Transformer failures are costly

The Hillside aluminium smelter is located in Richards Bay, 200 km north of Durban, KwaZulu-Natal province, South Africa. The operation is fully owned and operated by BHP Billiton. Construction of Hillside Aluminium began in 1993 and Hillside's two potlines cast their first metal in June 1995.

by Ian Gray, Oilwatch Transformer Services

In February 2003, Hillside was expanded with a further half potline. First metal was poured from this half potline during October 2003. This increased production at Hillside from 535 000 to more than 700 000 tons per annum, making it the largest aluminium smelter in the southern hemisphere and South Africa's major producer of primary aluminium. It is one of the worlds most advanced and efficient AP30 smelters and produces T-bars and primary aluminium ingots.

The Hillside smelter consumes 1100 MW of electrical power, with approximately 147 installed transformers in 1995. The unit's capacity ranges from 90,8 MVA regulators/93,5 MVA rectifiers/35 MVA auxiliaries on the 132 kV system: 6,3 to 1,6 MVA on the 22 kV system and 600 to 200 kVA on the 3,3 kV systems.

Dissolved gas analysis (DGA) has been a widely accepted preventive maintenance tool for the electric power industry for over thirty years. Though DGA continues to be a vital component of assessing transformer condition, the demands imposed by the increased loading of transformers and the ageing of the transformer population require new assessment tools and diagnostic approaches. It has been suggested that over 70% of transformer condition information is contained within the insulating fluid and that many transformer failures are attributable to manageable problems. Many of these problems are identified only after a thorough understanding of the complex relationships that exist between DGA data and information obtained from analysing the insulating fluid in transformers.

Dissolved gas analysis (DGA) of oil samples is probably the most effective means of monitoring the condition of oil-filled electrical equipment such as transformers, for several reasons. Firstly, nearly every possible fault generates one or more gases arising from the consequential increased degradation of adjacent oil or cellulosic insulation, so DGA can be said to be comprehensive in responding to many faults. Furthermore, since in the early stages these 'fault' gases dissolve in the oil and can then be detected at some subsequent point in time when an

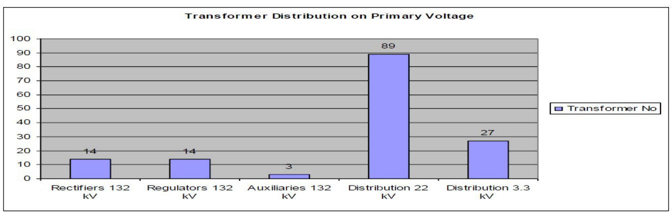


Figure 1: Transformer distribution on primary voltage

oil sample is taken, DGA can detect intermittent faults. Also, because fault gases can be detected at very low levels, the DGA technique is very sensitive and eminently suitable for detecting faults at an early stage. Most guides for interpreting DGA results include, and indeed concentrate on, schemes for diagnosing faults, usually by analysing the relative concentrations of the various fault gases, so the technique can also be described as discriminating and contributing to diagnosis as well as the detection of faults.

The main difficulty in making use of DGA results, which arises from its very good sensitivity, is that it is not easy to draw the line between normal and abnormal results, i.e., to be sure that a fault really exists. Most, but not all, interpretation schemes include a normal condition as one of the diagnostic outcomes but have not been particularly effective in reliably identifying a normal condition.

This article provides a summary of a fault in a furnace rectifier transformer that was detected by dissolved gas analysis at early life and will act as an aid and guide to the power engineer. "*When the transformer should be removed from service*" (See Figure 2).

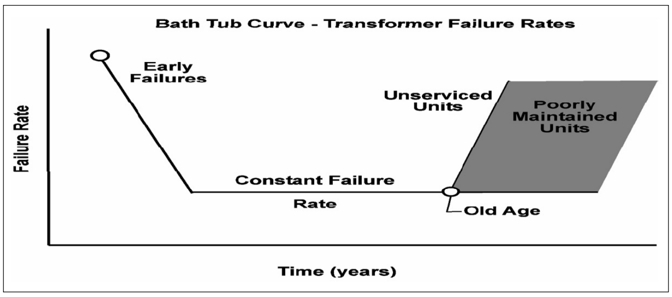


Figure 2: Transformer life cycle model

Transformer design and construction

Transformers are normally very reliable items of electrical equipment, but when faults occur, they can lead to the loss of what is usually the most expensive item of equipment in the substation. In addition, some faults can develop catastrophically, with the potential to cause substantial collateral damage to nearby equipment and posing a risk to personnel.

The modern power transformer is designed with far less insulation material and electrical clearances due to the pressure of driving down costs. This factor needs to be considered with the failure rate at the Hillside smelter. See Table1 comparing transformers between the 1970s and 1980s.

• 12% decrease in total weight
• 11% decrease in case weight
• 10% decrease in oil weight
• 13% decrease in core & coil weight
• 7 to 33% decrease in electrical clearances
• 9% decrease in no-load losses
• 3.5% decrease in load losses
• 25% increase in number of pumps

Table 1: Transformer comparisons between the 1970s and 1980s

What causes a power transformer to fail?

It is generally believed that failure occurs when a transformer component or structure is no longer able to withstand the stresses imposed on it during operation.

It is also important to distinguish the fault and the failure. A fault is mainly attributed to permanent and irreversible change in transformer's condition. The risk of a failure occurrence depends not only on the stage of the fault developing but also the transformer functional component involved. The failure could be repairable on site, depending on the type of fault as well as the severity of the failure.

Power transformer failures are commonly associated with localised stress concentrations (faults), which can occur for several reasons, including:

- Design and manufacture weakness, e.g., poor design of conductor sizing and transpositions, poor joints, poor stress shield and shunts, poor design of clamping, inadequate local cooling, high leakage flux, poor workmanship, etc.
- Weakness in transformer design, construction and materials could be covered by low loading. However, increasing loading and extended periods of in-service usage will uncover these weaknesses

Figure 3: Catastrophic transformer failure

In the event of failure, the force applied to the structure may approximate 360 PSI due to the steep wave front and high velocity, representing a loading sufficient to distort the container or shear the holding bolts and possibly cause a transformer oil fire.

Case example: rectifier transformer

The DGA on this transformer showed abnormal gas production of hydrogen, methane, ethylene and ethane about 20 months after energising. The fault condition was diagnosed as a thermal fault of medium temperature in the range 300°C and 700°C. The recommendation at 30/09/1996 was to remove the unit from service for inspection.

See Table 2 giving the name plate data and Figure 4 shows the DGA trend with Figure 5 showing the DGA signature.

Make:	TRAFO-UNION
Year Manufactured:	1995
Primary Voltage:	132 kV
VA Rating:	93.5 MVA
Vector Group:	111,D11+1
Secondary Voltage:	1060V
Tap Changer:	On Load
Oil Volume Litres:	33908
Conservator:	Yes

Table 2: Name plate data

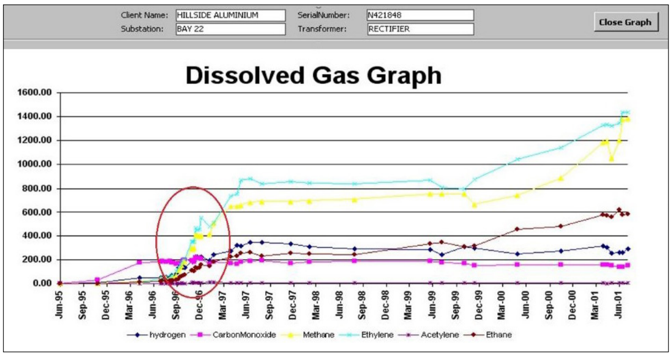


Figure 4: DGA trend up to July 2001

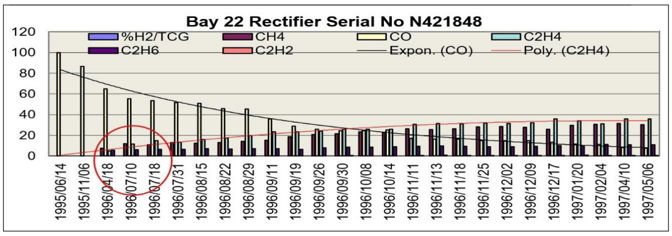


Figure 5: DGA Signature up to July 2001

Condition monitoring and failure event: Bay 22 rectifier

The manufacturer's contention was that, although this was not a normal gassing pattern, it was not serious enough to warrant removing the unit from service. The manufacturer's in-house expert advice was to monitor the gassing pattern until exponential increase was seen.

The exponential rise can be seen from 1996 to 1997.

The frequency of oil sampling was increased as the transformer was under warranty and the manufacturer ultimately had the decision on whether to remove a transformer from service for inspection. It is interesting to note the gas production after July 1997 showed only a slight rate of rise.

However, after the oil de-gassing in July 2001, the same phenomenon of exponential gas production followed by a levelling off was seen (See Figure 3). This can be explained in part by the IEC 60599 code that reports that there can be gas diffusion losses for in service equipment. However, there is no agreement concerning the magnitude.

There are also reports of gas adsorption by the solid (paper) insulation.

This transformer was ranked as having the highest risk of failure, based on the DGA-Total Combustible Gas Profile (See Figure 6). The condition was monitored by regular oil samples. On-line DGA was considered.

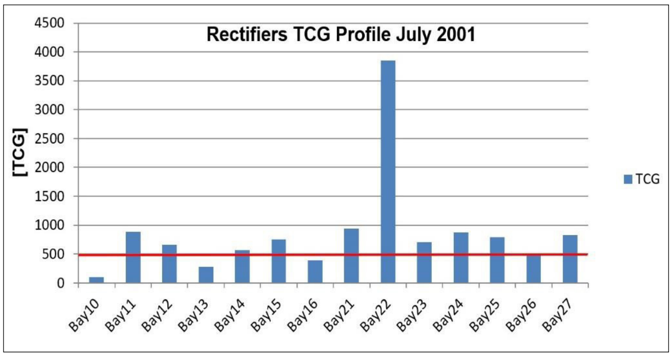


Figure 6: Total combustible gas profile at July2001

Failure event

At 16:32, on the 18 November 2005, Transformer T22 failed catastrophically. An urgent DGA sample confirmed that a discharge of high energy (arcing) had occurred (See Figure 7).

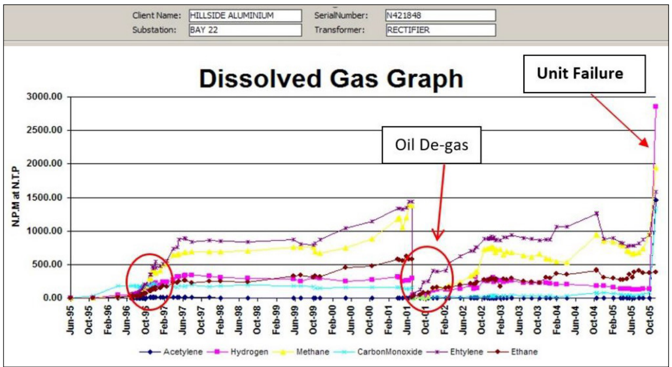


Figure 7: DGA trend

When T22 transformer failure developed, the entire sequence of events, equipment failures and trips were over in approximately one second.

- T22 faulted internally caused upstream circuit breaker to trip and simultaneously induced a high voltage in the rectifier and Potline 2 DC busbar system.
- The DC busbar system, now at elevated voltage, flashed over at the point of lowest insulation level. This happened to be at reverse current relays at T23 and T27, which had been supplied with metal screws instead of insulated screws originally.
- Effectively, as a result of the flash-over, potline voltage (1000 V higher) was "connected" to low voltage circuits at the rectifiers. This caused various low voltage equipment failures at the rectifiers and the loss of Potline 1 as well. (The 125 V DC supply is common between Potlines 1 and 2.
- The elevated voltage on the potline DC bus resulted in the insulation level of the pot micros being exceeded, damaging a number.

Figure 8: Damage to the HV winding

Fault type. Red phase, HV-LV-core-tank-earth fault

Consequence of the Failure

- 900 MW wiped off the National Grid
- Potline 1 offline for 75 min
- Potline 2 offline for 145 min
- Major impact to production (output and process stability)
- Damage to critical control circuits
- Loss of N-1 redundancy in transformer supply

Disaster averted

An outage of more than 180 min often leads to a prolonged shutdown of an aluminium plant – up to a year.

Zero injuries sustained.

Failure investigation

On the 21-12-05 the transformer HV and LV winding on the 'A' phase were removed and the core exposed.

'A' phase high voltage winding open circuit and flashed to core (See Figure 7).

The flash mark on the A-phase LV winding was on the outer surface of the disc at the bottom of the winding. The blocks underneath the winding showed movement as a result of the flash over between the A-phase HV winding and core.

Burning in the vicinity of the top core earth strap between A and B phases as a result of the fault currents during the HV flash over.

Overheating of the core. See Figure 9.

Figure 9: The sites of overheating

Mechanism of the flash-over and root cause

The production of gas in the HV winding seems to have leaked past the LV winding, affecting the dielectric strength of the oil between the LV winding and the tank. This resulted in a secondary flash-over from the LV winding to the tank.

The root cause was not established at this stage. To establish the root cause a tear down was planned for Bay 21 rectifier as this transformer was ranked as having the highest risk of failure of the surviving units

Investigation: Bay 21 rectifier

As part of the investigation, Doble Engineering was requested to electrical-test and review the DGA data. The findings are as follows:

The excitation current tests were performed at 1 kV for all phases. It was found that the exciting currents were higher than expected. The abnormal exciting currents generally are a result of two conditions which are as follows:

(a) Core related defects
  (i) Shorted laminations (increase in eddy currents)
  (ii) Circulating currents in the core, frame and tank
(b) Defective bolted or welded joints on current carrying parts.

The Sweep Frequency Response Analysis revealed significant problems with the HV winding.

The Doble DGA scoring system scores this transformer between 80 and 100. The DGA signatures are indicative of a localized thermal fault probably of the 'bare metal' rather than 'covered conductor'. This type of gas generation is indicative of the following:

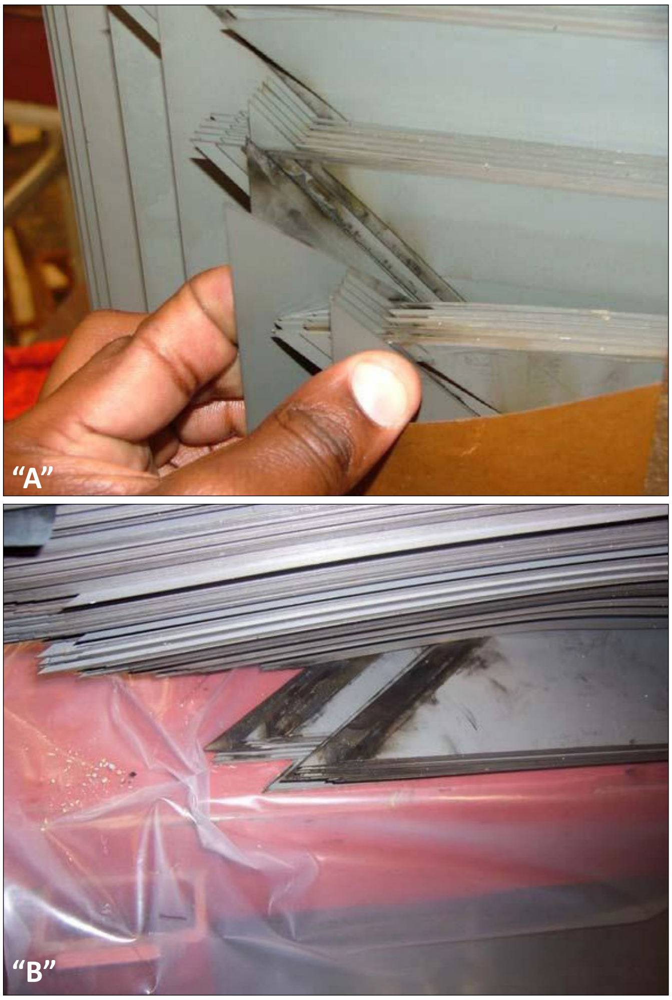
(a) General overheating, namely, abnormal rise of the oil temperature due to cooling deficiency, poor distribution of oil flow, core overheating
(b) Local core overheating associated with the main magnetic flux
(c) Local core overheating associated with stray flux
(d) Clamps in magnetic shields
(e) Current carrying connection as a result of joints which will increase contact resistance and oil overheating.

However, the absence of hydrogen and acetylene discounts any form of winding (paper) involvement and arcing/sparking.

Internal inspection and findings

- Striking resemblance of core defect between T22 and T21 (See Figure 10)
- Caused by stray magnetic fields induced by high currents on LV winding
- Field interaction with core at overlapping joints causes local heating
- Local heating gives rise to gassing

Root cause of gassing was attributed to a poor shielding design or reduced cross sectional area of core.



Figures 10 (A) and (B): The core overheating. A is T21 and B is T22

Conclusions

Fault and failure investigations on power transformer components have an important role in improving reliability and managing the risk of transformer failure. The identification of the primary cause of failure and the subsequent analysis enables recommendations for corrective action to be made that hopefully will prevent similar failures from occurring in the future.

When design error and/or weaknesses developing over time are uncovered, enhanced monitoring/investigation on sister units built by the same manufacturer will help in preventing future failures and therefore aid in managing the risk of unexpected failure.

Transformer manufacturers need to balance the cost of equipment with reliability.

The transformer problems at the Hillside smelter fit the Bath Tub Life Cycle Model.

The application of DGA was 100% successful in identifying the faults at early life. DGA oil testing is typically a critical first step in any power transformer analysis.

The DGA technique detects newly formed faults both accurately and consistently and will locate a fault that cannot be detected in any other way. When abnormal gassing patterns have been established the unit should be removed from service as soon as it is practically possible.

Document first year in-warranty problems before out of warranty failure. As one example, National Grid (UK) has reported, "A number of faults have been detected, although in each case the transformer had satisfactorily passed the routine tests"

CIGRE report 1984 states that "Dissolved-gas-in oil chromatographic is successfully applied to fault detection in the maintenance of large power transformers. Savings which could be achieved are in the region of hundreds of millions of US dollars.

Independent professionals and consultants are only able to offer their opinions.

Experience and understanding of the diagnostic methods are required to make DGA a more exact science and not an art.

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This article was presented to EuroTechcon 2011. The unabridged version can be found at: https://oilwatch.co.za/dissolved-gas-analysis-at-an-aluminium-smelter/

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