296

RECENT DEVELOPMENTS IN DGA INTREPRETATION

Joint Task Force
D1.01/A2.11

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Note : superscripts in this report (e.g, [a]) refer to members or other experts who made specific contributions to the report (unpublished data or concepts). The list of superscripts and corresponding authors can be found on page 20 of the report, after the References

CONTENTS

1-INTRODUCTION

Dissolved gas analysis (DGA) is widely used for monitoring faults in insulating fluid-filled, high-voltage electrical equipment in service. New DGA laboratory extraction techniques have been evaluated by CIGRE TF 15-01-07 [1] and introduced into revised IEC Publication 60567 [2]. The interpretation of DGA results has been deeply revised in 1999 in IEC Publication 60599 [3].
The diagnosis methods used for the identification of faults are widely accepted. However, the typical gas concentration values and rates of increase observed in service and reported in 60599 (for mineral insulating oils) by IEC TC10 have been questioned by IEC TC14 (transformers). This has prompted the corresponding committees of CIGRE SC A2 (ex SC12) and SC D1 (ex SC15) to create in 2001 a joint task force (TF 15/12-01-11, or “TF11”) to clarify this issue. TF11 was also given the task to examine other aspects of DGA interpretation which needed clarifications or improvements, such as the formation of gases from stray gassing oils, partial discharges and paper insulation.

2-GAS LEVELS IN SERVICE

2.1-ABBREVIATIONS

TGC : Typical Gas Concentration
TRGI : Typical Rate of Gas Increase
PFS : Probability of a Failure-related event in Service
PFGC : Pre-Failure Gas Concentration
PFRGI : Pre-Failure Rate of Gas Increase
AGC : Alarm Gas Concentration
ARGI : Alarm Rate of Gas Increase

The definitions of these gas levels in service, derived from IEC 60599, are given in following sections 2.2 to 2.4.

2.2-TYPICAL VALUES

Typical (TGC or TRGI) values are the calculated values typical of what is observed in a given portion (e.g., 90%) of a population of transformers in service.

IEC 60599 recommends users to calculate gas ratios and propose fault diagnoses only when gas concentration levels and rates of gas increase in service are above 90 % typical values. The reasons for this recommendation are mostly practical : to avoid spending too much maintenance money on the lower 90 % of DGA cases where faults are less likely to occur, and to focus monitoring efforts on the upper 10 % of cases where the probability of a fault in service is higher. Furthermore, below typical values, gas concentrations may be too close to detection limits, leading to inaccurate gas ratios.

It is also recommended in IEC 60599 that each network calculates its own typical values, since these are dependent on the specific equipment and operating conditions used. By default, ranges of typical gas concentration (TGC) values observed in various countries worldwide are indicated in 60599, for power transformers with and without a communicating OLTC (Table 1), instrument transformers, bushings and cables. In 1999, IEC TC14 objected to the values for power transformers, and proposed dramatically higher values (Table 2).

Table 1 : Ranges of 90 % typical (TGC) values of IEC 60599 for power transformers, in ppm

	C2H2	H2	CH4	C2H4	C2H6	CO	CO2
No OLTC	3-50	60-150	40-110	60-280	50-90	540-900	5100-13000
Communicating OLTC	80-270	75-150	35-130	110-250	50-70	400-850	5300-12000

Table 2 : 90 % TGC values proposed by IEC TC14 for power transformers, in ppm

	C2H2	H2	CH4	C2H4	C2H6	CO	CO2
All transformers	200	500	350	500	800	1000	14000

IEC TC10 therefore asked TF11 to organize an independent survey of TGC values observed by its members. These are indicated in Table 3, together with explanatory notes.

Table 3 : Ranges of 90 % typical (TGC) values surveyed by TF11 for power transformers [a,m,p,f,e,d,b,q] , in ppm

	C2H2	H2	CH4	C2H4	C2H6	CO	CO2
All transformers		50-150	30-130	60-280	20-90	400-600	3800-14000
No OLTC	2-20						
Communicating OLTC	60-280						

Explanatory Notes [a] **:**

1) 90% typical values are cumulative percentile values, i.e., 90% of DGA values observed in service are below typical values, and 10% are above, for the power transformer populations examined in the CIGRE SC D1 and SC A2 surveys.
2) About 25 electrical networks worldwide were surveyed. Each provided an individual average typical value for each gas. The ranges of values indicated in the Table for each gas therefore actually contain about 25 individual values. The relatively large ranges of values reported are an indication of the differences in operation practices of the individual networks (average transformer age, use of air-breathing or sealed equipment, transformer manufacturers, loading practices, number of OLTC operations, maintenance procedures).
3) Values in the Table have been reported mostly from core-type transformers. Values in shell-type transformers are likely to be higher [b] (Table 7). In two countries [d] , values for C2H6 are higher. In one country where transformers are operated below nominal load, values for CH4 and CO and particularly C2H4 are lower [u,v].
4) Values from frequently degassed transformers, and with reconditioned or reclaimed oil, have not, and should not be added to this Table [m]. Frequent degassing is practiced only in a few countries.
5) Due to chemical reactions between oil and components of an unused transformer, some differences in H2 concentrations may occur [l]
6) Values on other individual networks may be outside the ranges indicated in the Table.
7) All transformer users are strongly recommended to calculate their own typical values, specific to their own transformer populations, using methods indicated in IEC 60599 and in this paper.
8) For transformers with DGA contents above typical values (in the upper 10% percentile of the population), the only action recommended in IEC 60599 is to increase the frequency of DGA analyses.

In addition, TF11 proposed the calculation of 90 % typical values for rates of gas increase (TRGI values, in ppm/ year) , a new concept [a] which is not included in IEC 60599 and allows the comparison of values from different networks. These are indicated in Table 4, together with explanatory notes.

Table 4: Ranges of 90 % typical rates of gas increase (TRGI) surveyed by CIGRE TF11 for power transformers, in ppm/year [a,b,d,e]

	C2H2	H2	CH4	C2H4	C2H6	CO	CO2
All transformers		35-132	10-120	32-146	5-90	260-1060	1700-10,000
No OLTC	0-4						
Communicating OLTC	21-37						

Explanatory Notes [a,b,d,e,q] :

1) Notes given for Table 3 also apply to Table 4 except for Note 2) where "about 25" should be replaced by "4".
2) TRGI values in Table 2 are valid for large power transformers with an oil volume > 5000 litres. They have been measured in ppm/year (µl/l/year) by CIGRE TF11 members. They can be converted into ml/day when the oil volume of the transformer is known.
3) TRGI values in small transformers (< 5000 litres) are usually lower than in Table 4
4) TRGI values in the early and late years of the equipment tend to be higher than the average values given in Table 4.
5) When calculating TRGI values, DGA intervals should be chosen to provide an acceptable accuracy of results.
6) Values in Table 4 should not be used to calculate concentration values after several years and compare them to values in Table 3, since values in these two tables are affected differently by the shape of their respective cumulative curves and gas losses.

Values in Tables 3 and 4 have been submitted to, and approved by IEC TC10 and IEC TC14.

2.3-CALCULATION OF TYPICAL VALUES

To calculate TGC and TRGI values [a,e], separate from the DGA data bank the analyses related to the population of transformers to be evaluated (for instance, power transformers without a communicating tap changer).

For TGC values, for each gas, list the concentrations by increasing order of values. Calculate the 90% percentile number of analyses in the list. The corresponding concentration value represents the 90% TGC value in ppm for this gas and this transformer population.

For TRGI values, for each individual transformer in this population and each gas, calculate the difference between 2 successive DGA analyses, in terms of gas concentrations (in ppm) and time (in fractions of year). The ratio of these 2 terms gives the rate of gas increase in ppm/year. Repeat the same procedure for all analyses and transformers in the selected data bank. List the results by increasing order of values. Calculate the 90% percentile number of analyses in the list. The corresponding value of rate of increase represent the 90% typical rate of gas increase (TRGI) in ppm/ year for this gas and this transformer population.

Note : to perform these calculations, it is convenient to convert the DGA data bank to Excel format. For rates of increase, dates should be entered in such a way that differences are expressed in fractions of year. The first analysis performed on a transformer, and the transformers where only one analysis was performed provide values divided by 0 which are rejected by the computer and can thus be easily eliminated.

2.4-INFLUENCE OF VARIOUS PARAMETERS ON TYPICAL VALUES

Several parameters may affect typical values, which explains the ranges of values observed in Tables 3 and 4 by different networks and countries : the type of equipment (power or instrument transformers, transmission or generation power transformers), sub-type (core, shell, shunt), manufacturer, voltage, age, size ; the operating conditions (load, climate) ; the type of oil used ; the nature of the faults and the involvement or not of paper.

2.4.1-Oil volume

This parameter was among the first to be examined by TF11, since many DGA users prefer to use rates of gas increase in ml/day rather than in ppm/ year (or day), with the assumption that the latter unit is dependant on oil volume, while the former is not. Results are indicated in Table 5 in ppm/ year and Table 6 in ml/ day.

Table 5 : 90% TRGI values for power transformers without an OLTC, in ppm/year [a,e]

Oil volume in litres x 10^3	C2H2	H2	CH4	C2H4	C2H6	CO	CO2	Number of analyses
< 5	0.4	6	1.5	2.8	1	70	430	3011
5- 20	1.7	113	28	48	20	540	6720	2497
20-50	0.7	52	14	33	9	590	4500	6219
> 50	1.5	75	49	146	38	1060	6870	7643
All volumes*	1	52	18	50	13	650	4720	17,709

*corresponding to an average, weighted oil volume of 40,000 litres

Table 6 : 90% TRGI values for power transformers without an OLTC, in ml/day [a,e] :

Oil volume in litres x 10^3	C2H2	H2	CH4	C2H4	C2H6	CO	CO2	Number of analyses
< 5	0.003	0.04	0.01	0.02	0.007	0.5	3	3011
5- 20	0.06	4	1	1.5	0.7	18	230	2497
20-50	0.07	5	1.3	3	0.9	56	430	6219
> 50	0.3	15	10	30	8	220	1410	7643
All volumes*	0.1	6	2	5	1.5	70	520	17.709

* using an average, weighted oil volume of 40,000 litres

It appears that TRGI values actually are much less dependant on oil volume when expressed in ppm/ year. This suggests that smaller amounts of gases (and smaller faults) are formed in smaller transformers, contrary to the assumption (by proponents of ml/day) that the same volumes of faults and gases are formed in small and large equipment. Results as a function of oil volume for different networks are indicated in Annex A, Table A1.

2.4.2-Equipment age

It is generally assumed that the older the transformer, the more susceptible it is to faults in service and to gas formation. One would therefore expect higher TGC and TRGI values.

Actual values surveyed by TF11 are indicated in Annex A, Table A2 (for power transformers without a communicating OLTC) and Table A3 (with an OLTC). It appears that TRGI values are in general much higher in the early years (< 5) of operation of the equipment. In some networks, but not all, they may also be higher in their very late years (> 40). Since the failure rate is not significantly higher in the early years, this suggests that some unstable chemical bonds in the paper or oil insulation are broken in the early years, then the remaining ones are more stable afterwards.

2.4.3-Equipment type and sub-type

In power transformers, the influence of an OLTC communicating with the main tank of power transformers is indicated in Tables 3-4, and results mostly in higher levels of C2H2. Voltage has a relatively minor influence [a,b], and remains within the ranges of values of Table 3.

It was found that TGC values in sealed or nitrogen-blanketed power transformers are within the ranges of values of Table 3 [p] (contrary to the often heard assumption that they are lower in such equipment). The proportion of sealed vs. breathing power transformers in different countries is indicated in Annex A, Table A4.

Power transformers of the shell-type or shunt reactors produce markedly higher levels of hydrocarbons (except C2H2), as indicated in Table 7 (compare with values in Table 3). A tentative explanation for this higher gas formation might be that these transformers operate at higher temperatures. Relatively few of them are in use worldwide, however.

Table 7 : 90 % TGC values in shell-type power transformers and shunt reactors, in ppm

	C2H2	H2	CH4	C2H4	C2H6	CO	CO2	Number of analyses
Shell-type, no OLTC [d]	13	51	169	241	1109	530	4579	632
Shell-type, OLTC [d]	289	506	236	434	940	892	8676	339
Shunt reactors [f]	5	85	271	383	94	884	3537	119

In instrument transformers, TGC and TRGI values are in general much lower than in power transformers, as indicated in Table 8.

Table 8: 90% TGC and TRGI values for instrument transformers [b,e,a]

		C2H2	H2	CH4	C2H4	C2H6	CO	CO2	Number of analyses
TGC	ppm	0-2	16-115	4-19	1-14	2-16	350-450	1,400-2,100	9798
TRGI	ppm/ year	0.3-1	5-12	2-3	1-2	2-3	53-59	200-235	9602

2.4.4-Fault type

DGA values on average are higher in the case of thermal faults (except for C2H2), as indicated in Table 9, corresponding to power transformers without an OLTC.

Table 9 : 90 % TGC values, in ppm, vs. fault type [a]

Fault type	H_2	C_2H_4	C_2H_2
Electrical	85	35	70
Thermal	175	375	3

DGA values are also slightly higher for faults in oil than for faults in paper (Table 10). Values in Table 10, also corresponding to power transformers without an OLTC, were obtained by separating from the DGA data bank the cases clearly indicating paper involvement, based on a CO2 to CO ratio < 3.

Table 10 : 90% TGC values, in ppm,
vs. fault location [a]

Fault location	H_2	CH_4	C_2H_6	C_2H_4	C_2H_2
Oil	77	70	42	153	5
Paper	70	50	40	60	5

2.5-PRE-FAILURE AND ALARM VALUES

In some DGA data banks [a], it is indicated when the gas analysis corresponds to a failure-related event (tripping of the equipment, fault-related gas alarm, tank rupture, fire or explosion). Using such data banks, the probability of having a failure-related event in service (PFS) can be defined and calculated as the ratio between the number of DGA cases followed by such an event, to the total number of analyses, at different gas concentrations.

Note : in these data banks, oil samples were taken from the bottom of the tank shortly before or immediately after the event. While the gas content of the top oil is strongly and rapidly affected by the event, it has been observed that the gas content of the bottom oil immediately after the event is practically not affected and similar to the one before the event.

By plotting the PFS as a function of gas concentration level, a sharp increase in PFS is usually observed at a given concentration [4]. This concentration is defined as the pre-failure gas concentration (PFGC) value.

Figure 1 is given as an example in the case of C2H2. The PFGC value corresponds in this case to the 99 % typical value, which means that only 1 % of C2H2 values observed in service are above the PFGC value. This is remarkably close to the annual failure rate of 0.3 % for the corresponding transformers in service (failures of the active parts). The PFGC values for the other gases are indicated in Annex B, Table B1.

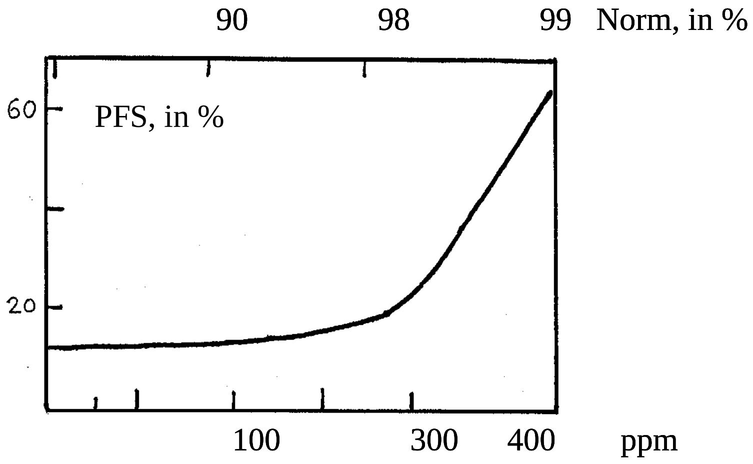

Fig. 1: Probability of having a failure-related event (PFS, in %) as a function of C_2H_2 concentration in service in ppm, and of Norm in % [a,e]

Alarm gas concentration (AGC) values are defined as values intermediate between the typical values (below which the transformer is considered as relatively safe), and the pre-failure values (above which a failure may be imminent). The choice of alarm values is dependent on the tolerance to risk of maintenance personnel, also on economic and strategic considerations (cost of increased monitoring), so it is left to users to decide.

AGC values are defined arbitrarily in this report [a] as corresponding to twice the pre-failure norm (2 % in the case of C2H2, which corresponds to the 98 % typical values). The AGC values thus calculated are indicated in Table B1. But AGC values corresponding to a different multiplication of the pre-failure norm might of course be used.

Based on the PFGC and AGC values of Table B1, equations were developed to calculate PFGC and AGC values on other networks [a] (Table B2). The typical norms in % to be used for each gas can be calculated using the actual failure rates of individual networks and the equations indicated in Table B2 . For example, if b = 0.5%, the typical norm to be used to calculate the AGC value for H2 is (100-4b) = 98%. The corresponding PFGC and AGC values in ppm can then be calculated using these typical norms. Examples of annual failure rates observed on different networks are indicated in Table B3.

The PFGC (and AGC) values thus obtained by different networks (Tables 11 and 12) are surprisingly close, suggesting that a kind of general mechanism is at work and that failure is imminent when these amounts of gases (corresponding to a critical amount of insulation destroyed and/or energy involved in the fault) are formed.

Table 11 : PFGC values calculated on different networks, in ppm

	H2	CH4	C2H4	C2H6	C2H2	CO
PFGC						
HQ [a.e]	600	400	900	750	350	3000
Labelec [b]	1318	424	993	850	408	984
LCIE- hydro [d]	550	460	700	1000	310	1500
LCIE- core [d]	900	340	830	1050	600	1200
LCIE- shell [d]	240	270	480	1800	500	1300

Table 12 : AGC values calculated on different networks, in ppm

	H2	CH4	C2H4	C2H6	C2H2	CO
AGC						
HQ [a,e]	250	120	350	400	170	1700
Labelec [b]	665	194	421	805	295	956
LCIE- hydro [d]	290	230	240	670	120	1300
LCIE- core [d]	240	150	120	800	70	1100
LCIE- shell [d]	110	200	340	1700	100	1000

Note : Pre-failure rates of gas increase (PFRGI) values and alarm rates of gas increase (ARGI) values were not calculated by TF11 because of a lack of time and data, but such a calculation has been indicated as desirable in the future, using a procedure similar to that used for calculating PFGC and AGC values.

3-STRAY GASSING OILS

Thermal "stray gassing" of insulating mineral oils, as defined by TF11 in this paper, is "the formation of gases from insulating mineral oils heated at relatively low temperatures (90-200 °C)".

Note : thermal stray gassing of oils, as defined here, should not be confused with the gassing tendency of oils under gas-phase electrical discharges (ASTM D2300B and IEC 60628) or as a result of catalytic reactions on metal surfaces or paints (IEC 60599, clause 4.3).

Such an unexpected gas formation at these low temperatures had been reported by several authors since 1998 [s,t,I,f,u]. Laboratory test results were difficult to compare, however, because they had been obtained under different test conditions. The first task of TF11 was therefore to develop standard test procedures to be used by its members.

3.1-TEST PROCEDURES OF TF11 FOR STRAY GASSING OILS

3.1.1-Procedure at 120 °C [n,g,a]

A sample of oil is degassed under vacuum, saturated with air or nitrogen by bubbling through the oil, placed in three 30-ml glass syringes and in an oven at 120 °C. After 16 hours, the first syringe is analyzed by DGA to determine the initial stray gassing of the oil [n,g]. After 164 h, the second one is analyzed to determine if a gassing plateau has been reached [a]. After 164 h, the third one is degassed, re-saturated with air or nitrogen, then put back in the oven for 16h, to determine if stray gassing is recurrent after having been heat-treated [a].

Note : these procedures have also been followed in a recent test program performed elsewhere [6].

3.1.2-Procedure at 200 °C [a]

3 glass vessels are used instead of syringes. Samples of degassed, then air- or nitrogen- saturated oil are introduced in the vessels, sealed with a torch, placed in an oven at 200 °C during the same periods of time as above, to determine how stray gassing may interfere with DGA diagnoses at temperatures closer to those of faulty hot spots in paper and oil in service.

3.2-STRAY GASSING TEST RESULTS OF TF11

Because of limited laboratory resources within TF11, tests were made under air only. Air was chosen because it had been shown previously that oxygen will produce more stray gassing, easier to measure by DGA with a good reproducibility.

Test results at 120 °C are summarized in Table 13 for 9 typical oils, and at 200 °C in Table 14 for 3 typical oils. They have been calculated in ppm/ 16h and for the main gases formed only, to facilitate the comparison of results. Complete test results in ppm are indicated in Annex C, Table C1 and C2, respectively.

In Table 13, the third stray gassing value for each oil and each gas, which corresponds to the final 16h test, has been calculated from Table C1, by subtracting the corresponding third value ("164+16") from the second one ("164"). The results in brackets correspond to cases where the oil was not degassed and re-saturated with air after the 164h heat treatment and before the final 16h test, as it should have. The reduction of oxygen content in oil in these cases, and the large background of gases from the 164h treatment, may lead to inaccurate values. “Old” and “New” Voltesso 35 refer to oils manufactured before and after 2000, respectively.

Table 13 : Typical stray gassing test results at 120 °C, in ppm/ 16h [a] of test

	H2	CH4
Test duration, h.	16-164-16	16-164-16
Nynas 10X [j]	12-7-(0)	0-0-(0)
Nynas 10XT [k]	50-16-27	1-0-2
Diala S [b]	48-19-(147)	0-1-(0)
Univolt 52 [b]	60-7-(25)	4-1-(9)
Nytro 11EN [b]	54-8-(60)	41-5-(107)
Diala G [k]	76-16-14	1-2-5
Nynas 10GBN [j]	138-27-(0)	3-14-(0)
Old Voltesso 35 [a,e]	127-9-85	161-15-88
New Voltesso 35 [a,e]	1088-240-61	172-10-219

Table 14 : Typical stray gassing test results at 200 °C, in ppm/ 16h [a] of test

Oil	H2	CH4	C2H6
Diala S [b]	49-6-(0)	89-16-(0)	91-16
Univolt 52 [b]	26-2-(6)	147-20-(0)	97-15-(0)
Nytro 11EN [b]	45-5-(0)	232-32-((0)	260-32-(0)

At 120 °C, the main gas produced in general is H2, followed by CH4, more or less markedly so depending on the oil. As can be seen in Table 13, gas formation in general is higher in the initial 16h of test.

During the following 164h, the rate of gas formation is reduced by a factor of ~ 2 to 12 depending on the oil. The gas formation plateau therefore appears to be related not only to the reduction in oxygen content of the tested oil but also, more importantly, to the type of oil. Test results performed elsewhere under both air and nitrogen similarly indicate that stray gassing is influenced more by the type of oil than by the presence or not of oxygen [6].

Gas formation in the final 16h test appears to be recurrent, at a reduced level for H2 and at an enhanced level for CH4.

Large variations in the amounts of gases formed are observed depending on the type of oil, for instance, from 12 ppm to 1088 ppm of H2 after the initial 16h. Different batches of the same brand of oil may have different rates of gas formation, by a factor of 1 to 5. The case of Voltesso 35 is interesting because it shows that its stray gassing behaviour has changed dramatically between the brands available before 2000 and those available after, possibly as a result of the use of different crude oils and refining techniques. So, new brands of oils should be checked periodically. Stainless steel and other metals have been reported to influence stray gas formation [k].

At 200 °C (Table 4), the main gases formed are CH4 and C2H6, by a factor of ~ 2 to 6 depending on the oil, then hydrogen and ethylene. The reaction mechanisms at 120 °C and 200 °C thus appear to be quite different. Gassing also reaches a plateau, but does not appear to be recurrent.

The mechanisms of stray gas formation are not known for sure. Some postulate they are related to oxidation, others to weaker chemical structures left in the oil after refining, but none of them has been demonstrated clearly so far.

3.3-CORRELATIONS WITH GASSING IN THE FIELD

In most cases, there is no correlation between test results at 120 °C and gassing observed in the field in the first year(s) of service, as indicated for example in Annex C, Table C3.

In a few cases, some correlation has been observed between field observations and test results at 120 °C and 200 °C, as indicated in Tables C4 and C5, respectively.
No correlation has been observed during factory tests.

3.4-CALCULATED CONTRIBUTION OF STRAY GASSING IN SERVICE

The impact of stray gassing in service depends on the temperature of the oil, more particularly the temperature of the hottest spot of the transformer. Typical ANSI and IEC hot spot temperatures at nominal load are 110 °C and 98 °C, respectively, but these may vary between 140 and 85 °C, or less, depending on ambient temperatures and overload conditions used in service.
The stray gassing of recent Voltesso 35 was measured at 98 °C (Table 15), and indeed found to be much lower than at 120 °C :

Table 15 : Stray gassing of recent Voltesso 35
after 16h of test, in ppm [a,e] :

Temperature	H2	CH4	C2H6
120 °C	1088	172	27
98 °C	333	4	3

The stray gassing of recent Voltesso 35 at 3 other hot spot temperatures in service was first extrapolated [a] from the values of Table 15. Then, more precise curves relating stray gassing to temperature were obtained from laboratory stray gassing tests on two other oils (Diala G and Nynas 10XT) at these 5 temperatures [k]. Values for the other oils were extrapolated by drawing curves parallel to these experimental curves from the value available for these oils at 120°C . Results are presented in Table C6 in the case of H2.

For a still more accurate evaluation, the stray gassing of all commercial oils at these 5 temperatures will eventually have to be measured in the laboratory. Extrapolated values of Table C6, however, already provide a reasonably good estimate.

Assumptions have been made[a] concerning the volume of the hottest spot in transformers, the oil volume in contact with it and the dilution/ duration factors to be used when comparing gassing in service to stray gassing tests results, and are indicated in Table C7. Using these dilution/ duration factors, the contribution of stray gassing to gas levels in transformers after 1 year in service, in ppm, has been calculated [a], and is indicated in Table 16 for 7 typical oils used, at various hottest spot temperatures.

Table 16 : Calculated contribution of stray gassing to gas levels in transformers after 1 year in service, in ppm of H2 :

Hottest-spot temperature, °C	140	120	110	98	85	Observed in service *
New Voltesso 35	3100	1700	1010	520	120	
Nytro 10GBN	620	290	190	110	55	30 [7]
Old Voltesso 35	400	200	130	80	40	**40**[a]
Technol 4000	380	180	120	70	35	8-40[c]
Diala D	340	170	110	60	30	**79**[b]
Univolt 52	170	95	60	35	20	**48**[d]
Technol 3000	60	30	20	15	10	7[c]
Nytro 10X	50	20	15	10	8	

* In black characters : TGC value after 1 year

Note 1 : strictly speaking[d], if every ml of oil in the transformer has been heated at the temperatures of Table 16 during 16h, the dilution/ duration factor cannot be > 1. It can be, however, if the heating period is > 16h, so the factor of Table C7 (1.56) has been kept for the calculations. Values in Table 16 should be viewed as rough estimates only.

Note 2 : calculated values in Table 16 take into account only the contribution of the hottest spot to stray gassing. Values may have to be multiplied by a factor of about 2 to take into account the contribution of the top oil. The contribution of bottom oil is negligible

Note 3 : in the case of the Nytro 10GBN oil, hydrogen rose to 150 ppm after 3 to 6 years in service in the several transformers monitored [7]. The reason for this delayed formation of H2 would have to be investigated further, using stray gassing tests on used oils.

There is a reasonably good agreement between calculated values of Table 16 and values actually observed in service in transformers. Results reported with the older brands of Voltesso 35, for example, correspond to transformers operating below nominal load, and may explain why stray gassing was never suspected in these equipment. Other networks appear to be operating at or slightly above nominal load.

Only when using highly stray gassing oils and/or operating under high overload conditions will the contribution of stray gassing become very significant. This may occur, for example, in hybrid transformers using Nomex paper, where operating temperatures are higher[v] .

The calculated contribution [a] of stray gassing to gas formation during heat run tests is indicated in Table 17. Note 2 of Table 16 also applies to Table 17.

In all cases the calculated contribution of stray gassing is much below the gas formation normally observed during the heat run tests. Even when using strongly stray gassing oils and/or testing above nominal load (for instance, using the Canadian heat run test at 1.5 nominal load), stray gassing will not interfere with heat run test diagnoses.

Table 17 : Calculated contribution of stray gassing to gas levels in transformers after heat run tests, in ppm of H2 :

Hottest-spot temperature, °C	140	120	110	98	85	Observed during heat run tests
New Voltesso 35	4.0	2.2	1.3	0.7	0.1	
Nytro 10GBN	0.8	0.4	0.2	0.1	-	
Old Voltesso 35	0.5	0.3	0.2	0.1	-	20
Technol 4000	0.5	0.2	0.1	-	-	50
Diala D	0.4	0.2	0.1	-	-	10-50
Univolt 52	0.2	0.1	-	-	-	10-50

3.5-IDENTIFICATION OF STRAY GASSING IN SERVICE

Depending on the type of oil used, stray gassing in service may be mistaken as corona partial discharges PDs, catalytic reactions on metal surfaces, or thermal faults T1 / T2, based on the composition of gases formed during laboratory stray gassing tests.

Stray gassing can be differentiated from corona PDs or catalytic decomposition by examining the CH4 / H2 ratio of gases formed in service (Table 18) :

Table 18 : Stray gassing vs.catalytic reactions and corona partial discharges [a]:

	Gases formed	CH4/H2
Catalytic reactions	H2	< 0.02
Corona partial discharges	H2, CH4	0.02- 0.14
Stray gassing of oil :		
-at 120 °C	H2, CH4, C2H6	0.15 - 1
-at 200 °C	C2H6, CH4, H2	> 0.4

Differentiating between thermal faults T1 / T2 and stray gassing in service is more difficult. The first thing to do in that case is to determine the expected average hottest spot temperature of the oil in the transformer (which depends on ambient temperature and load applied) , then subject the oil used in the transformer to a laboratory stray gassing test at that temperature, and calculate the expected contribution of stray gassing, using the dilution factor of Table 3. This will fix the maximum levels of gases in service due to stray gassing.

If gas levels observed in service are below these maximum levels, it will not be possible to differentiate between stray gassing and thermal faults T1 / T2.
If gas levels are above, a thermal fault is more likely than stray gassing.

4-GAS FORMATION FROM PAPER

Faults in paper in service are generally considered as much more serious than faults in oil. However, determining whether paper is involved or not is not always an easy task. IEC 60599 recommends to use the CO2 / CO ratio for that purpose. A ratio < 3 is a good indication that paper is involved. However, there are often large backgrounds of CO2 and CO in oil in service, which make the ratio unreliable, especially if the fault in paper is a new one. For that reason, it is recommended to subtract the previous values of CO2 and CO from the present ones before calculating the ratio. This , however, will result in a larger error on the incremented ratio, which may again become not very reliable.

Surprisingly, few experimental data are available concerning gas formation from paper, and these date back mostly to the 1970's. TF11 therefore tried to get new, more precise data from tests on small transformer models and laboratory vessels. These are indicated in Table 19, expressed in units allowing comparisons with actual gas formation rates in transformers in service, and the calculation of the amounts of paper involved in a fault. Attempts to get laboratory data at temperatures higher than 160 °C were unsuccessful because of the glass vessels and/ or paper / oil ratios used.

Table 19 : Rates of gas formation from paper,
in ppm/ year / kg of paper / 50,000 l of oil

Paper Temperature	C2H2	H2	CH4	C2H4	C2H6	CO	CO2	CO2/ CO	Oil used	Ref.
125 °C	0	0.4	0.3	-	-	4	220	50	Nynas 10CX	[e]
135 °C	0	0.3	0.4	-	-	5	230	42	Nynas 10CX	[e]
160 °C	0	40	12	3	3	122	1830	15	Nynas 11EN	[c,b]
250/ 300 °C *	0	123	200	85	38	23400	78000	3.5	Technol 4000	[c]

Notes : values corrected for stray gassing interference in case of Nynas 11EN.
* : average winding temperature / estimated hot spot temperature in a small transformer.

Using the assumptions of Table C7, it has been calculated [a] that a hottest spot of 125 °C in the windings will produce 10 ppm of CH4, 130 ppm of CO and 6600 ppm of CO2 in oil after 1 year of operation.

5-GAS FORMATION FROM PARTIAL DISCHARGES

PD energies of 100 mJ , corresponding for example to several discharges of 100,000 pC to 1 million pC , are necessary to generate 5 to 7 μl of gas [8-9]. In a transformer with 50,000 l of oil, this corresponds to 1 ppm of gas formed in service per kJ contained in the PDs.

This explains [a] why no gas formation in general is observed by DGA during high sensitivity electric or acoustic PD tests, able to detect PDs in transformers in the low-to-medium pC range. These PDs simply do not contain enough energy to form detectable gases and degrade the paper and oil insulation. As long as they do not develop into more severe types of discharges or arcing, such PDs therefore are harmless, maintenance personnel should not worry about their possible effects on the insulation, and DGA analyses during the tests are not needed.

6-GASES TRAPPED IN PAPER INSULATION

Cases [r,c,f] related to the release of gases from the paper insulation of transformers have been examined. These transformers had been gassing in service, decommissioned, stored for long periods of time without oil, then put back in service with degassed oil. A continuous increase of gas content was observed in the tank oil of these transformers, sometimes quite a long time (8 years) after re-energization.

The amount of oil contained in oil-impregnated paper is about 7 % of the total volume of oil in a transformer. If the transformer has been gassing, large quantities of gases will be trapped in the oil impregnating the paper insulation, which are more than enough to explain the subsequent release of gases into the main tank of re-commissioned equipment, without having to postulate any absorption or “dissolution” of gases in the cellulose itself.

Once trapped in the paper-impregnated oil, gases are very difficult to remove. Based on the observed diffusion rates from paper, it would take 10 to 20 years to extract the hydrocarbons at ambient temperature. It is therefore not surprising that even after a 10-year storage at ambient temperature, there was still a lot of gas trapped in the oil-impregnated paper.

Even applying a vacuum cannot totally extract the trapped gases. The only way to do that is by increasing the temperature to 60 ºC during a 1 to 6 month period for H2 and hydrocarbons, and to 70-90 ºC during 3 to 6 months for CO, CO2 (see Annex D, Figure D1).

To ensure the complete release of gases trapped in paper, it would be necessary, after repair or storage of a previously gassing transformer, and before putting it back in service, to heat-treat the transformer with degassed oil at 60 to 90 ºC for 1 to 6 months, then re-degas the oil by circulation. An alternative procedure would be to subject the transformer to vapour-phase drying to remove the contaminated oil from paper.

Both of the above procedures are costly and time consuming, and it is generally preferred in the industry to simply degas the transformer and put it back in service.

Gas formation will occur with a pattern similar to the one observed before degassing, but at a reduced gas concentration level (typically, 2 to 5 times lower after 2 years in service). By performing regular oil samplings for DGA every 1 to 2 months during a 6 to 12 months period, it is possible to identify the gas pattern due to trapped gases, and to attribute any deviation from this gas pattern to a new fault occurring in the transformer, if the residual level of trapped gasses is not too high.

7-FAULTS DETECTABLE BY DGA

A list of faults detectable by DGA [5] has been submitted to CIGRE WG 12.18 and included as a complement to its final report [10]. These are the faults specified in IEC 60599 (Partial Discharges of the gas-phase, corona-type PD; Discharges of low energy D1 (sparking, tracking or small arcing); Discharges of high energy D2 (arcing with power follow-through) ; Thermal faults T1, of temperatures < 300 °C; Thermal faults T2, of temperatures between 300 and 700 °C; Thermal faults T3, of temperatures > 700 °C.

8-CONCLUSIONS AND RECOMMENDATIONS

8.1-Dissolved gas concentrations in service

The typical values of gas concentrations and typical rates of gas increase observed in service on different networks worldwide have been surveyed and are indicated in this report. Individual networks, however, are recommended to calculate their own typical values whenever this is possible. The influence of various parameters on typical values (age, oil volume and type of the equipment) has been precised.
The gas concentrations observed just before failure on different networks appear to be surprisingly similar.

8.2-Thermal stray gassing of oil

This refers to the unexpected formation of gases in oil at relatively low temperatures, such as 100 °C. It is shown in this report that stray gassing in general will not interfere with DGA diagnoses in service, as initially assumed, unless a very strongly stray gassing oil is used or operation is largely above nominal load. Heat run tests in general will not be affected by the stray gassing of oil.

Users are recommended to verify the stray gassing tendency of their oils at the hottest spot temperature of their transformer, which depends on load conditions and ambient temperatures. Tests are described for that purpose, and methods to calculate the contribution of stray gassing to gas formation in service. Criteria are also indicated to distinguish between stray gassing and other types of gas formation in service (catalytic reactions on metals, partial discharges, low-temperature thermal faults).

8.3-Gas formation from paper

Gas formation rates from paper at various temperatures are provided, allowing to calculate the amount of paper involved in a fault.

8.4-Partial discharges

DGA is particularly useful to determine when partial discharges start becoming harmful to the insulation, and detectable by visual inspection.

8.5-Gases trapped in paper insulation

These gases are very difficult to remove completely. Methods given to either remove them or use the gas patterns they are releasing in oil in service to distinguish them from newly occurring faults.

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ANNEX A

Table A1 : 90% TRGI values vs. oil volume in power transformers without an OLTC, in ppm/ year

Company	Number of analyses	Oil volume, Kliters	H2	CH4	C2H4	C2H6	C2H2	CO	CO2
Hydro -	3011	0-5	6	2	3	1	0.4	70	430
Quebec [a,e]	2497	5-20	113	28	48	20	2	540	6720
	6219	20-50	52	14	33	9	1	590	4500
	7643	> 50	75	49	146	38	2	1060	6870
LCIE [d]	2373	35	35-50	51-121	34-66	51-92	0-4	300-310	2260-10,070
Labelec [b]	128	0-5	25	20	7	41	0	100	600
	118	5-20	26	45	49	25	1	225	2100
	36	20-50	89	42	8	30	0	294	7000
	7	> 50	8	15	14	2	0	351	7000
Ranges		0-5	6-25	2-20	3-7	1-41	0-0.4	70-100	430-600
of values		5-20	26-113	28-45	34-49	20-25	0-2	225-540	2100-6720
		20-50	35-89	14-121	8-66	9-92	0-4	294-590	2260-10,070
		> 50	75	49	146	38	2	1060	6870

Note : values corresponding to less than 80 analyses have not been considered in the compilation of ranges, as they may not be statistically significant.

Table A2 : 90% TRGI values vs. age in power transformers without an OLTC, in ppm/ year

Company	Number of analyses	Age, years	H2	CH4	C2H4	C2H6	C2H2	CO	CO2
Hydro Quebec [a,e]	1589	0-2	230	73	307	68	0	2229	9710
	2827	2-5	106	96	189	73	2	973	5720
	5451	5-15	29	15	42	11	1	545	3990
	5717	15-30	25	8	23	6	1	334	2921
	3932	> 30	86	21	42	12	1	422	5803
LCIE	25	0-2	90	65	84	167	0	225	7001
Hydro [d]	53	0-5	35	62	27	196	0	225	6223
	106	5-10	126	131	103	95	2.9	419	3478
	332	10-20	36	87	47	63	1.5	297	2188
	630	20-40	30	32	13	33	0.7	309	1672
	300	> 40	135	40	35	48	2.4	260	2373
	1446	All	47	51	34	53	1.3	309	2236
LCIE Transm [d].	184	0-5	83	124	66	395	7.3	331	3685
	235	5-10	17	21	11	111	1.7	130	977
	367	10-20	29	25	13	70	2.0	118	775
	196	20-40	54	34	13	55	1.1	257	1695
	10	> 40	95	315	450	145	21.3	243	590
	1050	All	34	44	23	150	3.0	185	1219
Labelec [b]	25	0-5	24	25	5	112	0	56	700
	45	5-10	42	20	4	74	0	197	2100
	87	10-20	30	21	27	8	1	217	2500
	70	20-30	7	16	17	5	0	237	1000
	93	> 30	51	28	13	22	0	233	2500
Ranges of values		0-5	83-230	62-124	66-307	68-395	0-7	225-2229	3685-9710
		5-10	29-126	15-131	11-103	11-111	1-3	130-545	977-3990
		10-30	7-54	8-87	13-47	6-70	1-2	118-334	775-2921
		> 30	51-135	21-315	13-450	12-145	1-21	243-422	590-5803

Note : values corresponding to less than 80 analyses have not been considered in the compilation of ranges, as they may not be statistically significant.

Table A3 : 90% TRGI values vs. age in power transformers with an OLTC, in ppm/ year

Company	Number of analyses	Age, years	H2	CH4	C2H4	C2H6	C2H2	CO	CO2
LCIE Transm.[d]	34	0-5	330	123	95	255	175	-	1617
	59	5-10	115	64	92	134	56	274	2612
	243	10-20	75	53	32	78	46	370	1687
	541	20-40	208	76	22	36	20	346	1838
	14	> 40	19	17	7	38	1	58	604
	900	All	132	67	32	57	37	328	1797
Hydro-Quebec[a,e]	443	0-2					76		
	991	2-5					168		
	3978	5-15					48		
	5152	15-30					27		
	2099	> 30					14		
	12,706	All	35	10	33	5	36	261	1711
Labelec[b]	89	0-5	57	33	12	141	17	142	1700
	122	5-10	35	23	19	49	11	183	1900
	320	10-20	30	21	27	8	1	217	2500
	293	20-30	21	23	27	20	30	188	2200
	205	> 30	88	18	25	13	30	162	2000
	323	All	53	44	52	53	21	279	3000
Ranges of values		0-5					17-168		
		5-10					11-48		
		10-20					1-46		
		20-30					20-30		
		> 30					14-30		

Note : values corresponding to less than 80 analyses have not been considered in the Compilation of ranges, as they may not be statistically significant.

Note : the number of analyses without consideration of age (“All”) may not always be the exact sum of the numbers of analyses for each age category, if different DGA data banks have been used.

Table A4 : proportion of air-breathing and sealed transformers in different countries

Country	Air breathing (%)	Sealed (%) *
Spain	100	0
UK	99	1
Portugal	99	1
Canada	97	3
Denmark	97	3
Germany	95	5
Norway	90	10
Sweden	85	15
France	80	20
Israel	10	90
Italy	10	90
Iceland	10	90
USA	0	100
Ukraine	0	100

* i.e., equipped with a membrane in the conservator, the main tank, or with a nitrogen blanket.

ANNEX B

Table B1 : PFGC and AGC values calculated from PFS curves [a,e]

	H2	CH4	C2H4	C2H6	C2H2	CO
PFGC, ppm	600	400	900	750	350	3000
Norm, %	98	97	97	99	99	99.5
AGC, ppm	250	120	350	400	170	1700
Norm, %	96	94	94	98	98	99

Table B2 : equations to determine the % Norms to be used for the calculations of PFGC and AGC values in power transformers without a communicating OLTC [a]

	H2	CH4	C2H4	C2H6	C2H2	CO
PFGC Norm, %	100-7a 100-2b	100-10a 100-3b	100-10a 100-3b	100-3a 100-1b	100-3a 100-1b	100-2a 100-½b
AGC Norm, %	100-14a 100-4b	100-20a 100-6b	100-10a 100-6b	100-6a 100-2b	100-6a 100-2b	100-4a 100-1b

where :
- a%, for failures involving work on the active parts of the transformers in the repair shop
- b%, when minor failures on the connections to accessories (OLTC, bushings) are added to the above failures on the active parts.

Table B3 : examples of annual failure rates on different networks

Annual failure rate in % :	a	b
Hydro Quebec [a]	0.3	1
Labelec [b]	0.04	0.4
LCIE [d]	0.5	1

ANNEX C

Table C1 : Stray gassing test results at 120 °C, in ppm

Ref.	Oil brand	Type	Duration, h	H2	CH4	C2H4	C2H6	CO	CO2	O2
[c]	Technol US 4000		16	3	1	-	-	3	43	
[j]	10X	I	16 164 164 + 16	12 73 40	- - -	- - -	- - -	7 69 43	394 521 454	19514 16701 21595
[l]	10X	I	16 164 164 + 16	15 55 45	- - -	- - -	- - -	11 90 99	64 185 294	31333 22842 24379
[j]	Nitro 10X		16 128 192	37 168 191				50 171 194	559 814 794	
[l]	10X	I	16	-	-	-	-	31	817	42940
[d]	10X	I	16	23	-	-	-	5	75	
[d]	Univolt 54		16	11	4	-	-	23	130	
[d]	Total Isov.		16	35	5	-	5	9	120	
[b]	Univolt 52	P	16 164 164 + 16	60 73 98	4 5 14	- - 4	- - 10	96 100 193	470 400 600	14000 11000 10000
[l]	Univolt 52 (Ireq)	P	16	55	3	-	-	87	367	23638
[j]	Univolt 52	P	16 164	116 142	75 23	- 4	100 12	188 222	430 1205	1145 571
[d]	Univolt 52	P	16	4	10	-	13	13	67	
[k]	10XT		16 164 164*+16	50 161 27	1 4 2	- 1 -	- - -	18 15 41	93 232 145	18870 8530 20740
[k]	Diala G		16 164 164*+16	76 167 14	1 20 5	- 2 -	- 7 -	20 141 5	79 235 54	14640 1290 12530
[a,e]	Voltesso 35 (before 2000)	NI	16 164 164 + 16	127 92 85	161 158 88	11 11 7	32 78 9	764 552 499	1181 1841 1358	
[b]	Nitro11EN	N	16 164 164 + 16	54 82 142	41 54 161	- - 3	33 38 114	79 80 219	340 230 470	10000 11000 9000

Table C1 : Stray gassing test results at 120 °C, in ppm (cont.)

Ref.	Oil brand	Type	Duration, h	H2	CH4	C2H4	C2H6	CO	CO2	O2
j	Y3000		16	8				11	483	27250
			192	269				192	667	
j	Y3000, 1 year old		16	77	48	17	12	376	2688	574
c	Technol US 2002		16	143	14	-	6	25	69	
j	Diala AX		16	48	-	-	-	99	1190	21637
			164	335	23	6	3	414	1430	642
			164 + 16	317	22	6	3	393	1632	560
l	Diala AX		16	-	3	-	-	58	166	52949
			164	92	4	3	-	233	447	11310
			164 + 16	127	7	5	-	327	439	8691
d	Diala AX		16	344	4	2	-	298	469	
d	Addinol		16	58	23	-	30	65	130	
b	Diala S		16	48	-	-	-	77	36	19000
			164	187	9	4	6	318	560	9000
			164 + 16	334	6	4	-	512	700	8000
d	10BN Ireq		16	98	9	5	7	17	120	
l	10BN		16	116	-	-	-	149	960	40057
j	10BN Ireq		16	239	-	-	-	40	705	19477
			164	472	19	3	16	136	960	756
c	10BN		16	8	10	-	6	11	24	
d	10GBN	UI	16	72	4	-	3	5	63	
l	10GBN	UI	16	22	-	-	-	20	545	40751
j	10GBN	UI	16	138	3	-	-	29	394	459
			164	269	145	-	104	151	481	533
			164 + 16	240	114	-	86	106	454	529
l	10GBN	UI	16	93	-	-	-	13	56	25330
			164	183	147	3	130	138	267	2908
			164 + 16	186	138	-	116	123	237	1711
a,e	Voltesso 35 (after 2000)	NI	16	1088	172	11	27	500	1880	
			164	2399	105	8	41	402	2354	
			164 + 16	61	219	8	65	367	1692	

Note : concentrations below 2 ppm are indicated as zero (-) in the tables

Table C2 : Stray gassing test results at 200 °C, in ppm

Ref.	Oil brand	Temp., °C	Duration h	H2	CH4	C2H4	C2H6	CO	CO2	O2
[d]	10GBN	70-180	10x24	134	84	10	25	672	2040	1709
[b]	11EN	70-180	10x24	167	60	24	16	1048	4000	
[b]	11EN	200	24 164 164 +16	68 56 41	348 331 234	40 5 8	390 325 232	601 469 391	1500 1100 1000	5000 5000 9000
[b]	Diala S	200	24 164 164 +16	74 63 43	134 167 125	38 - -	136 166 1137	653 638 475	3500 2300 2000	5000 3000 10000
[b]	Univolt 52	200	24 164 164 +16	39 25 31	221 201 192	37 40 31	145 158 130	619 513 577	2300 2500 2300	3000 6000 8000

Table C3 : Cases where no correlation can be made between stray gassing test results at 120 °C and gassing observed in the first year(s) in service, in ppm

Oil		H2	CH4	C2H6
Univolt 52 [b]	Tests	60-73-98	4-5-14	0-0-10
LCIE [d]	Service	48	137	241
Old Voltesso 35 [a,e]	Tests	127-92-85	161-158-88	32-78-9
HQ [a]	Service	40	10	2

Table C4 : Cases where some correlation can be made between stray gassing test results at 120 °C and gassing observed in the first year(s) in service, in ppm

Oil		H2	CH4	C2H6
10GBN [k]	Tests	184-198-197	50-112-112	45-86-86
NG [v]	Service	30-150	20	50
Diala D [k]	Tests	108-61-60	88-100-100	82-106-107
Labelec [b]	Service	79	26	54

Table C5 : Cases where some correlation can be made between stray gassing test results at 200 °C and gassing observed in the first year(s) in service, in ppm

Oil		H2	CH4	C2H6
Nytro 11EN [b]	Tests	68-56-41	348-331-234	390-325-232
EdF [a]	Service	10	288	528
Univolt 52	Tests	39-25-31	221-201-192	145-158-130
LCIE	Service	48	137	241

Table C6: Stray gassing vs. temperatures, in ppm of H2, after 16h of test

Temperature, °C	140	120	110	98	85
New Voltesso 35[a,e]	2000	**1088**	650	**333**	75
Nytro 10GBN	400	**184**	120	70	35
Old Voltesso 35	260	**127**	85	50	25
Technol 4000	245	**117**	80	45	23
Diala D	220	**108**	70	40	20
Diala G[k]	**173**	**76**	**54**	**24**	**14**
Univolt 52	110	**60**	40	22	12
Nynas 10XT[k]	**88**	**50**	**32**	**21**	**10**
Technol 3000	40	**18**	13	10	8
Nynas 10X	30	**12**	9	7	5

Note : in dark characters : measured values
in normal characters : calculated values, extrapolated from measured values

Table C7 : Assumptions concerning the dilution / time factors to be used when comparing gassing in service to stray gassing tests results [a]

Volume of oil	60,000 litres
Volume of windings	6,000 litres
Volume of magnetic parts	6,000 litres
Volume of hottest spot in windings	5 % of windings volume = 300 litres of windings = 150 litres of oil
Volume of hottest spot in magnetic parts	5 % of magnetic parts = 300 litres = 15 litres of oil
Volume dilution factor	165 / 60,000 = 0.003
Duration of stray gassing test	16h = 0.7 day
Duration factor in service (1 year)	365 / 0.7 = 521
Duration factor during heat run tests (12 h)	12 / 16 = 0.75
Global dilution factor in service	521 x 0.003 = 1.56
Global dilution factor during heat run tests	0.75 x 0.003 = 0.002

ANNEX D

Figure D1 : Release of gases from paper insulation with temperature [r,a]

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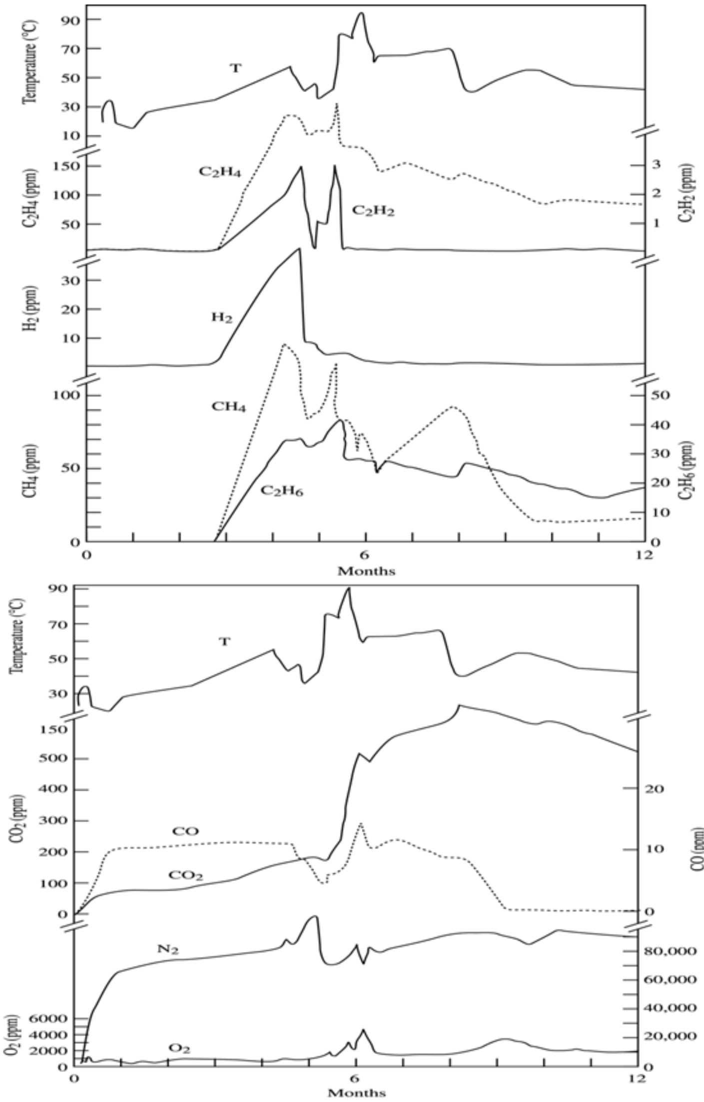

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