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TRANSFORMER LIFE MANAGEMENT
GERMAN EXPERIENCE with CONDITION ASSESSMENT

I. Höhlein, A. J. Kachler*,
Siemens AG, PTD T, Nuremberg, DE

S. Tenbohlen
Alstom Schorch Transformatoren GmbH,
Mönchengladbach, DE

M. Stach
E-ON Engineering Gelsenkirchen, DE

T. Leibfried
Techn. University Karlsruhe, DE

1. SUMMARY

This paper is a cooperate effort of German manufacturers, utilities and technical universities on the subject of state of the art of Transformer Diagnostics and Life-Management.

After a brief introduction to generally applicable diagnostics to verify ageing physically due to

- Dielectric stresses
- Thermal stresses
- Mechanical impact and
- Chemical changes

the paper extends on the diagnostic procedures to identify functionally and component related ageing defects.

The main sections provide the German experience and numerous examples of successful diagnostics of physically different stresses.

Finally, some Guidelines of how to proceed in complex defective conditions – where we need at least two different approaches.

The paper concludes with most effective diagnostic procedures and recommends to continue effective research of Moisture Dynamics and Furane Analysis.

* Main author, Siemens PTD T QM

2. INDEX

3. STATE OF ART OF DIAGNOSTIC PROCEDURES

The transformer is a very complex structure with basically 5 different main materials: copper – core steel – tank steel / and – main/minor insulation and insulating oil.

All metallic materials are ageing very slowly, therefore all functional life considerations / ageing impacts are related to insulation material and oil.

Utilities and Manufacturers and technical University have developed a wide range of diagnostic procedures to detect loss of life or functionally (component wise) faulty or defective conditions [1].

3.1 Objectives of Condition Assessment of Power Transformers

Transformer Life Management is primarily directed to transformer life extension and to cutting of operational costs and risks. Most diagnostic systems including of On-Line Monitoring serve to detect changes in the insulation system in form of an early warning system, due to- thermal / dielectric / chemical or mechanical impact, i. e. to detect

- Hotspots
- Degradation of the insulation
- Excess moisture in insulation
- Localized faults / defects
- Partial discharges
- Partial rupture / mechanical defects / briddleness
- Chemical or thermal ageing.

Normally, none of these defects can be detected by a singular diagnostic procedure. Therefore, we need to apply a multitude of different methods.

Furthermore to enable trend analysis and condition assessment we need quite frequently a sequence of samples and measurements to identify the velocity of change, the rate of progressiveness, the quantity of indicated signature etc.

In order to cover the multitude of perspectives we must identify the **appropriate measurands** and **procedures**, which are:

For thermal degradation (oil and solid insulation)

- Hotspot measurement
- On-Line Monitoring of oil/copper temperatures (hotspot) cooling plant and ambient temperatures
- DGA-Analysis (Hotspots with / without insulation degradation)
- Oil-Analysis (Oil numbers, purity, breakdown voltage (VBD))
- Furane Components Analysis (HPLC-Analysis)
- Dielectric response measurement (PDC, FDS) (Amount of absorbed moisture in insulation and oil)
- DP-(Depolymerisation index)
- Karl Fischer test
- Power factor of oil and insulation
- Oil Ageing / oxidation tests (acc. to Baader / IEC)

For dielectric degradation (oil and solid insulation)

- Partial discharge measurements (Ui, Ue, Q, trend)
- Ultrasonic localization of PDs
- Analysis of the Oil Quality / Purity / Filtering
- H_2O content in oil, breakdown voltage VBD
- Moisture in solid insulation / PDC-Analysis
- DGA (indication of PD, Arcing, Abnormal cellulosic degradation)
- Oil numbers (BDV, dissipation factor, interfacial tension (IFT), neutralization number, etc.)
- On-Line Monitoring of PDs
- On-Line Monitoring of over-voltage transient conditions.

For chemical degradation (oil and solid insulation)

- Oil-Analysis (loss factor, breakdown voltage, appearance (sludge, colour) acidity, IFT, etc.)
- DGA (Detection of transformer failures)
- Furane Components Analysis
- Oil Ageing / oxidation performance (Baader / IEC, etc.)
- DP-analysis of solid insulation
- PDC-Analysis

For mechanical degradation

- Impedance measurements with precision instrumentation for U/i-measurement
- Low Voltage Injection (LVI)
  DC-Resistance
- FRA (Frequency Response Analysis)
- Transfer function analysis
- Visual inspections
- Repeat of HV-Tests at (80 % UT).

Limitations:

All diagnostic procedures need significant diagnostic experience in order to derive the appropriate decision. Whilst the identification of dielectric / thermal / chemical deficits are possible today - the geometric localization is normally not possible. For this, ultrasonic identification of partial discharges is needed, but this requires almost laboratory test condition at site.

As can be seen from this preposition mechanical impacts / deficits can only be detected by means of Fingerprints and consecutive measurement. Mechanical defects do not show up in the DGA/Oil Analysis. Also the Dielectric Response Measurement (FDS or PDS) is not applicable.

3.2 Component Related Procedures

Power Transformer Diagnostics must also identify ageing of different physical functions and components. This is also described in [1, 2 and 3]. [3] is the **latest Draft of the CIGRE WG 12.18, where the physical functions are identified as "transformer subsystems".**

The key elements are:

- Dielectric (major, minor insulation, leads insulation, static shields)
- The electromagnetic circuits (core, windings, clamping, shields, grounding circuit)
- The current carrying circuits (leads, winding conductors)
- Insulation structure
- Clamping structure
- Magnetic shields
- Grounding circuit
- Bushings
- Tap changers OLTC
- Cooling equipment
- Protection and Monitoring equipment

Each of these subsystems has their own defect and failure evolution and expose also different symptoms of degradation.

From the large number of subsystems we select:

3.2.1 Dielectric (major / minor insulation, leads, windings)
3.2.2 Magnetic circuit (core, windings, clamping)
3.2.3 Tap changers (OLTC)
3.2.4 Mechanical Degradation

and present some practical samples examples in chapter 4 below.

Coding / abbreviations of the different diagnostic procedures throughout the paper are:

DGA:	A
Oil Analysis / Oil Ageing	B
Dielectric response Meas.	C[4,5,6]
PD-Measurement / Localization	D
FURAN DERIVATE Analysis/DP value	E[7]
DC-Resistance	F [8]
Surface Resistance	G [8]
Core Ins. Resistance Meas.	H
Hot spot temperature	I
LV No-Load Measurement	J
LV Impedance Measurements	K
VIBRATION Sound Meas.	L
ON-LINE Monitoring	M[13]

3.2.1 Dielectric Defect / Thermal and dielectric Ageing Defect / Failure Identification

The main deficiency / defect symptoms and Diagnosis Procedures are:

a) Partial discharges of low or high energy (A, C, D, M)
b) Abnormal aged oil (A, B, E)
c) Abnormal cellulose ageing (A, B, C, E)
d) Loose connections / sparking (A, B)
e) Oil contamination (B, C)
f) Excessive water content (B, C, M)
g) Destructive PD (tracking / creeping) (A, D, M)

3.2.2 Magnetic Circuit (core, grounding, winding, clamping)

The main deficiency / defect symptoms and Diagnosis Procedures are:

a) Abnormal Circulating Currents in parts of the core (core burn) with parts being shorted, hotspots, local over heating (A, B, M)
b) Loosening of the core clamping – excessive vibration (L)
c) Double grounding / short circuit in the ground circuit, circulating currents – overheating, localized hotspots, sparcing (A, B, H, I)
d) Short between conductors of parallel strands (excessive losses), stray flux effect, hotspots, circulating current (A, B, D)
e) Poor solder joints within the winding and at lead connections, etc. (A, B, F)

3.2.3 Tap changers

Tap changers defect symptoms and Diagnosis Procedures are:

a) Local hotspots due to contact overheating (A, B, F, G) [8]
b) Excessive / or significant increase in required torque (M)
c) PD-surface tracking (A, B, D)
d) Sparking / breakdown across support structures, produces tapping short circuit with complete destruction of the winding and the OLTC (A, B, D)
e) PD between lead structures due to contamination (A, B, D)

3.2.4 Mechanical degradation

The most important defect symptoms and Diagnosis Procedures are:

a) Loosening of winding clamping (K, L)
b) Loosening of core clamping (L)
c) Lead support failures (K, L)
d) Winding deformation (buckling, tilting, twisting) (K)
e) Loss of DP of the insulation system / winding conductor insulation briddleness (C, E).

4. GERMAN EXPERIENCE FOR CONDITION ASSESSMENT IN POWER TRANSFORMERS

Here we present altogether 13 cases of diagnostic results from Generator Step up Units (GSU) and System Transformers (ST)

No. 1: 300 MVA-, 245 kV - ST
Defective: Insulation System
LFA Drying /PDC-Analysis / K. Fischer

No. 2: 600 MVA-, 420 kV - ST,
Defective: cooling unit
Therm. Resistance Increase

No. 3: 74 MVA-, 123 kV - Rectifier Transformer (closed system)
Defective: Core
DGA Analysis

No. 4: 438 MVA-, 420 kV - ST
Defective: Insulation System
Moisture, DP, Oil and Furane Analysis

No. 5: 340 MVA-, 245 kV - ST
Defective: Winding Contamination
DGA, PD

No. 6: 40 MVA-, 123 kV - ST
Defective: cooling system
DGA, Furanes

No. 7: 234 MVA-, 345 kV - ST
Defective: winding
DGA, DC Resistance

No. 8: 60 MVA-, 123 kV- Reactor
Defective: cooling system
DGA / Furane, DP, Oil Analysis

No. 9: 60 MVA-, 123 kV - ST
Defective: OLTC
DGA/Hot spot
Contact / Surface Resistance

No. 10: 175 MVA-, 525 kV - GSU
Defective: winding
In Winding Short Circuit between 1 double disc, due to contamination
Example of mechanical defect recognition

No. 11: 380 MVA-, 245 kV - GSU
Defective: insulation system
DGA, DP
Connector overheating

These 11 cases are given in detail in chapter 4. In chapter 5 we give additionally some peculiar cases as No 12 and No 13.

No 12: 400 kVA, 12 kV
No defective components
Effect of oil on Catalytical Zn-Surfaces

No 13: 300 MVA-, 420 kV - ST
No defective components
DGA, H_2 steady increase, On-Line Monitoring

CASE HISTORIES

Case Nr. 1: 300 MVA-, 245 kV - ST, manufactured 1978

Defective Insulation System
Fault Symptom: Excessive water content, aged insulation system
Detected by: PDC, Karl Fischer in Oil, DP (B, C, E)

History:

1998 there was a warning with a gas in the Buchholz relay. The DGA Analysis did not give any indication of transformer failure, only the fault gases from thermal-oxidative cellulosic degradation were slight elevated. The oil analysis, however, showed an excessive water content in oil and the presence of sludge. The colour, neutralization number and the loss factor were also elevated. The sludge led to a tarnish on the tap changer contacts and elevated surface resistance. The contacts have been cleaned through switching. 2000 the oil was changed against an inhibited one. The oil numbers – colour, acidity, loss factor became better, but the increased water content was further present, because the most water is stored in the solid insulation.

2002 a LFH drying of the transformer has been performed (Approximately 100 l water were removed).

A paper sample was taken from phase V. It showed a depolymerisation (DP) value of 350 – indicating an advanced cellulosic destruction, surely influenced by moisture. The water extracts from the LFH drying were very acidic – they contained in high amounts acetic and formic acid and various aldehydes, amongst which furfural was in the highest concentration.

Diagnosis: Excessive moisture in the insulation system, dielectric detioration of the insulation system
Action taken: LFH Drying on site
The ST is successfully operating since 2002.

Case Nr. 2: ST, 600 MVA-, 420kV - ST

Defective cooling unit
Fault Symptom: Increase of thermal resistance
Detected by: Online Monitoring (M)

History:

On-line monitoring of the cooling unit of a 420kV / 600MVA grid-coupling transformer by calculation of the nominal thermal resistance Rth as described in [11,12] showed a strong increase after switching on of two additional fans which was signalled by the control system. This increase triggered a warning message by the monitoring system. A local check in the substation revealed that due to a failure of energy supply only half of the cooling unit (3 fans) was in operation and therefore only three fans were running. This status was not in accordance with the information of the control system and led to the strong increase of nominal thermal resistance. With the present load and half of the cooling power the transformer could be kept in service. But it would not be possible to operate the transformer with nominal load due to the missing cooling power. This scenario shows the importance of detecting also minor failures to avoid the risk of not delivering energy.

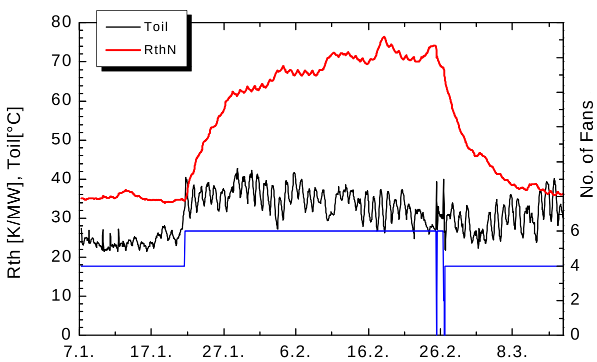


Fig. 1: Abnormal condition of cooling unit detected by increase of thermal resistance Rth

Case Nr. 3: 74 MVA-, 123 kV – Rectifier Transformer, manufactured in 1989, sealed type (rubber bag)

Defective core
Fault Symptom: Fault gases from thermal oil degradation without involvement of solid insulation
Detected by: DGA (A)

History:

Shortly after commisioning (1990) a progressive increase of the fault gases from thermal oil degradation without involvement of the solid insulation has been observed (Table 1, MSS Code 00122 – Fault code according the DGA evaluation schema of Mueller-Schliesinger-Soldner, indicating local overheating 300 – 1000°C).

Type of Fault Gas	Dissolved gas in ppm (v/v)
Hydrogen	498
Methane	1600
Ethane	495
Ethylene	1620
Acetylene	4
Propane	129
Propylene	1170
Carbon monoxide	300
Carbon dioxide	1440
Oxygen	2310
Nitrogen	13300

Table 1 : Last DGA results before disassembly.

In a transformer with a rubber bag the fault gases are accumulating in oil, reaching much higher concentrations as in a open breather, where they can escape. The total gas content in a sealed type transformer is lower than in an open breather, because there is no access of air (oxygen und nitrogen). Therefore the oxidizing effect of oxygen is negligible. Nevertheless it should be kept in mind that free gas (bubble formation) is possible, depending on the fault gas solubility in oil and the partial gas pressure.

The rectifier was returned to the factory for repair. A core burn (See Fig. 2) as a consequence of a transport damage was the source of the abnormal circulating currents in the core. The core has been repaired.

Diagnosis: Core burn as a consequence of high circulating currents.

Action taken: Repair of the core and introduction of magnetic shielding.

The unit is ever since operating troublefree.

Fig 2: A severe core burn as a consequence of high circulating currents

Case Nr. 4: 438 MVA-, 420 kV - ST, manufactured 1969

Defective Insulation System
Fault Symptom: Oil analysis, indicating aged and humid insulating system
Detected by: Oil Analysis, Furanes (B, E).

History:

This transformer has been in service for a long time before it was used as stand-by transformer for a period of about 8 years. The routine oil-checks after recommencement (Table 2) indicated an accelerated ageing of the insulating system.

	1994	1995	1999
degree of purity, impurity	pure	pure	pure
colour	2,5	3,0	3,0
refractive index	1,4722	1,4725	1,4732
neutralizing index (mg KOH/g oil)	0,10	0,10	0,12
dielectric loss factor	0,035	0,069	0,083
Water according to Karl Fischer (mg/kg oil)	15	21	36
Breakdown voltage	> 60	> 60	> 60

Table 2: Consecutive oil analysis

In consequence of this result the oil-checks have been intensified. They clearly indicated (Table 3) highly aged insulation. In addition high level of moisture and extremely low breakdown voltage of the oil were detected.

Date	Temp. [ºC]	Water according to K. - F [mg/kg]	Breakdown voltage [kV/2,5mm]
14.10.99	58	36	36
27.10.99	61	45	28
08.11.99	55	33	31
11.11.99	56	38	38
18.11.99	48	57	34
22.11.99	63	45	20

Table 3: Water content and breakdown voltage of oil

The additional furfurol-analysis (Table 4) indicated also a severe ageing of the solid insulation.

substance	concentration [mg/kg]
5-HMF (5 Hydroxymethyl-2-Furfurol)	< 0,05
2-FOL (2- Furfurylalkohol)	< 0,05
2 FAL (2-Furfural)	6,00
2-ACF (2-Acetylfuran)	<0,05
2-MEF (5-Methyl-2-Furfurol)	< 0,05

Table 4: Furane Analysis

The transformer obviously had reached the end of its life time. It was taken out of service. The determination of water in insulation according to Karl Fischer resulted in values up to 5%.

DP-determination of insulation resulted in an average value of 181 which was an indication of a complete cellulosic degradation.

Diagnosis: Highly aged insulation and oil end of transformer life
Action taken: The transformer was scrapped

Case Nr. 5: 340 MVA-, 245 kV - ST, manufactured 1977

Defective: Winding Contamination
Fault Symptom: PD
Detected by: DGA, PD-Measurements (A, D)

History:

Over a period of 20 years this transformer has been in service troublefree at the same station. Then it was moved to another station for one year where it was connected on an existing cooling plant. After its return a continuous increase of dissolved gasses was observed, especially hydrogen.

To clarify this, a RVM and a frequency-dependent impedance measurement were performed but without any defect indications. Then on-site partial discharge measurements were made by a PRPDA (Phase Resolving Partial Discharge Analyser). Two partial discharge sources of the same kind were clearly indentified at phase V and phase W (Table 5, Fig. 3).

Results m.-point	PD on Tap 1	PD off Tap 1	PD on Tap 19	PD off Tap 19
1 U	no PD	no PD	no PD	no PD
1 V	7,3 kV 500 pC	5,7 kV	8,2 kV	8,2 kV
1 W	11 kV 500 pC	7,6 kV	10,2 kV	10,2 kV
1 N	7,3 kV	5,7 kV	8,2 kV	8,2 kV
2 v	no PD	no PD	no PD	no PD
2 w	no PD	no PD	no PD	no PD
2 u	no PD	no PD	no PD	no PD

Table 5 : Results of the on-site PD-measurements

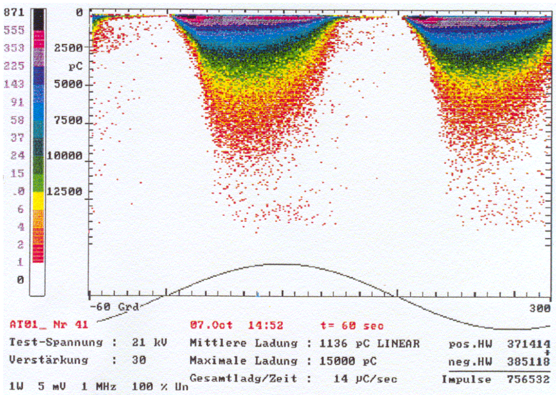


Fig 3: Example of PD Activity at Phase W (HV)

Because of these the transformer was returned to the manufacturer for dismantling The dismantling revealed a strong decontamination with particles and many discharge points especially at the upper end insulation of the hv-winding.

The discharges were caused by the particles from the inner coating of the tubing (Fig. 4) of temporary connected cooling plant.

Fig 4: Paint particles from the cooling plant, causing PD

Diagnosis: Severe contamination of all windings from the piping of a cooling plant, with severe PD tracking.

Action taken: Repair. New windings and cleaning of the cooling plant.

Case Nr. 6: 40 MVA-, 123 kV – ST with heat recovery in the cooling system, manufactured in 1981.

Defective cooling system
Fault Symptom: Malfunction of the cooling system, excessive fault gases from thermal cellulosic degradation, elevated furane values
Detected by: Furanes, DGA (A, E)

History:

2002 a routine DGA (preventive maintenance) indicated a thermal problem (an elevated level of fault gases from thermal-oxidative cellulosic degradation, ratio carbon dioxide/carbon monoxide > 10, MSS Code 11122).

An immediate inspection of the cooling system revealed a defective magnetic valve, which had blocked the whole cooling system. The incident seemed to have happened quite recently prior the sampling for DGA, because no change in the oil numbers and a low level of furanes could be detected.

A DGA, oil- and furane analyses (Table 6) have been performed in intervals of 1, 2 and 6 months.

Para-meter	Ppm on 14.03.02	1 month later	2 months later	6 months later
Acidity (mg KOH/g)	0,11	0,10	0,15	0,11
Water (mg/kg)	32	25	18	26
2-FAL (mg/kg)	0,06	0,83	0,82	0,65

Table 6: Time Development of the Oil- und Furane values after a Problem with the Cooling System

The oil analysis showed no change, because the overheating was evidently time-restricted. The development of DGA and furanes was indicative for the overheating. One month later it could be seen, that the carbon dioxide content rose further and there was a strong increase in 2-FAL – 0,83 mg/kg oil. The furanic compounds are formed in paper and it takes some time because of the diffusion processes until an equilibrium with the fluid system has been established. The amounts of carbon dioxide and furanes stayed constant for approx. 3 months and then went back slowly.

Furanes and among them 2-Furfural can be used as indicators for thermal overheating. Their concentration rises soon after a thermal problem. However furanes are not stable in an air breathing system and are being further oxidized by air. After the thermal stress disappears, the furane concentration decreases as well.

This is an excellent example of how effective preventive maintenance can be.

This transformer would have been severely aged due to thermal overheating, caused by a blocked cooling system.

Diagnosis: Degradation of the insulation system as a sequence of a short time overheating.

Action taken: Repair of the magnetic valve
Now the transformer operates troublefree.

<u>Case Nr. 7: 234 MVA-, 345 kV - ST, manufactured in 1991.</u>

Defective winding
Fault Symptom: Elevated DC-Resistance
Detected by: DGA, DC-Resistance Measurement (A, F)

History:

After 11 years of service, rising amounts of fault gases from thermal oil decomposition with small amounts of acetylene have been detected by DGA (Table 7). Furthermore the ratio carbon monoxide/carbon dioxide was < 3, which suggested an electrical degradation of cellulose. The transformer was inspected on site. A resistance measurement was carried out. There was a remarkable increase in the DC-resistance. The transformer was sent for repair in the factory.

One broken twin conductor of two twins with burnt out insulation paper was detected. The damage location was a defective solder joint. The damage location has been a localized thermal source, because the DP-value of neighbouring insulation paper was not affected.

Fig 5: A broken twin conductor as a consequence of a defective solder joint

Type of gas	ppm (v/v)
Hydrogen	1060
Methane	2481
Ethane	703
Ethylene	2187
Acetylene	4
Carbon monoxide	450
Carbon dioxide	995

Table 7: Last DGA before taking out of service

Diagnosis: Defective solder joint

Action taken: The winding was repaired and the transformer was taken in service again and is working troublefree.

Case Nr. 8: 60 MVA-, 123 kV- Compensating Reactor, manufactured in 1979.

Defective insulation system
Fault Symptom: Sludge in oil
Detected by: DP, furanes, oil analysis (A, B, E)

History:

After 20 years of successful operation, time-based maintenance (DGA, oil and furane analysis) indicated severe ageing of oil and insulation. The reactor was brought back in the factory for refirbishment of the cooling system. DGA showed no failure indications (MSS Code 01002), but suggested a severe ageing of the solid insulation. The oil analysis revealed also a strongly aged oil (Colour 5,5, Neutralisation value 0,18 mg KOH/g oil) with sludge formation. The sludged oil has plugged the cooling ducts of the radiators and led to overheating. The paper samples of the winding were covered heavily with sludge and the DP-value was only 200. The measured furanes showed values of 2-FAL of 11,5 mg/kg oil. The solid insulation has reached the end of life.

Diagnosis: accelerated ageing of the insulating system as a consequence of inadequate cooling.

Action taken: A complete refirbishment was carried out – winding, oil, cooling system.

Case Nr. 9: 60 MVA-, 123 kV - ST

Defective OLTC [8]
Fault Symptom: High surface and DC resistance, excessive fault gasses from thermal oil degradation
Detected by: DGA, DC-Resistance, Surface Resistance Measurement (A, F, G) [8]
DGA indicated high amounts of fault gases from thermal oil degradation.

History:

The DC resistance measurements taken on the OLTC showed that only marginally increased contact resistance could be determined in the entire tap selector area. After a few switching operations had been carried out they were reduced to the normal level and did not show any current dependency. However, unusually high and unstable contact resistances were determined at the change-over selector. For this case a special surface resistance measurement was developed. Even after an increased number of change-over selector operations, the resistance values did not show any improvement. This behaviour indicated quite a heavy coke layer on the contacts, which could not be removed by simple switching. The transformer was opened, the selector was inspected and the change-over contacts were exchanged. The change-over contacts were covered with a thick carbonized layer with a significant surface erosion – see Picture. Such contact damage mainly appears on change-over selectors made of copper (movable contact) and brass (fixed contact) which are rarely operated. Caused by the slight tarnish, the contact resistance increases, and, consequently, the temperature of the contacts, too. The increased contact temperature accelerates the growth of tarnish and the temperature is high enough to decompose the oil and oil carbon is generated (Fig 6). In the course of time heavy layers (oil carbon) will be built up.

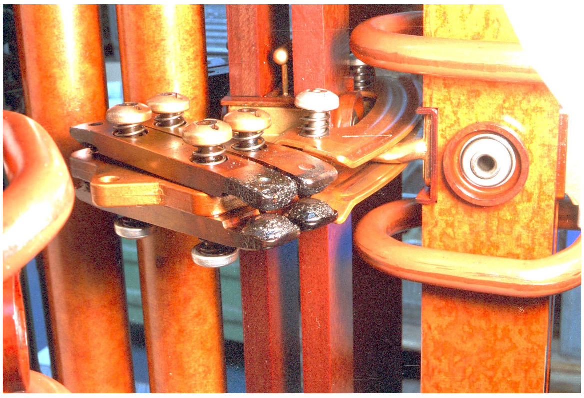


Fig 6: Eroded contacts of the tap selector with a coke layer.

Diagnosis: Oil-carbon layer on the copper and brass selector-over contacts.

Actions taken: Exchange of the contacts, on-site repair with consequent oil degassing.

Case Nr.10: 175 MVA-, 525 kV - GSU, manufactuing year 1997

Defective Winding
Fault Symptom: In disc short circuit, due to contamination.
Detected by: Mechanical Defect Recognition (Transfer Function Analysis), DGA

History:

Shortly after energizing 1999, the transformer failed in the HV-winding of phase U between the 2nd and 3rd disc at the lower end of the 500 kV main winding. The failure has been most probably caused by a foreign particle (piece of sealing material, paint etc) which was moved into the winding by OD-cooling.

For this case, the transfer function method was applied to identify this winding effect. The transfer function:

$$T(f)=\frac{U2}{U1}(f)$$

was analyzed in the frequency domain (Fig. 7) and it clearly showed a significant deviation for phase U against Phase V and W. This clearly coincides with the defect found during disassembly.

Diagnosis: DGA, interdisc short circuit at 2nd/3rd disc at the ground side of HV winding with a secondary effect of an axial flashover due to excess gas generation.

Actions taken: Due to the heavy contamination of carbon the complete set of phase windings on phase U/LV/HV regulating winding was replaced.

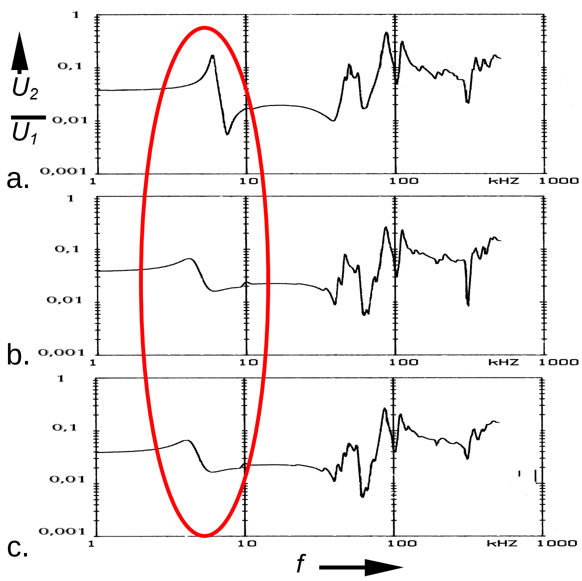


Fig 7: Transfer Function Analysis of a 175 MVA/520 kV GSU Transformer

a) Transfer Function of Phase U
b) Transfer Function of Phase V
c) Transfer Function of Phase W
d) Excitation and Response Signals U1, U2

Case Nr. 11: 380 MVA-, 245 kV - GSU, manufacturing year 1968

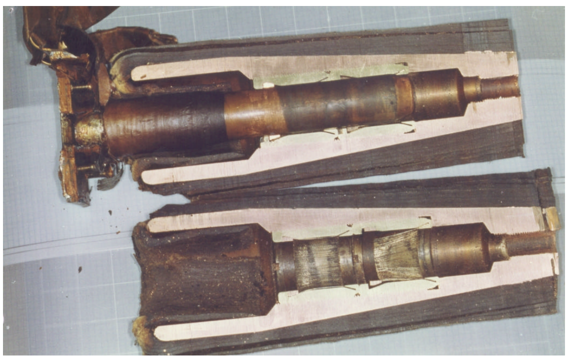
Defective insulation system
Fault Symptom: Excessive fault gases from cellulosic and thermal oil degradation
Detected by: DGA (A), DP (E)

History:

The DGA carried out 1991 in the course of the preventive maintenance showed high values for carbon monoxide and carbon dioxide, which indicates a thermal-oxidative cellulosic degradation. The ratio CO_2/CO was higher 10, the MSS Code 01132 – indicated a thermal problem with an involvement of the solid insulation. A local overheating of the connectors on the high voltage winding was identified as problem.

The DP values of the insulation at the connectors was between 150-250, i. e. It has reached its end of life (Fig 8a and b). The DP values on the low voltage lead was 500 -600. Since this is a GSU of a nuclear power plant no further risks were taken and the unit was replaced by a new transformer in 1993.

a)



b)

Fig. 8a, b : Connectors with fully burnt out solid insulation

Diagnosis: Overheating of the connectors because of stray currents and consequent degradation of the cellulosic insulation.

Action taken: Scrapping of the transformer.

5. CRITICAL ISSUES RECOMMENDATIONS FOR FURTHER INVESTIGATIONS

The DGA is very powerful, but also very individual. There are only few „ready made" DGA evaluations. A long time comparison of earlier DGA and accurate reports of the transformer history (overload, cooling problems) are very important. The gas increase rates are more essential than the absolute values of the fault gases. In the case of acetylene, however, which is an indicator of high energy arcing or very hot thermal fault (> 1000°C) the absolute values should be the first warning sign and must not be neglected. If acetylene has been found in the DGA, additional samples should be taken to determine if additional acetylene is being generated. Very often the presence of acetylene is due to a leaky tap changer. In this case generally the concentration of acetylene is higher than the concentration of hydrogen.

If acetylene continues to increase, however, the transformer may have an active high energy internal arcing and should be taken out of service. Further operation is hazardous and may result in a catastrophic failure.

Some transformers develop in the first months of operation fault gases, mainly hydrogen, which could stem from partial discharges. IEC 60599 points out to such catalytic phenomena, e.g. reaction of metal surfaces, varnishes or other transformer materials [9] with the insulation oil. Some highly hydro-treated oils may also produce hydrogen at heating. [10]. Such „artifact" fault gases can be reliably detected in factory tests – „fingerprinting". Therefore these tests, together with the tests after commissioning and in the first months after commissioning are very important.

<u>**Case Nr. 12: 400 kVA-, 12 KV - Distribution transformer with a zink plated tank, manufactured in 1997, hermetically sealed.**</u>

No defective components, catalytic effects
Fault Symptom: Excessive Hydrogen Content in the Oil
Detected By: DGA (A)

History:

DGA (Table 8) indicates significant amounts of hydrogen which does not change significantly. The transformer does not have actually any failure Hydrogen is may be produced as a result of a chemical reaction of metallic zinc with oil and the small amounts of water, contained in it. In other cases varnishes may lead to some further fault gases in addition to hydrogen - e.g. methane. Such „artifacts" may simulate or overlap partial discharges.

Type of gas	**ppm (v/v)**
Hydrogen	488
Methane	1
Ethane	< 1
Ethylene	< 1
Acetylene	< 1
Propane	< 1
Propylene	< 1
Carbon monoxide	67
Carbon dioxide	222
Oxygen	5180
Nitrogen	23700

Table 8: A Typical DGA, caused through catalytic effects of zinc surfaces and oil

Diagnosis: Catalytic reaction of the oil with zinc-surfaces – no transformer fault.

Actions taken: Oil degassing. The hydrogen level stabilized and showed no further increase.

<u>**Case Nr. 13: 300 MVA-, 420 kV – ST**</u>

No defective components
Fault Symptom: Increasing hydrogen content
Detected by: Online hydrogen sensor (M)

History:

A 400kV/300MVA grid coupling transformer was put into operation after repair with a new active part and installation of an on-line monitoring system. After commissioning the content of hydrogen detected by the online monitoring system increased continuously (Fig. 9). An increase of oil temperature by special control of the cooling unit revealed that the concentration of hydrogen is only dependent on the oil temperature. A correlation with the load factor k could not be detected. Therefore, an abnormal condition like partial discharges or hot spots due to load current could not be possible. The reason for the generation of hydrogen is due to chemical reactions of the new transformer oil [10]. This behaviour during a transformer's initial operating period has become apparent as on-line monitoring has become common, and it has probably always occurred. Gas formation is most apparent in highly refined oils, probably because the hydrogen and hydrocarbon radicals there cannot react with any unstable structures, since there are no such structures. Also zinc in the pipes of the cooling unit can cause such an increase of hydrogen. An off-line dissolved gas analysis (DGA) to determine the concentration of the other components dissolved in the oil indicated no further gases than hydrogen. So evaluation of several variables by the monitoring system revealed that the generation of hydrogen is caused by chemical reactions and therefore in this case uncritical.

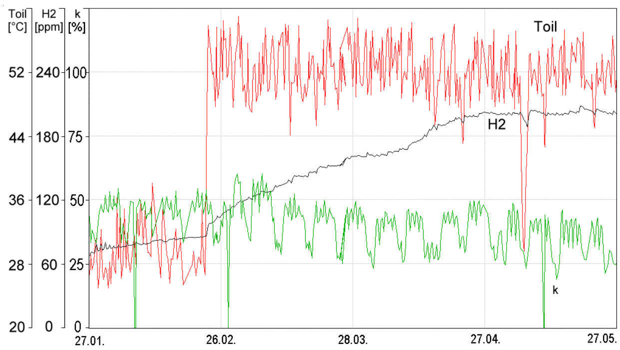


Fig. 9 : Hydrogen content dependent on top oil temperature

In Chapter 4 we presented 11 different defective and faulty cases, which could clearly be identified by the existing diagnostic procedures.

The two cases given here as example Nr. 12 and Nr. 13 are of peculiar nature and cannot readily be diagnosed without profound knowledge of physics and chemical processes.

The catalytic effects/interactions of highly hydrotreated oils with enamels/paints must always be considered as a possible source of interference of both DGA and oil analysis results.

RECOMMENDATIONS FOR FURTHER INVESTIGATIONS

Despite of the successful diagnosis, presented above, we still see the need for continued research to establish loss of life or to determine remaining life. The DP (Degree of Polymerization) is the best indicator for loss of life or remaining life determination. It has, however, the severe disadvantage, that it needs sample from within the transformer (leads, windings etc). Most of these samples cannot be taken from the hottest area – and are therefore not really representative.

Possible alternatives are:

- Dielectric Response Measurements (PDc Analysis) and
- Furan-derivate analysis.

Both methods are non-invasive and deliver excellent information on ageing effects. However, since Furane analysis depends highly on temperature and moisture and PDC results are highly influenced by oil conductivity we recommend to study the various impacts in more detail.

The ultimate goal should be to determine a correlation between:

- Relative Moisture (RM) and age/loss of life (DP)
- Furane Analysis and age/loss of life (DP)

Since it always takes at least two different diagnostic approaches to identify critical defects, we suggest to work on the

Correlation of RM and Furane Compounds and DP-Values.

Further efforts should also be addressed to the development of new, more stable sensors for hydrogen and other fault gases for on-line monitoring.

6. CONCLUSIONS

The total of 13 different cases of different faults and non faulty conditions of power transformers and reactors lead to the following conclusions:

1) The most powerful diagnostic tool is the DGA. It may be used to identify dielectric, thermal and chemical ageing problems.
2) Oil analysis as established in all facts is the second most powerful diagnostic tool.
3) It normally takes 2 or more different diagnostic approaches to really identify the nature of the defect.
4) The existing diagnostic procedures are mature and can also be used to identify defects in peripheral components (cooling plant)

5) Both off-line and on-line diagnostics can be extremely successful to avoid catastrophic and costly outages, if applied consequently.
6) Consequent maintenance, with fingerprinting and trend analysis and ad hoc on site diagnostic testing are indispensable for transformer life management.

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