers, no one knows how to work a slide rule, and graph paper is not needed so much because – computers. Computers have revolutionized statistics, digital signal processing, data visualization, data storage, and communications. Computers are under the hood of your car, and now – in DGA. The ability to do a billion calculations at the touch of a finger has given us the opportunity to revisit the physical and chemical basis of DGA, to use modern statistical techniques, and to apply more computation intensive methods of visualizing and interpreting DGA data. The result of this work, carried out by many people (including some of the pioneers) over the last decade, is an approach to transformer DGA that actually does provide better understanding and better performance than legacy DGA.

This tutorial guide to DGA does not contain instructions for use or development of software. It is a resource for understanding what DGA is and how to understand the data. It should enable the reader to read DGA reports intelligently and critically and to make reasonable judgments about the relative amount of risk implied by DGA results in individual cases.

The author is profoundly grateful to the many DGA experts from whom he learned, including (in no particular order) Fredi Jakob, Stan Lindgren, Paul Griffin, John Lackey, Don Platts, Tom Lundquist, Ted Haupert, Joe Kelly, Michel Belanger, Dave Hanson, Claude Beauchemin, Tom Rhodes, and Michel Duval. There are more who should be listed, but (sorry) the brain cells that remembered their names are gone now. These teachers may be grimacing at errors and omissions here, which are entirely the author's responsibility.

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#### Keywords

DGA, dissolved-gas analysis, fault energy index, fault gas, gassing trend, mineral oil, NEI, R-DGA, transformer

#### Scope

The scope of this guide is limited to dissolved-gas analysis (DGA) for oil-immersed power transformers that are in service.

### Other transformer and applications

Certain specialty applications and types of transformers, such as network transformers, traction transformers, rectifiers used in production of metals and glass, and wind farm transformers, may have structural or operative features that require modification of the DGA interpretation approach presented here. In particular, for transformers with ester, silicone, or other alternative insulating liquids, the fault energy indices, fault type identification methods, and reliability models must be adapted to the chemistry of gas evolution from those liquids.

Periodic screening DGA is not applicable to some types of transformers. For example, drytype transformers have no insulating liquid and therefore no dissolved gases. It is not costeffective to do periodic DGA testing for very small oil-immersed transformers because annual DGA testing or online DGA monitoring would, on average, cost more than simply running them to failure.

#### Prerequisites

The reader is expected to be familiar with basic terminology and concepts relating to electric power systems, chemistry, statistics, and general technical mathematics.

### Disclaimer

This document is not meant to be a substitute for a detailed operational and site specific transformer testing and maintenance plan. Delta-X Research is not responsible or liable for misuse of the information contained herein. No representation is made or warranty given, either express or implied, as to the completeness or accuracy of the information in this document. If you have any suggestions for improvements or amendments or have found errors in this publication, please notify us.

# Introduction

### 1.1 Power transformers

A power transformer is a laminated steel core wound with paper-insulated copper conductors. The windings may be divided into sections by pressboard spacers. To prevent fatal deformation due to strong magnetic force when there is a short circuit, the windings are kept under great compressive force by clamping. A transformer of the kind discussed in this guide is contained in a steel box, called the main tank, filled with mineral oil.<sup>1</sup> A gas-filled headspace (or gas space) is provided to allow thermal expansion and contraction of the oil without rupturing the main tank.

Mineral oil and oil-saturated kraft paper are good high-voltage insulating materials, but they must be protected from oxygen, water, and temperatures over about 100°C, which degrade the oil and paper. A cooling system is provided to prevent overheating. It can range in complexity from cooling fins on the outside of the main tank of a small transformer to oil pumps and radiators with fans on a large transformer. The gas space can be configured and managed in various ways to provide protection from oxygen and water. For example, the oil protection system may be a simple desiccant breather, a nitrogen pressure regulation system, or a conservator with its own oil and gas space in a separate container above the main tank. A good general overview of power transformers and their testing and maintenance is given by [3], among many other references that can be found on the Internet. Power transformers are essential and critical components of an electric power system. In most applications they are in operation continuously for years at a time. Unplanned outages can be extremely expensive and can result in hazardous conditions. Replacements for large or specialized transformers may take years to obtain. For all these reasons a simple, inexpensive, non-invasive means of periodically checking energized transformers and detecting trouble early enough to permit mitigation or remedial action is vital. Currently that is dissolved-gas analysis (DGA).

Other possibilities, not discussed in this guide, are that the main tank could be filled with an alternative liquid such as vegetable or silicone oil, or the transformer could be dry, located in a gas-filled container or a shed instead of a main tank.

#### 1.2 Dissolved-gas analysis

Veteran transformer engineers and substation technicians have known for a long time that faulty transformers sometimes smell bad. In particular, they may smell of acetylene. In the 1960's combustible gas detectors began to be used on gas space samples from energized power transformers for screening and diagnostic purposes. At that time, the fraction of combustible gas in the gas space was the main diagnostic quantity. The proportions of individual combustible gases in the gas sample were sometimes evaluated using mass spectrometry or primitive chromatography, but that was slow and costly [4]. Since the 1970's, gas chromatography has been used to do dissolved-gas analysis (DGA), allowing for the measurement and interpretation of concentrations of individual combustible gases dissolved in the oil [5], [6]. The principle is still basically to sniff the oil to detect baked, fried, or electrocuted insulating material, but now sensitive instruments are used instead of a nose.

DGA is now a very widely used nonintrusive and relatively inexpensive way to check operating transformers periodically and determine whether or not they seem fit for continued service.

DGA is now a very widely used non-intrusive and relatively inexpensive way to check operating transformers periodically and determine whether or not they seem fit for continued service. It is also increasingly common to employ online DGA monitors for continuous tracking of one or more gases in transformers. When there is abnormal gas production, DGA can identify the approximate nature and relative severity of the problem so that followup testing or other action can be scheduled. The dissolved gases that are of principal interest for DGA (fault gases) are formed by the exposure of insulating oil, paper insulation, and pressboard spacers to abnormal conditions - high temperatures, sparking or arcing, or corona discharge. Oxygen and nitrogen levels can be used to verify the normal functioning of the oil preservation system and to detect air leaks.

International standards organizations publish guides (not standards in the prescriptive sense) and other references for power transformer DGA that contain much useful information and should not be ignored. Prominent examples include [7], [8], and [9]. This Guide is a tutorial and reference document whose purpose is to teach the reader how to do DGA interpretation, making use of several advancements in DGA practice that have been discovered within the recent decade.



#### 1.3 The Fundamental Principle of DGA

The job of a power transformer is the inductive transfer of large amounts of power from one electrical circuit to another, minimizing losses. Transformers are designed to perform this function for a very long time (typically several decades) within rated limits and under specified operating conditions without damaging or destroying the internal electrical insulation. Therefore, when insulation deterioration by-products are being formed in a transformer beyond what is expected due to normal aging, something is wrong.

### 1.4 What is the purpose of transformer DGA?

In general, DGA is intended to provide early detection and preliminary diagnosis of abnormal conditions within the transformer so that unnecessary safety hazards, deterioration, damage, forced outages, and catastrophic failure can be avoided.

Because there are relatively harmless conditions that can cause serious looking fault gas production, it is important to understand that the final word on the transformer's condition and fitness for service must be based on physical and electrical tests, inspection, and other evidence such as operating and maintenance history. Similarly, a low oil pressure or high engine temperature warning light in a car would normally be responded to by investigation and testing. The owner should be cautious about operating the car until the cause of the warning is understood and dealt with, but it would not usually be reasonable to scrap or sell the car solely on the basis of a warning light.

### 1.5 What gases are considered in transformer DGA?

Transformer DGA is concerned with certain gaseous by-products of thermal and electrical decomposition of insulating materials. Often referred to as fault gases, they are:

- Hydrogen (H<sub>2</sub>)
- The low molecular weight hydrocarbon gases<sup>2</sup>
  - Methane (CH<sub>4</sub>)
  - Ethane (C<sub>2</sub>H<sub>6</sub>)
  - Ethylene (C<sub>2</sub>H<sub>4</sub>)
  - Acetylene (C<sub>2</sub>H<sub>2</sub>)
- The common carbon oxide gases
  - Carbon monoxide (CO)
  - Carbon dioxide (CO<sub>2</sub>)

The primary atmospheric gases oxygen  $(O_2)$  and nitrogen  $(N_2)$  are also of interest since they provide direct evidence regarding the integrity of the transformer's oil preservation system and indirect evidence concerning other matters of potential interest.

 $<sup>^{2}</sup>$  Some DGA methods also measure and interpret the so-called C<sub>3</sub> hydrocarbon gases propane (C<sub>3</sub>H<sub>8</sub>), propene or propylene (C<sub>3</sub>H<sub>6</sub>), and possibly also the C<sub>4</sub> hydrocarbon gases butane (C<sub>4</sub>H<sub>10</sub>) and butene or butylene (C<sub>4</sub>H<sub>8</sub>).

### 1.6 How is DGA applied to transformers?

For transformers in service, DGA is used in four distinct ways [7].

#### Initial assessment

For an individual transformer, DGA is performed soon after energizing or repairs to verify that the transformer is not defective or over-stressed and to obtain baseline data for comparison with future DGA results. Additional DGA testing may be conducted during the first few days or weeks of operation to detect any early signs of abnormality.

#### Screening

DGA is applied to transformer fleets as a periodic (usually annual) screening technique to identify and prioritize those transformers that may require surveillance, investigative testing, or other intervention. Transformers are ranked according to their apparent need for supplementary attention or intervention, according to the interpretive results.

#### Surveillance

For individual transformers that have been identified as high-risk units, for example because of active fault gas generation, DGA testing may be performed more frequently for investigation and fault diagnosis or for safety pending removal from service.

#### Monitoring

Performing DGA sampling and measurements several times a day, whether manually or by an automated device, provides continuous awareness of a transformer's status and facilitates tracking its response to varying load and environmental conditions and to stressful events which may occur from time to time. Online DGA monitoring applied to many transformers simultaneously is a combination of surveillance and screening and may be used for ranking transformers (see Screening above).

For transformers not in service, DGA is used for factory acceptance testing and occasional checking of transformers in reserve that are energized with a small current. DGA is sometimes also performed for quality control purposes, such as to verify a previously obtained exceptional DGA result or to compare DGA results between labs for samples of the same oil.



# How to do DGA

#### 2.1 Data quality

Throughout the DGA process of sampling, analysis, data manipulation, interpretation, and reporting, it is mandatory to watch for and remedy errors, discrepancies, and other problems that may lead to a misleading interpretation. Do not include any results based on erroneous or dubious data in your final conclusions. If necessary (and possible), order a supplementary oil sample or analysis to clear up uncertainty and to verify alarming results.

The gas concentration values given in a DGA lab report are the result of a very complex process of sampling, transport, storage and handling, lab processing, and measurement. It is not surprising, then, that errors, omissions, and misidentified data turn up from time to time. Before interpreting newly received data or believing alarming interpretive results, it is necessary to check the data and resolve any problems that may be found. If any changes are made, it may be necessary to re-do some calculations Common examples of data quality problems (see also [7]) are:

**Mis-identification:** Strange inconsistencies or a shocking diagnosis may result from mis-identification of an oil sample or DGA report. For example, the sample could be from the wrong oil compartment (e.g. LTC compartment instead of main tank) or from the wrong transformer (e.g. transformer T3 at a different substation).

Repeated digits: Example: 211 instead of 21.

Transposed digits: Example: 91 instead of 19.

**Mis-recorded data:** Example - Oxygen concentration recorded as nitrogen and vice versa. CO and CO2 concentrations are also sometimes interchanged.



**Missing data:** Missing numeric values may be blank, which may or may not be harmful for calculations. If missing values are represented by non numeric expressions such as NA or ND, they may cause computerized calculations to fail. Worst of all is for missing values to be misrepresented as zero or a DPOA value, or as a numeric code such as -99.

**Inconsistency due to mixed data sources:** DGA data obtained from different sources, such as multiple laboratories and portable instruments, may be somewhat inconsistent due to systematic measurement differences between sources.

Variability due to unrepresentative samples: Poor sampling practice can lead to extreme data inconsistency from sample to sample [10].

Bad measurement values due to mishandling of a sample: If an oil sample is exposed to air or bright light, some of the dissolved gas content may change. Gas loss by leakage or expulsion of a bubble from the sample syringe is usually noticeable by very low hydrogen and CO content compared to earlier samples, especially if the oxygen/nitrogen ratio is above about 0.3 and inconsistent with earlier samples.

Note that low measurement values due to gas loss from the transformer is not a data quality problem, in that the gas concentrations reported fairly represent what is found in the transformer. Recognition of transformer gas loss and interpretation of the associated DGA data are discussed in section 2.5.1.

#### 2.2 Oil sampling

The purpose of oil sampling is to obtain an uncontaminated sample of oil that is chemically and physically representative of most of the oil in a designated oil compartment, usually the main tank [11]. For manual sampling from the transformer's drain valve, an important part of the sampling procedure is to bleed off enough oil before sampling to avoid collecting unrepresentative stagnant oil.

Be Safe! A vital safety issue when sampling transformer oil or connecting a DGA monitor to a transformer is to be sure that the transformer oil is under positive pressure before opening a valve or connection. According to [12], "There is no way to safely sample a transformer while it is under vacuum or negative gauge pressure. Be certain to confirm positive pressure before sampling."

A common type of container for collecting and shipping DGA oil samples is a 50-ml glass syringe. Clean syringes boxed for shipment can usually be obtained from the analytical lab that will do the gas analysis.

It is important to label each oil sample container accurately and legibly with the sample date and time, transformer manufacturer, serial number, other ID number (if available), oil compartment designation, owner, location, and bank and phase designation. Other information such as oil preservation type, cooling type, number of phases, and MVA and kV ratings may also be desired by the lab.

Improper sampling technique or the use of inappropriate sample containers can result in misleading gas analysis results or poor data quality [10]. For monitoring devices, it is important that the oil inlet be located where the oil is not stagnant, so that the measured gas concentrations will be representative of most of the oil content of the main tank. For example, the drain valve is usually not a good location for a DGA monitor oil inlet.

#### 2.3 Gas analysis

DGA oil samples should be delivered to a qualified and reputable transformer oil laboratory for gas analysis. Laboratory analysis of DGA oil samples requires specialized knowledge and equipment that may not be available to an environmental or materials testing lab, for example.

Laboratory gas analysis is performed according to a published measurement standard such as ASTM D3612 [1] or IEC 60567 [2] in multiple stages including extraction of gases from the oil, chromatographic separation and measurement of individual gases, and calculations to adjust for temperature, solubility, and other factors.

Measurement data, laboratory remarks, and some form of interpretation are usually provided to the customer in a report which may be supplied on paper or in PDF (electronic document) or spreadsheet format. The test data may also be available in another digital format convenient for transfer to a database.

If a quick gas analysis is required, a field-portable gas analyzer can be used to obtain measurement results on site. A portable instrument automates the measurement procedure and employs either a miniaturized gas chromatograph or other technology to do the gas concentration measurements. The gas analysis performed by a portable instrument may not conform to a recognized measurement standard, and consequently the measurement results may or may not agree well with what would have been obtained by laboratory analysis. An online DGA monitor, mounted on or near the transformer and connected to a sampling port on the transformer by steel tubing, draws oil samples automatically at a preset frequency (such as four times a day) and performs the gas analysis similarly to a portable gas analyzer, recording time stamped measurement data internally for retrieval by an external computer or other device. As noted for portable instruments, the measurement results from a DGA monitor may or may not agree well with laboratory results for oil samples taken manually at about the same time as the monitor samples. Some differences in measurement results may also be attributable to the fact that the monitor samples and the manual samples are drawn from different sampling ports in different ways. The degree of agreement between DGA monitor and laboratory analysis results is discussed in CIGRE technical bulletins 409 [13] and 783 [14].

The SI units for dissolved-gas concentration in oil are microliters per liter ( $\mu$ L/L), informally called parts per million or ppm. The measurement procedure specifies that the gas concentration shall be reduced to standard temperature and pressure conditions for reporting. For example, ASTM D3612 gas concentrations are reported at 101.325 kPa (1 atmosphere) and 273.15 K (0°C) while IEC 60567 gas concentrations are reported at 101.325 kPa (1 atmosphere) and 293.15 K (20°C).

Once obtained, the new gas concentration data must be appended to the previously accumulated DGA data for the transformer to update the transformer's DGA history, which is the proper object of study and interpretation.

#### 2.4 Diagnostic quantities

In IEEE Std C57.104-2019, section 6.1.4, the claim that "DGA interpretation is still more of an art than a science"<sup>7</sup> is given as a reason for seeking expert help. It might have been more accurate to say that "if you don't approach DGA interpretation scientifically, you will need help from some one who does." The laboratory (or portable gas analyzer or monitoring device) measures and reports gas concentrations, but the measurement numbers are only indirect indicators of the transformer's status and sometimes are very imprecise. Instead of interpreting the reported numbers directly, it is useful to calculate from the reported gas data some diagnostic quantities that are easier to visualize and interpret, based on the entire DGA history of the transformer, and taking physics, chemistry, and statistical issues into account.

#### 2.4.1 Estimated fault gas production

The Fundamental Principle of DGA, stated in section 1.3 above, reminds us that DGA is about gaseous byproducts of insulation deterioration, especially when they are being formed at an unusual rate. The interpretation of gaseous deterioration byproducts logically should involve quantifying the amount of deterioration, which in turn would be related to the amount of each gas generated by a fault. But the gas concentration measurements reported by the laboratory, portable gas analyzer, or DGA monitor may fail to be fair representations of gas production to date for two reasons:

 Gas concentration measurements can be very imprecise, due partly to measurement uncertainty – typically around ±15% for lab data, ±5% for portable analyzers, and ±2% for DGA monitors [15] – and partly to problems of manual oil sample collection and handling, which can easily contribute additional variability of ±5% – 15% or more [10]. See Figure 2.1 (next page). Calculating with DGA monitor gas concentration data requires due attention to high frequency ±2% noise as well as occasional blips and calibration drift. See Figure 2.2 (next page).

7 IEEE Std C57.104-2019, section 6.1.4.



**Figure 2.1: Chaotic pattern.** Poor sampling practice may fail to obtain oil samples that are truly representative of the main tank oil. Mishandling of oil samples, such as by exposing them to light or large temperature changes, can also result in data quality problems. A common symptom of poor sampling and handling is inconsistent, extremely noisy data. Would you guess that the pattern shown is a level trend with noise?



Figure 2.2: Glitches in online monitor data. Online DGA monitoring usually produces gas data with low average noise, as shown, but possibly with occasional extra "features" such as spikes, dropouts, and baseline shifts. Other patterns, not shown, are bursts of extreme noise, data outages, artificial trends due to calibration drift, and long-term variation due to seasonal changes in external temperature.

2. Gas loss by leakage or by expulsion by headspace pressure regulation reduces the amount of gas produced by an unknown amount at an unknown rate. Deliberate bulk degassing of the oil removes a large proportion of the gas present in the oil over a few days or weeks. See Figures 2.3, 2.4, and 2.5.



Figure 2.3: Steady decrease. A persistent downward trend indicates gas loss, probably by leakage through a faulty bushing gasket or other small opening. Since gas leakage is accompanied by ingress of atmospheric gas and moisture, supporting evidence of leakage would be a high average O2 /N2 ratio during the downward gas trend, persistent low levels of hydrogen and carbon monoxide, and increasing water in oil or relative saturation.



**Figure 2.4: Zig-zag pattern.** Gas loss intermittently exceeding the rate of gas production tends to produce a saw tooth pattern, in which an upward trend is repeatedly interrupted by an episode of gas loss. This pattern often occurs in gassing transformers with a nitrogen pressurized headspace.



Figure 2.5: Interrupted trend. Bulk gas loss over a short time interval, such as by degassing of the main tank oil, can appear to interrupt an upward trend, but if the cause of the gas production has not been remedied, the trend will resume soon after the degassing.

Partial compensation for moderate gas loss can be obtained by summing positive increments of smoothed gas concentrations, assuming that the gas level started at zero. For example, if the gas concentrations over five samples are 25, 35, 30, 40, and 38, then the estimated gas production as of each sample is as shown in Table 2.1. Note that the increments are calculated using the data values, not the estimated production values.

 Table 2.1: Estimation of gas production from reported concentrations by adding positive increments of gas concentrations.

Number	Concentration	Increment	Production
1	25	(25-0)	25
2	35	(35-25)	35
3	30	(30-35)	35
4	40	(40-30)	45
5	38	(38-40)	45

This method of estimating gas production from sample to sample has been tested and refined so that in cases where there is no gas loss and very low noise the estimated production agrees well with the measured gas concentrations.



For a long time it has been conventional practice to interpret each fault gas individually to assess the transformer's status. But several years ago chemist Fredi Jakob realized that since the fundamental issue for DGA is whether any insulating material is being cooked, it makes more sense to consider fault energy instead of individual gas levels [16]. Compare **Figure 2.6** with **Figure 2.7** to see the point visually (next page).

There are two main insulating materials in a transformer – the oil and the cellulosic material, most of which is paper and thin pressboard. Under normal circumstances, both the oil and the cellulosic insulation materials very slowly generate a variety of different gases as they age under the influence of temperature, oxygen, and water. Under fault conditions, i.e., when some of the energy that should be flowing through the transformer is diverted into cracking the oil or charring the cellulose, either insulating material can generate hydrogen, while methane, ethane, ethylene, and acetylene are mainly produced by the oil, and carbon monoxide and carbon dioxide are produced mainly by the cellulosic insulation. It is useful, then, to trend and assess two fault energy indices – NEI-HC, based on hydrocarbon gases mainly generated from pyrolysis of cellulosic insulation. Details of their calculation are explained in **Appendix B**.

For DGA interpretation purposes, NEI-HC and NEI-CO are calculated from the estimated gas production values instead of the reported gas concentrations. The result of this, as shown by **Figure 2.7**, is the revelation of time intervals – shown with red boxes – during which active gassing has taken place. We call those intervals *gassing events*.



Figure 2.6: Hydrocarbon and hydrogen gas levels.



Figure 2.7: Cumulative normalized energy intensity (NEI-HC) of hydrocarbon gases. Red boxes mark time intervals during which there is active gassing.



Only ratios and proportions of meaningful quantities of gas should be interpreted (or even calculated).

In the case of diagnostic gas ratios such as  $CO/CO_2$ ,  $C_2H_4/C_2H_2$ , or  $O_2/N_2$ , it is useful to predefine "minimum interpretable" limits, above the respective analytical detection limits, below which the concentration or production quantity of each gas will not be used for calculating ratios. An example of a reasonable set of minimum interpretable limits for the DGA gases is given in Table 2.2.

Gas	Formula	MIL (( $\mu$ L/L)
Hydrogen	H <sub>2</sub>	25
Methane	CH <sub>4</sub>	10
Ethane	C <sub>2</sub> H <sub>6</sub>	10
Ethylene	C <sub>2</sub> H <sub>4</sub>	10
Acetylene	C <sub>2</sub> H <sub>2</sub>	1
Carbon Monoxide	СО	30
Carbon Dioxide	CO <sub>2</sub>	100
Oxygen	02	100
Nitrogen	N <sub>2</sub>	100

Table 2.2: Minimum interpretable limits for DGA gases

For gas proportions, such as would be used for Duval triangles, it is expected that some gas quantities (of hydrogen or hydrocarbon gas) might be very small, but the total amount of fault gas considered should be significant. One reasonable way to achieve this is to require that the root mean squared gas concentration should exceed 10  $\mu$ L/L.

### 2.5 Diagnostic interpretation

#### 2.5.1 Diagnosis of gas loss

After initially looking for and resolving data quality issues, it is advisable to check for evidence of gas loss, which can hamper or prevent the detection and assessment of fault gas production. Generally gas loss from transformer oil occurs in the following ways.

- Slow diffusion through a leaky gasket or other small opening, allowing fault gases to escape from the gas space and atmospheric gases and water to enter. This kind of leakage results in especially rapid loss of the not-so-soluble gases H<sub>2</sub> and CO, with lesser loss of the other fault gases. Oxygen and water vapor can enter the transformer through the leak. Thus, low concentrations of H<sub>2</sub> and CO, elevated oxygen concentration, high O<sub>2</sub> /N<sub>2</sub>, and spiking water concentration or relative saturation are confirming indications of a leak.
- In a nitrogen-regulated transformer, occasionally part of the headspace gas is expelled to relieve over-pressure, and fresh dry nitrogen is added as required to maintain positive pressure. The less soluble gases H<sub>2</sub> and CO are relatively more affected than the other fault gases. Because of the cycle of headspace gas loss and replenishment by nitrogen, oxygen concentration and O<sub>2</sub> /N<sub>2</sub> are kept low. A headspace gas leak or overly frequent pressure relief in a nitrogen-regulated transformer can result in unusually high consumption of nitrogen.
- Major bulk gas loss, such as by degassing of the transformer, quickly reduces all of the gas concentrations to almost zero. The gas concentrations increase for weeks or months after degassing, even if no new fault gas is being produced, due to rebalancing of the gas concentrations in the freely circulating main tank oil with the gas concentrations in the oil-soaked paper winding insulation. Usually degassing reduces the oxygen concentration and O<sub>2</sub> /N<sub>2</sub>.
- Gas loss from the oil can also happen after sampling, in the sampling syringe. Sometimes a gas bubble will form in the syringe. If that gas bubble is expelled or leaks out, much of the hydrogen and significant proportions of the other fault gases in the oil sample can be lost.
- If at any time during sampling or subsequent sample handling the oil sample is exposed to air, significant gas loss accompanied by increased oxygen and  $O_2/N_2$  will result.

Gas loss from an oil sample can be distinguished from leakage from the transformer in that the former typically affects only one oil sample, while leakage from the transformer is more gradual and usually affects several consecutive samples.

When there is gas loss, DGA interpretation becomes speculative and uncertain. It is important to find and remedy the cause of excessive gas loss if at all possible. Would an airline operate an airliner with inoperative warning indicator lights in the cockpit?

#### 2.5.2 Oxygen/nitrogen gas ratio

Oxygen, water, and high temperature are blamed for much of the deterioration of insulating materials in transformers.

The oxygen/nitrogen ratio  $O_2/N_2$  is a useful indicator of whether:

- A transformer is air-breathing, either by design or because of a leak;
- A DGA oil sample has been exposed to air.

Generally, a  $O_2/N_2$  ratio value of 0.2 or more suggests some air exposure. The ratio in air-saturated oil is close to 0.5.

#### 2.5.3 Carbon oxide gas ratio

Historically, evaluating carbon monoxide and carbon dioxide in terms of concentration and rate of change limits has not been a very satisfactory approach. For many years it has been understood, however, that the gas ratio  $CO_2$  /CO has some value for detecting deterioration of paper insulation. Very low values below about 2.5 were associated with paper deterioration due to high energy faults, while ratio values above 10 were associated with general overheating of paper insulation. Since each transformer tends to have its own typical level of  $CO_2$  /CO, however, the conventional limits of 2.5 and 10 had to be interpreted liberally.

Several years ago, utility engineer Chris Rutledge discovered that the best use of the  $CO_2$  /CO ratio is to interpret its percent change in response to a fault. That was confirmed and documented by Rutledge and Cox in several papers such as [17].

Because the measured concentrations of CO and CO<sub>2</sub> can be very noisy, it is common for the measured values of carbon monoxide and carbon dioxide to be extremely variable, i.e., to make large jumps or dips from oil sample to oil sample. It may be necessary to smooth and accumulate the CO and CO<sub>2</sub> time series, as discussed above, before calculating the ratio to avoid extreme variation due to the combined effect of the random errors in CO and CO<sub>2</sub>.

In the most serious cases of solid insulation deterioration, the production rate of CO greatly exceeds that of CO<sub>2</sub>, causing the ratio value to shrink towards zero, paradoxically getting smaller and changing less rapidly as severe charring is progressing. We prefer that diagnostic quantities should get larger in the worst cases, so for this DGA guide we employ the inverse ratio CO /CO<sub>2</sub>, mathematically adapting for it the criteria worked out by the original authors.

In general, carbon oxide gas production at a slow rate from both the oil and the paper insulation tends to keep the CO /CO<sub>2</sub> ratio fairly stable from year to year for transformers not experiencing problems or large changes in loading patterns. Each transformer can have its own typical steady-state value of the ratio.

General mild overheating of the transformer, as in cases where for some reason the cooling system fails to keep the transformer within its normal operating temperature range, can produce  $CO_2$  from the paper insulation, resulting in a downward trend in CO /CO<sub>2</sub>. On the other hand, a localized hot spot in paper insulation within the windings tends to produce a large increase in the ratio, while a hot spot in paper insulation outside of the windings – such as near a hot bushing lead connection – tends to produce a modest increase (See *Appendix C*). For those who like limit numbers, the recommendations of Rutledge and Cox, adjusted for the inversion of the ratio, are shown in Table 2.3.

An important difference between carbon oxide fault gas production and hydrocarbon fault gas production is that in severe cases, where paper insulation is being carbonized by a localized very hot spot, the upward trend in NEI-CO may level off when the damage is so severe that there is not much paper left near the fault to char. By that time, however, a significant rise in CO/CO<sub>2</sub> should have provided warning that something very bad is happening to paper insulation.

It is worth noting that sometimes NEI-CO may start increasing before there is any noticeable increase in NEI-HC. That can mean that there is a fault affecting paper insulation that is just getting started and not yet heating up the nearby oil enough to generate a lot of hydrocarbon gas. Shifts in CO /CO<sub>2</sub> and NEI-CO can provide early warning of faults. They should not be ignored just because NEI-HC isn't changing.

Condition	$CO_2/CO$	CO/CO <sub>2</sub>
Normal aging	Slow increase	Slow decrease
General overheating	Increase	Decrease
Fault outside of windings	Decrease 25-45%	Increase 33-82%
Fault in windings	Big decrease 65%	Big increase 186%+

Table 2.3: Carbon oxide ratio interpretation

#### 2.5.4 Hydrocarbon gas ratios

If a fault or abnormal operating condition is causing fault gas production, the spatial distribution of temperatures or energy intensities associated with the problem – in other words, the fault type – will determine what mixture of hydrocarbon gases will be produced from the oil, and in that mixture which (if any) of the gases will be predominant. Considering the enthalpies of formation of the fault gases (Table 2.4) from oil, the average gas proportions seen corresponding to each fault type, as shown in Figure 2.8, are not surprising.

 Table 2.4: Standard enthalpies of formation (kJ/kL) of fault gases from pyrolysis of insulating materials

Source	Gas	Formula	$\Delta_{\rm f} {\rm H}^{\rm o}$
Oil	Methane	CH₄	77.7
Oil	Ethane	C <sub>2</sub> H <sub>6</sub>	93.5
Oil	Ethylene	C <sub>2</sub> H <sub>4</sub>	104.1
Oil	Hydrogen	H2	128.5
Oil	Acetylene	C <sub>2</sub> H <sub>2</sub>	278.3
Cellulose	Carbon Monoxide	СО	101.4
Cellulose	Carbon Dioxide	CO2	30.2





Fault Type T2





Fault Type D1





Figure 2.8: Average fault gas distribution associated with each major fault type.

One way to understand a hydrocarbon gas ratio such as  $C_2H_4$  / $C_2H_2$  is as a comparison of the amounts of the dominant gases of two fault types: which fault type is more strongly suggested by the available data? The  $C_2H_4$  / $C_2H_2$  ratio, for example, can be seen from **Duval Triangle 1** (Figure 2.9) to be very large for fault type T3 and either close to 1 for D2 or much smaller than 1 for D1.

Another interpretation of a hydrocarbon gas ratio is as a crude way of judging fault temperature. For example, methane is dominant for moderate T1 faults, at about 250°C, and ethylene is dominant for T3 faults, at temperatures over 700°C. The ratio  $C_2H_4$  /CH<sub>4</sub>, then, tells us roughly whether the observed fault gas distribution corresponds to a fault type at the high end or the low end of the temperature range.

Fault Type	Definition
Т3	Thermal, T > 700° C
T2	Thermal, 300° < T < 700° C
T1	Thermal, T < 300° C
PD	Partial discharge
D1	Discharges of low energy
D2	Discharges of high energy
DT	Mixture of discharge and thermal
S	Stray gassing of oil, T < 200°C
0	Overheating, T < 250°C
С	Possible Carbonization of Paper, T > 300°C

Table 2.5: Fault types identifiable by Duval triangles\*

\*Adapted from Table 2.1 of [9]

#### 2.5.5 Hydrogen

The diagnostic use of hydrogen produced from the oil is mainly to distinguish between partial discharge (PD) and a low-range thermal fault (T1). In some cases, such as when T1 is caused by delamination in the core, so much hydrogen is generated that the distinction cannot be made.

Hydrogen can be produced from cellulosic insulation as a byproduct of pyrolysis or hydrolysis, and it can be produced from oil by various chemical reactions involving or catalyzed by oil additives (passivator), galvanized metal, water, and other substances in the transformer. However, since hydrogen is also produced to some degree by all the basic IEC fault types (see Figure 2.8), if a hydrogen-only DGA monitor indicates hydrogen production, it is advisable to investigate.

The C<sub>2</sub>H<sub>2</sub> /H<sub>2</sub> ratio is used to judge whether or not the appearance of acetylene in a transformer's oil really indicates an electrical discharge fault (D1 or D2). As **Figure 2.8** indicates, for D1 and D2 faults in the main tank the acetylene and hydrogen levels are typically similar. IEC 60599 [8] suggests that a C<sub>2</sub>H<sub>2</sub> /H<sub>2</sub> value "higher than 2 to 3" may indicate leakage of tap changer compartment oil into the main tank instead of a D1 or D2 fault. Alternatively – as we continue to harp on the subject of gas loss – there could be an arcing fault, but C<sub>2</sub>H<sub>2</sub> /H<sub>2</sub> is high because hydrogen is being lost, either through a leak or by nitrogen pressure regulation.

#### 2.5.6 Water concentration and relative saturation

Water is found in the transformer in three places. Most of it is absorbed in the paper and pressboard insulation. Some of it is dissolved in the oil or adsorbed on fine carbon and sludge particles suspended in the oil. Sometimes liquid water can be found pooled in the sump at the bottom of the transformer tank.

There are three main reasons for being interested in water with regards to DGA.

- Water can damage cellulosic insulation. With acidic oil oxidation byproducts as catalysts and aided by elevated operating temperatures, water in the oil can attack and decompose cellulosic insulation in a chemical reaction called "acidcatalyzed hydrolysis."
- 2. High or spiking water concentration or relative saturation of water in oil is supporting evidence for high water content of paper insulation, which is often associated with water ingress from a leak.
- 3. Water in oil can drive hydrogen production. Water in the presence of some metals found in transformers can decompose into hydrogen and oxygen.

The water concentration in oil can be measured from a syringe oil sample collected for DGA. The bad news regarding the assessment of water in oil is that the water concentration in oil based on a single manually collected sample is hard to interpret. In an operating transformer whose oil temperature varies with changes in load, sunlight, ambient temperature, and so on, the water content of the oil is seldom in equilibrium with the water in the surface layers of the cellulosic insulation. Because of that, the water concentration in oil can fluctuate, driven by changes in the oil temperature but affected by many other circumstances including the moisture content of the paper insulation and the condition of the oil. If monitored, the relative saturation of water in the oil can also be seen to vary considerably as the transformer goes through its daily temperature cycle. The magnitude of the variation depends on the condition of the oil and the wetness of the thin cellulosic insulation. For details, see [18] or [19].

Another serious problem with laboratory water in oil determination is that the solubility of water in oil increases significantly as the oil oxidizes with age. The relative saturation of water in oil calculated from water in oil concentration using new-oil water solubility coefficients can be greatly exaggerated, unless of course the oil actually is new. Likewise, the relative saturation, measured directly in the oil sample by the lab, is not informative unless it is measured at the same temperature as the sample was at when collected. Finally, water in oil concentration calculated from measured relative saturation using new-oil water saturation solubility coefficients can be greatly understated.

Unfortunately, unless the laboratory is determining the oil's actual water solubility coefficients, any diagnostic use of reported water in oil or relative saturation based on a value determined from a single sample is highly speculative. In general, though, the range of variation of water concentration or relative saturation increases as the paper insulation gets wetter. A large spike in water concentration or relative saturation following a temperature change may indicate excessive water content of the paper insulation.



#### 2.5.7 Fault energy indices

Fault energy indices provide an excellent way to interpret fault gas measurement data to detect and assess active fault gas production. An NEI-HC gassing event is a time period during which the oil has been subjected to enough fault energy to generate hydrocarbon gases. The rate of rise of NEI-HC, especially just before and including the most recent sample in the event, is an indicator of the intensity of the fault. The amount of rise, i.e., the increment of NEI-HC over the entire gassing event, is an indicator of the total fault energy released since the gassing episode began. Similarly, an NEI-CO gassing event is a time period during which paper and pressboard insulation has been subjected to fault energy. It is of great diagnostic interest to know which gas – CO or  $CO_2$  – is primarily responsible for an NEI-CO gassing event, and for that we must look at the ratio of those gases, as discussed in **section 2.5.3** and **Appendix C**.

The gas production increment over a gassing event can be calculated for each hydrocarbon gas by subtracting the initial value from the final value. As discussed below in **section 2.5.8**, those increments can then be used to determine the fault type that appears to be responsible for generating the fault gases during that event.

In some cases, where a fault is affecting paper insulation but during the NEI-CO event not much hydrocarbon gas from the oil has made it into the circulating oil that is being sampled, it is not possible to associate a fault type with the event. That does not mean that there is no fault! Likewise, a severe CO /CO<sub>2</sub> increase could be based on fast carbonization of a small local volume of winding insulation, providing warning of a possibly very serious problem before any NEI event is detected.

#### 2.5.8 Fault type identification

Although for simplicity's sake articles on the various DGA fault type identification methods refer to using gas concentrations for obtaining a fault type diagnosis, it is best whenever possible to use increments of estimated gas production for that purpose instead of gas concentration measurements from a report. There are two reasons for this. First, the gas concentration at any time may include gas that was produced years ago by an unrelated problem, and that will confuse the diagnosis. Second, if the gas concentration measurements have poor repeatability, i.e., have large random variation from one sample to the next, the fault type diagnosis may be thrown off by measurement error [15]. Basing the fault type identification on gas production increments eliminates irrelevant gas by subtracting it out.

Many fault type identification methods have been developed, with various degrees of effectiveness. The Duval triangle method [21] is widely used because it is simple and performs very well. The classic Duval triangle, nowadays called Triangle 1, is illustrated in **Figure 2.9**. It can be used by itself for fault type classification. When the Triangle 1 diagnosis is one of the low-energy fault types PD, T1, or T2, Triangles 4 and 5 (shown in **Figures 2.10 and 2.11** can be used to discriminate between PD and T1 and identify sub-types S and O of T1 and sub-type C of T2. The various fault types identifiable by the triangle method are defined in Table 2.4.

Other fault type identification methods that perform well are the DGA 4-simplex [20] and the Duval pentagon(s) [22]. The DGA 4-Simplex is not yet widely available, so it has not been widely adopted. As shown in [20], the Duval pentagon and other methods based on a pentagon have an unfortunate and incurable geometric flaw causing them to mis-identify fault types in some cases. Evidently, the flaw is not catastrophic, but we have not determined how bad it is for practical purposes.

Gas proportions are used to plot a point in a triangle, and then the indicated fault type is identified by the zone that the point lies in. For example, suppose that 45, 150, and 15  $\mu$ L/L of methane, ethylene, and acetylene respectively are produced during a gassing event. The total of the three is 46 + 138 + 16 = 200  $\mu$ L/L. Each of the produced amounts is divided by the total to obtain proportions 0.23, 0.69, and 0.08. Plotting those proportions on the coordinate grid provided for Triangle 1 locates a point in the T3 zone, so we conclude that the gassing event was caused by a T3 (high temperature thermal) fault. If the plotted point is on or near a fault zone boundary, it is likely that the fault is either a mixed type, such as T2 evolving into T3, or a borderline case, such as a thermal fault averaging close to 700°C.



Figure 2.9: Duval Triangle 1. This is the "classic" Duval triangle for fault type identification in mineral-oil-immersed transformers.



Figure 2.10: Duval Triangle 4. This is the supplementary Duval triangle for identification of low-energy faults in mineral-oil-immersed transformers.





#### 2.5.9 Tea leaf reading

If the transformer has an air leak, fault gas levels and rates of change may be difficult to interpret, and it will be hard to estimate the severity of any fault that may be present. When NEI is trending down, it is necessary to interpret individual fault gases. Use of fault type identification methods is not possible.

When there is evidence of gas loss, a constant or slowly increasing level of a gas while others are zero or declining suggests active gas production, regardless of the actual gas concentration. Gas ratios can be used with caution.

- Example: A transformer has 8000 μL/L of O<sub>2</sub> and an O<sub>2</sub>/N<sub>2</sub> ratio of 0.35. H<sub>2</sub> is zero. CO is steady, and CO<sub>2</sub> is decreasing. Methane and ethane are very low and decreasing. Acetylene is zero. Ethylene has gone from 8 to 9 μL/L. What does this mean? The high oxygen and O<sub>2</sub>/N<sub>2</sub> values with zero H<sub>2</sub> tell us that the transformer seems to be exchanging gases with the atmosphere. Decreasing methane and ethane support that. In order for ethylene to be steady or increase slightly, then, there must be active ethylene production. Likewise, in order for CO (which is very volatile) to be steady, there must be active CO production. The combination of active ethylene and CO production suggests that there could be a T3 fault that is charring paper insulation. Because the rate of gas loss is unknown, there is no basis for estimating relative severity, but the suggestion of T3 with paper charring could motivate some serious investigation and arrangements for a possible outage.
- Example: A transformer has high O<sub>2</sub> and O<sub>2</sub>/N<sub>2</sub>. Combustible gases are all declining or zero, except H<sub>2</sub> at 30 µL/L is steady or declining just a little bit. What does this mean? The transformer is leaking air and losing fault gas, but the most volatile gas, hydrogen, is not decreasing rapidly as would be expected. Therefore we must suspect that there is significant hydrogen production going on. Total absence of any acetylene would allow us to hope that this is a PD or T1 problem. Presence of any acetylene in spite of gas loss would suggest that there may be D1 or D2 happening. In either case, we have to suspect that something is not right, and the transformer must be investigated.

### DGA risk assessment

#### 3.1 Transformer health versus DGA risk assessment

A transformer's gassing status (relating to the Fundamental Principle of DGA stated earlier) can be coded as levels 1 to 3:

- Level 1: Never has produced fault gas.
- Level 2: Produced fault-related gas in the past but is not currently doing so.
- Level 3: Is currently producing fault-related gas.

The rate (low or extreme) of recent fault gas production, apparent fault type, and hazard factors HF-HC and HF-CO as discussed in Appendix D can be used to compare gassing transformers to decide which ones should be subjected to investigation or intervention and in what order of priority. The hazard factors are predictive in nature and suitable for assessment of relative risk of failure, but not for condition assessment. DGA provides only general information, for example "there is hot metal in contact with oil" or "there is sparking somewhere" or "some cellulosic material somewhere is being carbonized." Although those conditions are undesirable, specific information about whether the hot metal, sparking, or charring is affecting the transformer's suitability for continued service must usually be obtained by electrical and physical testing, not from DGA results alone.

Test results such as turns ratio, DC winding resistance, and insulation power factor provide direct provide information about the transformer's condition. DGA is based on a symptom – fault gas production – and only provides a warning, like a pain or a cough, that the condition seems abnormal in some way. For that reason it is not appropriate to include DGA results in a "health index," for example, other than as an indication that the transformer does or does not seem to require investigation.



#### 3.2 Assign relative risk scores

Annex F of [7] provides a good summary of a basic approach to DGA risk assessment using NEI. Here we describe a version of that approach employing a numeric risk assessment based on the survival probability models of NEI-HC and NEI-CO discussed in **Appendix D**.

Roughly speaking, The amount of fault gas (or the magnitude of a fault energy index, NEI) in a transformer indicates how much of a headache the transformer has been in the past. According to the Fundamental Principle of DGA, it is active fault gas production that tells us that the transformer is in difficulty, and the rate of gas production expressed in terms of NEI-HC and NEI-CO can be used to calculate hazard factors HF-HC and HF-CO (as discussed in Appendix D) to assess the relative level of risk of a near-term forced outage should the gassing continue.

For purposes involving expense considerations, such as prioritizing transformers for maintenance or worrying about cost of replacement, the hazard factors can be multiplied by a cost, such as replacement cost or cost of cleaning up a catastrophic failure, to obtain an actual risk number for ranking transformers in a fleet. If money costs are not known, the transformer's highest MVA rating is a reasonable indicator of its relative importance and can be used as a multiplier for risk. Similarly, the transformer's oil capacity is a rough indicator of potential cleanup or fire damage cost in the event of a catastrophic failure.

#### Example

The case history discussed in [23] illustrates how the recent advances in DGA discussed in this guide work together to provide early warning of an internal problem that was not noticed by conventional DGA at the time and ultimately failed the transformer.

A 250 MVA, 230 kV nitrogen-blanketed transformer manufactured in the early 1980s had unexceptional fault gas levels, except for a persistently high CO<sub>2</sub> concentration of about 4200  $\mu$ L/L, as shown in Figures 3.1 and 3.2, taken from the paper [23]. It is fair to say that an astute observer, realizing that the transformer was losing gas due to nitrogen pressure regulation, by tea leaf reading as described in Section 2.5.9 might have noticed in 2001-2003 and 2008-2009 that there were signs of a possible thermal fault affecting paper insulation. Unfortunately, since no IEEE C57.104 hydrocarbon or hydrogen gas concentration limits were exceeded, the signs were not noticed, and the transformer went on to fail in service in early 2011.



Figure 3.1: Hydrogen and hydrocarbon gas concentrations. Note that a logarithmic scale is used to permit plotting multiple gases.

The gassing event charts in **Figures 3.3** and **3.4**, based on estimated gas production and NEI, show long upward trends in both NEI-HC and NEI-CO with notable gassing events indicated by numbered colored boxes. In particular, the carbon oxide event #4 from 2001 to 2007 could have been noticed and followed up by investigation. Surely the 2007-2009 hydrocarbon gas event #5 latterly overlapping with carbon oxide gas event #6 would have been taken seriously.

Unfortunately, with gas loss the estimated gas production can only underestimate the risk of near-term failure. The combined hazard factor at the beginning of 2010 was only about 0.18 percent per year, which would have placed the transformer on the list of suspect transformers, but possibly not near the top. That illustrates the point that one should not rely on numerical or statistical indicators of risk without taking into consideration relevant qualitative information such as the fact of gas loss.



Figure 3.2: Atmospheric and carbon oxide gas concentrations. Note that a logarithmic scale is used to permit plotting multiple gases.



**Figure 3.3**: Hydrocarbon gas NEI (NEI-HC) with significant gassing event indicated by box. Dotted graph shows what would be seen without using estimated gas production.



Figure 3.4: Carbon oxide gas NEI (NEI-CO), with significant gassing events indicated by boxes Dotted graph shows what would be seen without using estimated gas production.



# Appendix A – Common transformer faults

W. H. Bartley classified 96 transformer failures according to cause in Table 3 of a 2003 conference paper [23], summarized here in Table A.1.

Table A.1: Causes of transformer failures

Cause of failure	Number
Insulation failure	24
Design/material/workmanship	22
Unknown	15
Oil contamination	4
Overloading	5
Fire/explosion	3
Line surge	4
Improper maintenance/operation	5
Flood	2
Loose connection	6
Lightning	3
Moisture	1

The above listed causes of failure are not mutually exclusive – for example, a line surge could cause insulation failure in a transformer with defective insulation. It may be helpful to consider a few examples of faults that can lead to failure. They are listed in no particular order.

Table A.2: Common transformer faults

Fault
Leaks - air leaks, leaking LTC compartment, oil leaks
Disconnected or inoperative cooling fan
Rusty, clogged, or blocked radiator
Faulty or inoperative cooling pump
Loose lead connection
Coked NLTC contact
Hot bushing
Turn-to-turn short
Core grounding problem
Core de-lamination
Circulating currents in metal parts
Torn or leaking conservator diaphragm
Phase-to-ground short
Loose blocking, distorted windings
Corona discharge on metal component
Corona discharge in gas or water vapor bubble
Sparking between metal parts

### Appendix B – Fault energy indices

**Table B.1:** Standard enthalpies of formation (kJ/mol) of fault gases from pyrolysis ofinsulating materials.

Source	Gas	Formula	$\Delta_{\rm f} {\rm H}^{\rm o}$
Oil	Methane	CH4	77.7
Oil	Ethane	C <sub>2</sub> H <sub>6</sub>	93.5
Oil	Ethylene	C <sub>2</sub> H <sub>4</sub>	104.1
Oil	Hydrogen	H2	128.5
Oil	Acetylene	C <sub>2</sub> H <sub>2</sub>	278.3
Cellulose	Carbon Monoxide	СО	101.4
Cellulose	Carbon Dioxide	CO2	30.2

For each fault gas <sub>g</sub> define the normalized energy intensity NEIG for that gas like this:

 $NEI_G = 1000 \cdot [G] \cdot \Delta_f H^o(G)$ 

where the name of the gas in brackets denotes the concentration of that gas in mol/L, and  $\Delta_r H^o(G)$  is the standard heat of formation (kJ/mol) of *G* from the insulating material from which it is derived. The factor of 1000 is a conversion factor to change the mol/L gas concentrations to SI units of mol·m<sup>-3</sup>, which is equivalent to mol/kL. The units for NEI<sub>G</sub> are thus kJ/kL. Now NEI<sub>M</sub> for a mixture *M* of dissolved fault gases can be defined as:

 $NEI_M = \sum_{G in M} NEI_G.$  (B.2)

(**B**.1)

To convert a gas concentration c expressed in  $\mu$ L/L to mol/L, divide by one million and divide again by the standard molar gas volume  $V^{\circ}$  (L/mol) at the standard temperature and pressure at which the gas concentration is reported. For example, if the reporting conditions are 273.15 K and 101.325 kPa, the standard molar gas volume is 22.4 L/mol. Then the molar concentration of the gas is [*G*] =  $c/(22.4 \cdot 10^6)$ .

 $\text{NEI}_{\scriptscriptstyle G}$  can be expressed in terms of  $\mu L/L$  gas concentrations like this:

$$NEI_G = 1000 \cdot [G] \cdot \Delta_f H^o(G)$$
  
=  $10^3 \cdot \frac{c}{22.4 \cdot 10^6} \cdot \Delta_f H^o(G)$   
=  $\frac{c \cdot \Delta_f H^o(G)}{22400}$  (B.3)

NEI for a mixture M of gases generated from the specified insulating material is calculated like this when the gas concentrations are expressed in units of  $\mu$ L/L at standard temperature and pressure with standard molar gas volume V<sup>o</sup>.

$$\operatorname{NEI}_{M} = \sum_{G \text{ in } M} \operatorname{NEI}_{G}$$
$$= \frac{1}{1000V^{o}} \sum_{G \text{ in } M} c_{G} \cdot \Delta_{f} H^{o}(G)$$
(B.4)

The hydrocarbon gas normalized energy intensity (NEI-HC), as the sum of heats of formation of the four low molecular weight hydrocarbon gases, weighted by fault gas concentrations, was introduced as NEI in [16], defined as follows:

NEI-HC = 
$$\frac{77.7 (CH_4) + 93.5 (C_2H_6) + 104.1 (C_2H_4) + 278.3 (C_2H_2)}{22400}$$
(B.5)

The parenthesized gas names denote dissolved-gas concentrations ( $\mu$ L/L) in mineral oil, measured in the same sample and expressed at standard temperature and pressure conditions of 273.15 K and 101.325 kPa as specified in ASTM D3612 [1]. The numeric coefficients of the gas concentrations in the formulas are the respective standard enthalpies of formation (kJ/mol), from n-octane (C<sub>8</sub>H<sub>16</sub>, a model for a typical mineral oil molecule) for the hydrocarbon gases (See Table B.1).

The Duval triangle gas normalized energy intensity (NEI-T) is defined as NEI for the "Duval triangle gases" methane, ethylene, and acetylene, in the sense of (B.2). If the gas concentrations are measured and reported in  $\mu$ L/L according to ASTM D3612, the formula is as follows.

NEI-T = 
$$\frac{77.7 (CH_4) + 104.1 (C_2H_4) + 278.3 (C_2H_2)}{22400}$$
(B.6)

The carbon oxide gas normalized energy intensity (NEI-CO) is defined as NEI for the carbon oxide gases CO and CO<sub>2</sub>, with standard heats of formation from cellulose (C<sub>6</sub>H<sub>12</sub>O<sub>6</sub>, a model for the monomer of cellulose - see **Table B.1**), calculated as shown in (B.2). If the gas concentrations are measured and reported in  $\mu$ L/L according to ASTM D3612, the formula is as follows.

NEI-CO = 
$$\frac{101.4 (CO) + 30.2 (CO_2)}{22400}$$
 (B.7)

In situations where all of the gas concentrations required for both NEI-HC and NEI-CO are provided, NEI-HC is used for assessment of faults affecting the insulating oil, and NEI-CO is used for the assessment of faults affecting the solid (cellulosic) insulation.

NEI-T is used instead of NEI-HC for transformers that are suspected of ethane "stray gassing," i.e., production of excessive amounts of ethane gas under moderate operating temperatures where no abnormality is suspected. In those cases, NEI-T is used for assessment of faults affecting the insulating oil, and NEI-CO is used for the assessment of faults affecting the solid (cellulosic) insulation.

NEI-T is also used instead of NEI-HC when the source of gas analysis data is an online gas monitor that measures the concentrations of methane, ethylene, and acetylene but not ethane.

It was shown in [16] that hydrocarbon gas NEI is suitable for trending of fault gas generation from transformer oil and for fault severity assessment. One major advantage over trending and assessing individual gases is the reduction in complexity resulting from a reduction of the number of variables. The application of reliability statistics to NEI-HC [24] confirms that NEI is very suitable for fault severity assessment and is not biased for high or low energy fault types.

NEI-CO can be used only when the concentrations of both carbon monoxide and carbon dioxide are being measured.

### Appendix C – Carbon oxide gas ratio

Interpretation of the CO/CO<sub>2</sub> ratio is based on the relative increment of the ratio during a carbon oxide gassing trend, calculated as:

$$dr = \frac{r_1 - r_0}{r_0}$$
(C.1)

where  $r_0$  is the nonzero ratio value at the beginning of the trend,  $r_1$  is the ratio value at the end of the trend, and dr is the relative increment. Note that 100 times dr is the relative increment expressed as percent. For example, if the ratio goes from 0.2 to 0.3, that would be a 50% increase:

$$\frac{0.3 - 0.2}{0.2} = \frac{0.1}{0.2} = 0.5 \tag{C.2}$$

If the ratio goes from 0.2 to 0.5, that would be a 150% increase:

$$\frac{0.5 - 0.2}{0.2} = \frac{0.3}{0.2} = 1.5$$
(C.3)

The relative increment of the CO/CO<sub>2</sub> ratio during a gassing trend, especially during an NEI-CO trend, can provide an indication of the location of a fault affecting paper insulation. An increase in the CO/CO<sub>2</sub> ratio by 33% to 100% suggests local deterioration of paper insulation, such as on a hot bushing or NLTC lead. A very large increase – 185% or more – may indicate deterioration of paper insulation inside the windings or in some confined space. The meaning of an increase between those two ranges is unclear.

A plausible explanation of why the CO/CO<sub>2</sub> ratio tends to increase more for faults in winding paper insulation than for faults outside of the windings is as follows. In accordance with Le Chatelier's principle [25] and general suppositions about how pyrolysis (decomposition by heating) of paper insulation plays out [26], the balance between rates of formation of CO and CO<sub>2</sub> is affected by the relative availability of oxygen in the oil where the paper is being overheated. Inside the windings, where a large quantity of oil-saturated paper is tightly packed, oxygen tends to be depleted by slow oxidation of paper, oil, and dissolved combustible gases. Outside the windings there is circulating bulk oil that usually contains some dissolved oxygen. Correspondingly, pyrolysis of paper insulation deep in the windings or in any confined space takes place in a relatively oxygen-poor environment and thus tends to favor the production of CO over CO<sub>2</sub>. Pyrolysis of paper insulation on conductors outside the windings (such as bushing and NLTC leads) occurs in a relatively oxygen-rich environment, where the reaction is able to produce more CO<sub>2</sub>. Remarkably, the rule for the interpretation of relative increases in the carbon oxide gas ratio applies when gas loss is involved, even when one or both of the gas concentrations is decreasing. An oversimplified explanation for that is as follows.

The respective Ostwald coefficients (at 20°C) for  $CO_2$  and CO in transformer oil are 1.10 and 0.125 according to Table 1 of [29]. At 70°C they are, respectively, 1.02 and 0.12 according to [2] Table 3. Since CO is much less soluble in oil than  $CO_2$  at all operating temperatures, gas loss from the gas space and consequent re-balancing of the concentrations of dissolved and free gas reduces the CO concentration in oil by a greater percentage than the  $CO_2$  concentration.

It follows that an increase of the  $CO/CO_2$  ratio in the presence of sudden or gradual gas loss implies that there must be active production of CO at a rate much higher than that of  $CO_2$  in order to reverse the decrease in the ratio that would be expected due to preferential loss of CO if there were little or no production of that gas.

# Appendix D – DGA reliability models

The statistical modeling of mortality and equipment failure, sometimes called time to event analysis or survival analysis, is a well established branch of statistics that is very important to the life insurance industry, to medical science, and to reliability engineering [28].

A statistical model of transformer service lifetime such as shown in **Figure D.1** can be derived by tabulating the ages of transformers still in service as well as the ages of transformers at the time that they were removed from service. Although it may not be obvious at first why the ages of transformers still in service would be needed for deriving a model of age at end of life, the explanation is that those contribute by constraining the distribution of end of-life age – at least so much of the population is still in service at age 60, and so on. The cases where the transformer has not been removed from service yet and so has an unknown lifespan are called "censored" by statisticians, while the observed final ages are called "uncensored." Naively trying to construct a time to event model without including censored cases usually leads to incorrect models.

Survival models often represent time to a certain kind of event such as death, relapse, equipment failure, radioactive decay of atoms, and so on. In some applications the "time" variable is not actual elapsed time but an operations count value, volume of fuel consumed, or some other quantity that can be assumed to be increasing until the relevant kind of event is observed.

For DGA we are interested not so much in age at end of life, but rather in how far the gassing of a faulty transformer might go before forced outage. The NEI or gas concentration values used for developing a DGA survival model (Figure D.2) are based on estimated fault gas production as described in section 2.4.1. To construct such a model for NEI-HC, we tabulate:

a) the latest in-service level of NEI-HC production observed in each gassing transformer that has not failed (censored cases), as well as;

b) the latest in-service level of NEI-HC production observed in gassing transformers that were forced offline due to an internal problem (uncensored cases).





Comparing the survival probability curves for transformer service life (Figure D.1) and NEI-HC gassing (Figure D.2), it is apparent, from the sharp downward trend of the NEI-HC survival curve for small values of NEI-HC versus the almost horizontal trend of the curve for young service age, that starting to produce hydrocarbon gas is much more hazardous than getting older.

For a simple use of the NEI-HC survival model for risk assessment, we note that the part of the curve from NEI-HC = 0 to NEI-HC = 6 (which is close to the 95th percentile of NEI-HC in our large database) is nearly linear with a slope of -0.018 per kJ/kL unit. That is, in this NEI-HC range 1.8 percent of gassing transformer transformers fail before producing one more unit of NEI-HC. That is, the average hazard rate for NEI-HC gassing is 1.8 percent per NEI unit. If we know how fast (in NEI units per year) the transformer is gassing, say for example 2.5 kJ/kL of NEI-HC per year, we can multiply the rate of increase by the hazard rate to obtain what we call a hazard factor value of 2.5 units/year x 1.8 percent/unit = 4.5 percent per year, which we can use as a relative risk factor for comparing that transformer with others.



Figure D.2: Survival probability curve for NEI-HC.

The survival probability curve for NEI-CO (not shown) has a similar shape to the NEI-HC one, but it is shallower. The average downward slope for NEI-CO between 0 and 20 (its approximate 95th percentile) is 0.0035 per kJ/kL unit, or an average hazard rate of 0.35 percent per additional unit of NEI-CO. That can likewise be multiplied by the rate of increase of NEI-CO for an individual transformer to obtain a hazard factor (relative risk factor) based on deterioration of paper insulation.

DGA survival models are introduced and discussed in [24].

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# Definitions

**Common carbon oxide gases:** The common carbon oxide gases are carbon monoxide (CO) and carbon dioxide (CO<sub>2</sub>). There are many other carbon oxides, but they are irrelevant for DGA.

**Dissolved-gas analysis (DGA):** Dissolved-gas analysis is the measurement and interpretation of dissolved-gas concentrations in the insulating liquid of an electric power apparatus, especially a power transformer.

**DGA observation:** A DGA observation is a dated and time-stamped collection of gas concentration measurement values obtained simultaneously by analysis of an oil sample according to a standard measurement procedure, such as ASTM D3612 [1] or IEC 60567 [2], or alternatively by an automated process controlled by the firmware of a portable gas analyzer or an online gas monitor.

**DPOA:** A DPOA item is a quantity or assertion that is extracted from a dark part of the anatomy.

**Failure:** A transformer fails when it ceases to perform its intended and specified function while energized. For example, internal insulation fails to prevent a short circuit between turns of a winding, or the cooling system fails to prevent runaway overheating. Usually an internal failure results in a forced outage, i.e., the transformer trips offline, is taken offline by an operator, or suffers catastrophic damage.

**Fault:** A fault in a transformer is an internal condition that is inconsistent with intended or specified operating conditions, such as for example local or general overheating, arcing, or partial discharge. This usage must not be confused with fault in reference to an abnormal voltage or current in the circuit to which the transformer is connected.

**Fault energy index:** A fault energy index is normalized energy intensity (NEI) as a weighted sum of gas standard enthalpies of formation, where the weights are respective gas concentrations from a DGA observation. The gases included in a fault energy index must be degradation products attributed to either the liquid or the solid insulation, but not to both. The standard enthalpies of formation are for gas generation from the relevant insulating material by a specified reaction such as pyrolysis.

**Fault gases:** Fault gases are formed by the exposure of insulating materials to abnormal conditions – high temperatures, sparking or arcing, or corona discharge – in a transformer. The fault gases of most concern for DGA are hydrogen, the common carbon oxide gases, and the low molecular weight hydrocarbon gases.

**Gas ratio**: A gas ratio is the ratio of two gas concentrations in the same medium (oil or gas) at the same time. For some purposes, such as fault type identification, a gas ratio can be the ratio of the increments of two gas concentrations over some specified time interval. The customary informal notation for gas ratios in DGA related contexts uses chemical formulas such as, for example,  $O_2 / N_2$  for the oxygen/nitrogen ratio. The chemistry notation is  $[O_2] / [N_2]$ , where  $[O_2]$  and  $[N_2]$  denote the molar concentrations (mol/L) of the gases. **Gassing trend:** A gassing trend is an increasing sequence of consecutive gas concentration or fault energy index observations  $< x_1, x_2, \ldots, x_n >$ .

**Hydrocarbon gases**: Gases whose molecules contain only hydrogen and carbon. The low molecular weight hydrocarbon gases of interest in DGA are methane (CH<sub>4</sub>), ethane (C<sub>2</sub>H<sub>6</sub>), ethylene (C<sub>2</sub>H<sub>4</sub>), and acetylene (C<sub>2</sub>H<sub>2</sub>).

**Increment:** The increment of a quantity *x* whose value changes from  $x_0$  to  $x_1$  is  $x_1 - x_0$ , which is also called delta-*x* ( $\Delta x$ ). (See also: Relative increment).

**LTC:** An LTC is an on-load tap changer, i.e., a tap changer whose tap selector position can be changed when the transformer is under load.

**NLTC:** An NLTC is a no-load tap changer, i.e., a tap changer whose tap selector position is not intended to change while the transformer is under load.

**Oil sample:** An oil sample is a physical sample of oil drawn from a transformer according to a prescribed method (or by an automated process).

Power transformer: A power transformer is a transformer with a maximum power rating of at least 500 kVA.

Principal atmospheric gases: The principal atmospheric gases are oxygen (O<sub>2</sub>) and nitrogen (N<sub>2</sub>).

**Relative increment:** The relative increment of a quantity *x* whose value changes from  $x_0$  to  $x_1$  is  $(x_1 - x_0)/x_0$ , provided that  $x_0 \neq 0$ . (See also: Increment).

**Sample date:** The local date or date and time when an oil sample was drawn is the sample date of that sample. "Earlier" and "later" in relation to oil samples or their DGA observations reference the respective sample dates.

**Standard enthalpy of formation:** The standard enthalpy of formation of a gas from an insulating material is the amount of energy required to form one mole of the gas from that insulating material at standard pressure and temperature. The units are kilojoules per mole (kJ/mol). The standard pressure and temperature are specified by the measurement procedure by which the gas concentrations are obtained.



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