Practical Experience Gained from Dissolved Gas Analysis at an Aluminium Smelter

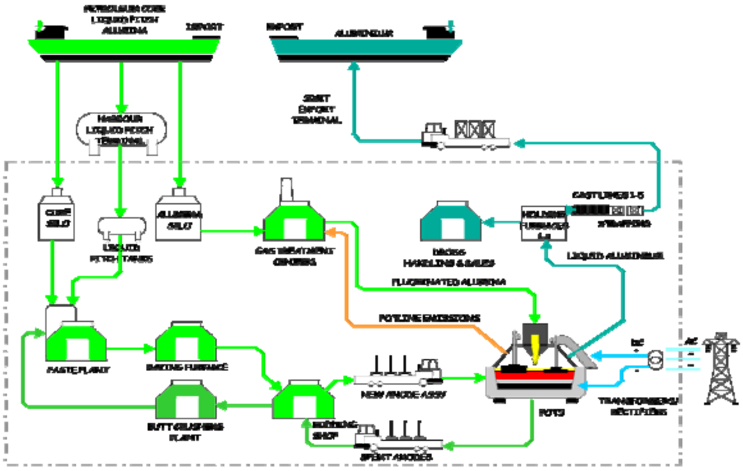
Ian.A.R. Gray
Transformer Chemistry Services

ABSTRACT:

The Hillside aluminium smelter is located in Richards Bay, 200 kilometers 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. Hillside's two plotlines cast their first metal in June 1995.

In February 2003, Hillside was expanded with a further half pot line. First metal was poured from this half pot line 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 1 100MW of Electrical power, with approximately 147 installed transformers at 1995. The units capacity range from 90.8 MVA Regulators/93.5 MVA Rectifiers/35 MVA Auxiliaries on the 132 kV system: 6.3 -1.6 MVA on the 22 kV system and 600-200 KVA on the 3.3 kV systems.

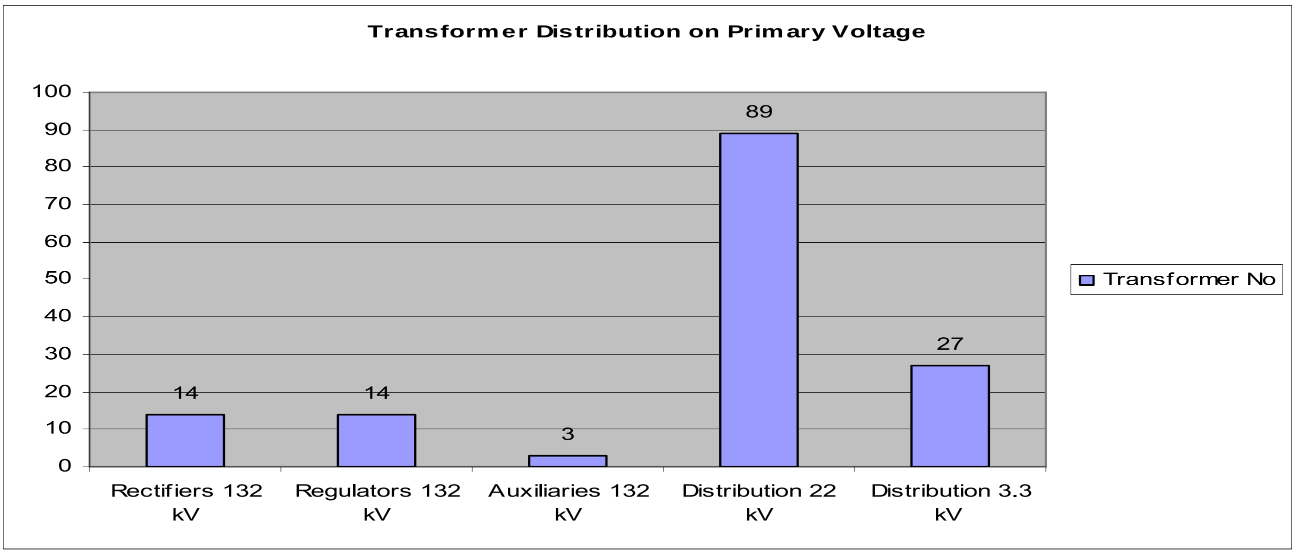


Figure 1- Transformer Distribution on Primary Voltage

INTRODUCTION

Dissolved Gas Analysis (DGA) has been a widely accepted preventive maintenance tool for the electric power industry for over thirty (30) years. Though DGA continues to be a vital component of assessing transformer condition, the demands imposed by the increased loading of transformers and the aging 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 analyzing 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. Further more, 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 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 paper will provide a summary of Hillside Smelter Transformer faults 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 Transformer Life Cycle Model

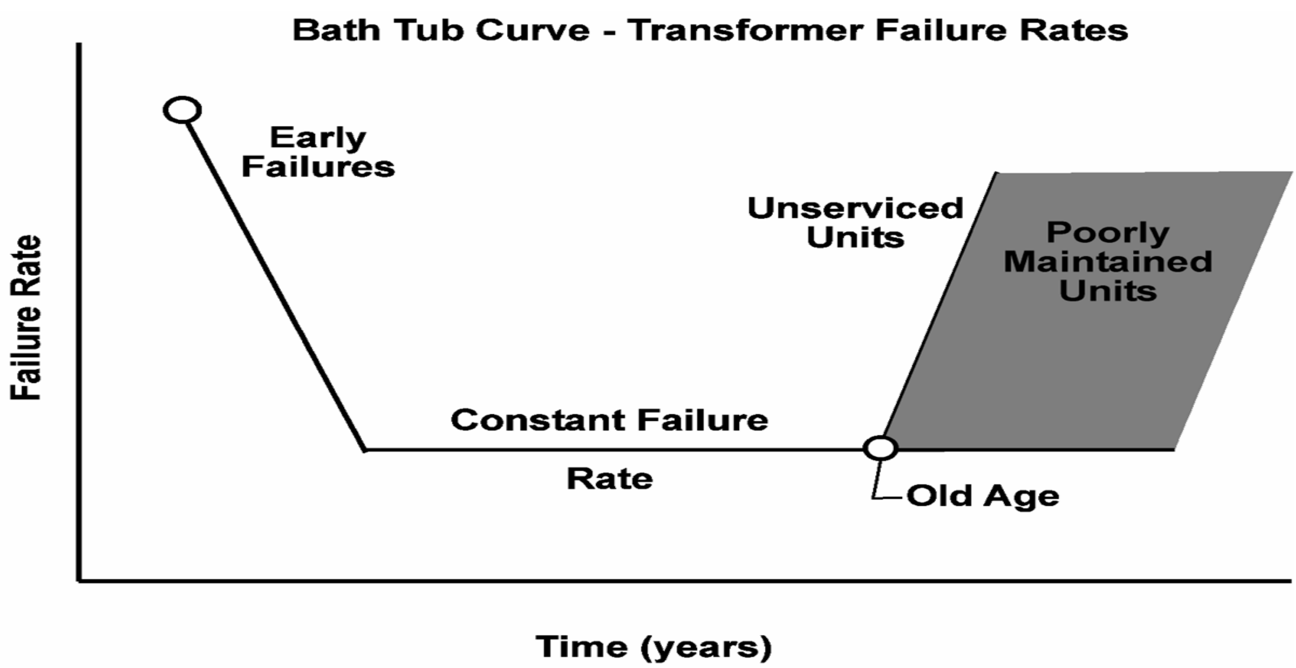


Figure 2- Transformer Life Cycle Model

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.

As electrical devices that transfer energy from one electrical circuit to another by electromagnetic coupling without moving parts, power transformers are normally regarded as highly reliable assets because they are designed and constructed by time-proven technology and materials. It is generally believed that the transformer designed and built at the turn of the 20th century was already a mature product as the essential features of the device remain unchanged to date, although the transformer continues to evolve.

The principles that govern the function of all electrical transformers are the same regardless of size or application. The typical power transformer is submerged in mineral oil for insulation and cooling and is sealed in an airtight metallic tank. Low- and high- voltage power lines lead to and from the coils through bushings. Inside the transformer tank, core and coils are packed close together to minimise electrical losses and material costs. The mineral oil coolant circulates by convection through external radiators. Figure 3 shows three winding assembly on core viewed from the HV side and after the tank being removed.

Figure 3-Three winding assemblies on core, HV side view

The essential parameters that characterise the ideal transformer depend, to a large extent, on the properties of the core. The properties that are critically important in transformer core materials are permeability, saturation, resistivity and hysteresis loss. It is generally believed that it is in the core that the most significant advances in power transformer design and construction have been made.

The performance of power transformers depends on dielectric insulation and cooling systems. These two systems are intimately related, because it is the amount of heat both the core and winding conductors generate that determines the permanence and durability of the insulation, and the dielectric insulation system itself is designed to service to carry off some of the heat.

It is vital that the insulation utilised in a power transformer must be able to separate the different circuits; isolate the winding core and outer case from the circuits; provide mechanical support for the electrical coils and withstand the mechanical forces imposed by power system surges and short circuits. Generally, Kraft paper has been utilised for winding conductor insulation, high density pressboard for inter-winding and inter-phase insulation, and crêpe paper for lead insulation.

The critical properties that determine the functional life of dielectric oil/paper insulation are chemical purity, thermal stability, mechanical and dielectric strengths.

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 Table 1 comparing transformers between the 1970's and 1980's

Table 1- Transformer Comparisons between the 1970's and 1980's

• 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

See Figure 4 showing how the design and construction of 1500 KVA transformer has changed from 1945 to 1970.

Figure 4- Transformer from 1945 to 1970

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.

Mechanisms of failure that are involved in a large transformer are often complex. Typical transformer functional failure mechanisms are summarised in Table 2, as per the CIGRE WG12.18. Note this is a functional failure model only for transformer core and coil assembly, not including on load tap changers (OLTC) and bushings.

It is also important to distinguish the fault and the failure. A fault is mainly attributed to permanent and irreversible change in transformer 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.

Table 2
Transformer functional failure model

System, Component	Possible Defect	Fault and Failure Mode
Dielectric system • Major insulation • Minor insulation • Leads insulation • Electrostatic screens	• Abnormal oil ageing • Abnormal paper ageing • Partial discharges • Excessive water • Oil contamination • Surface contamination	Flashover due to: • Excessive paper ageing • Destructive partial discharges • Creeping discharges • Localised surface tracking
Mechanical system • Clamping • Windings • Leads support	• Loosing winding clamping • Loosing winding	Failure of solid insulation due to: • Failure of leads support • Winding displacement (radial, axial, twisting)
Electromagnetic circuit • Core • Windings • Structure insulation • Clamping structure • Magnetic shields Grounding circuit	• Circulating current • Leakage flux • Ageing laminations • Loosing core clamping • Floating potential • Short-circuit (open circuit) in grounding circuit	Excessive gassing due to: • General overheating • Localised overheating • Arcing/sparking discharges • Short-circuited turns in winding conductors
Current-carrying circuit • Leads • Winding conductors	• Bad joint(s) • Bad contacts • Contact deterioration	Short-circuit due to: • Localised overheating

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.;
The microstructure of the material utilized may be defective right from the start, e.g. containing micro-voids, micro-cracks etc.
Corrosive attack of the material, e.g. sulphur corrosion on paper and conductor can also generate a local stress concentration.

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.

Dissolved Gas

Origin of gases in Transformer oil
Corona (partial discharge), thermal heating (pyrolysis) and arcing cause gases to be produced in insulating oil. This is due to the breakdown products of the oil under electrical and thermal (heat) activity.

- Partial discharge

Key gases: Hydrogen and methane
This is a fault of low level energy which usually occurs in gas-filled voids surrounded by oil impregnated material. Bubbles in the actual oil may cause a partial discharge, especially when the bubble is in a high electrical stress area. However, main cause of decomposition resulting in partial discharge is ionic bombardment of the oil molecules. The major gas produced is hydrogen and the minor gas produced is methane.

- Thermal Faults

Key gases: Hydrogen, methane, ethane and ethylene
A small amount of decomposition occurs at normal operating temperatures. As the fault temperature rises, the formation of the degradation gases change from methane (CH4) to ethane (C2H6) to ethylene (C2H4).

As the temperature increases so there is a gradual shift from methane to ethane gas generation. As the temperature increases further there will be a higher production of ethane and ethylene.

A thermal fault at low temperature, typically lower than 300° C, produces mainly methane and ethane with some ethylene.

A thermal fault at higher temperatures, typically higher than 300° C, produces ethylene. The higher the temperature becomes the greater the production of ethylene.

Extremely high temperatures ~ 1000° C may bring on the presence of acetylene.

- Arcing

Key gases: Hydrogen and acetylene
An arcing fault is caused by high-energy discharge. In most cases the discharge has a power follow through. In arcing, the major gas produced is acetylene. Power arcing can cause temperatures of over 3000°C to develope. If the cellulose material (paper, insulating board etc.) is involved, carbon monoxide and carbon dioxide are generated.

- Cellulose Aging

Key gases: Carbon monoxide and carbon dioxide
A normally ageing conservator type transformer should have a CO_2/CO ratio of about 7. Any CO_2/CO ratio above 11 or below 3 should be regarded as perhaps indicating a fault involving cellulose provided the other gas analysis results also indicate excessive oil degradation.

Interpretation of Dissolved Gas Analysis (DGA)
There are various international codes and guidelines on interpreting DGA data. The guidelines show that the interpretation of DGA is complex.

Ratio Methods

Dornenberg Ratio Method
One of the earliest methods in which two ratio of gases are plotted in a log-log axes

IEC 60599 Ratios
IEC 599 is the most up to date of the ratio methods. This method uses only three ratios as opposed the four used in the Rogers ratio method.

Rogers Ratio
The Rogers Ratio method uses four ratios of dissolved gas concentration to generate a code that will determine the nature of the fault.

Duval Triangle
This method is a more graphical method than the ratio methods previously discussed. Each of the gases is calculated into a ratio. These values are then plotted on the triangle. The point of interception falls into a zone in the triangle which depicts the fault the transformer is experiencing.

Gas Concentration limits

The IEC 60599 serves as a good guide. The tables based on voltage classification and transformer type can be used as a quick reference to determine if further investigating is required. There are numerous International guidelines.

Key gas Method

Thermal Oil: Decomposition products include ethylene and methane, together with smaller quantities of hydrogen and ethane. Traces of acetylene may be formed if the fault is severe or involves electrical contacts. Principle gas – Ethylene. See Figure 5- Overheating Oil

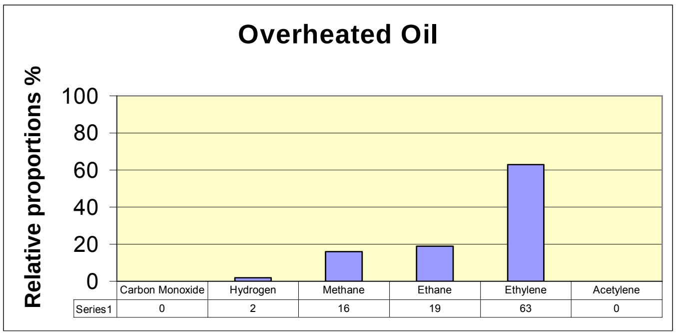


Figure 5- Overheating Oil

Electrical Corona: Low energy electrical discharges produce hydrogen and methane, with small quantities of ethane and ethylene. Comparable amounts of carbon monoxide and dioxide may result from discharges in cellulose. Principle gas – Hydrogen. See Figure 5-Corona in Oil

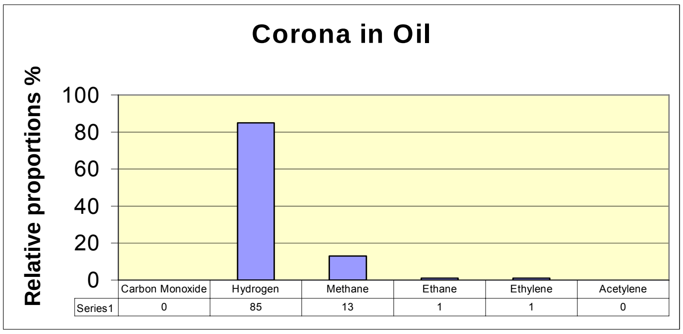


Figure 5-Corona in Oil

Thermal Cellulose: Large quantities of carbon dioxide and carbon monoxide are evolved from overheated cellulose. Hydrocarbon gases, such as methane and ethylene, will be formed if the fault involves an oil impregnated structure. Principal Gas – Carbon Monoxide. See Figure 5-Overtheated Cellulose

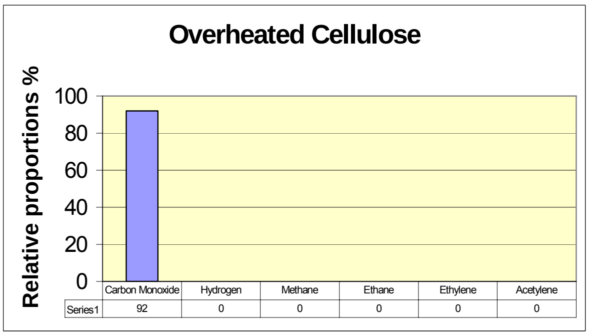


Figure 5-Overtheated Cellulose

Electrical Arcing: Large amounts of hydrogen and acetylene are produced, with minor quantities of methane and ethylene. Carbon dioxide and carbon monoxide may also be present if the fault involves cellulose. Oil may be carbonised. Principle gas – Acetylene. See Figure 6-Arcing in Oil.

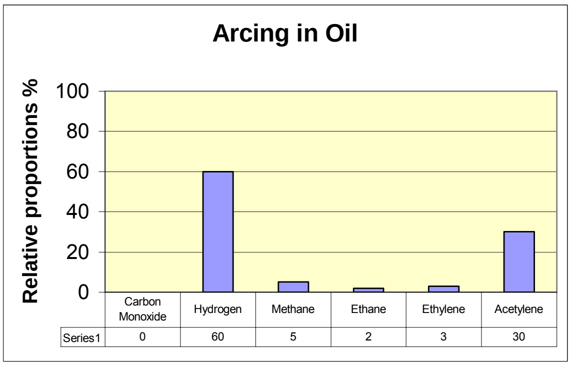


Figure 6-Arcing in Oil

Condition Codes

Total Dissolved Combustible Gases (IEEE C57.104-1991)
Actions based on sampling intervals and Operating for Corresponding Gas Generation Rates

This method was developed by IEEE society, and covers not only the determination of a fault severity and its nature, but also offers some indication to the follow-up action that is necessary.

Daily Production Rate Method.
This method calculates the daily rate of gas increase between samples. The IEC 60599 gives reference values.

Advantages and Disadvantages

The advantages and disadvantages of the various Codes and guidelines are listed in the Tables 4 to 10.

Table 3-Rodgers Ratio

Advantages	Disadvantages
Has the ability to ignore small laboratory errors	Unable to diagnose multiple faults.
Uses three or four ratios (the 3 ratio method is the latest method and the 4 ratio method an older version of the Rogers ratios).	Complex to calculate. Ratios can render codes that have no comment
Comprehensive diagnosis comments.	Sufficient gases are needed.

Table 4-IEC 60599 Ratios

Advantages	Disadvantages
Has the ability to ignore small laboratory errors.	Unable to diagnose multiple faults.
Uses three ratios.	Complex to calculate
Comprehensive diagnosis comments.	Sufficient gases are needed (gases need to exceed minimum level)
Internationally recognized	Ratios can render codes that have no comment.
Continuously upgraded by IEC committee	

Table 5-Dornenberg ratios

Advantages	Disadvantages
Has the ability to ignore small laboratory errors.	Has only three levels of diagnosis, thus very limited
Uses four ratios	Complex to calculate
Has diagnostic values for pure gas (not DGA)	Sufficient gases are needed (Gases need to exceed minimum levels).
	Ratios can render codes that have no comment

Table 6-Duval Triangle

Advantages	Disadvantages
Graphic in interpretation	Difficult to construct
Easy establishment of the problem	Time consuming if done by hand
	Misleading interpretation at very low concentrations of gas.

Table 7-Key Gas Analysis

Advantages	Disadvantages
Simple to use	Unable diagnose multiple faults easily
Graphic representation	Sensitive to fluctuation in sample analysis

Table 8-Gas Concentration limits

Advantages	Disadvantages
Simple to use	Does not take production rate into account.
Set limits indicate typical fault	Simplistic in approach does not take a combination of gases into consideration
	Does not take volume of oil into account.
	Sensitive to fluctuation in sample analysis.
	Needs to be used in conjunction with production rates.

Table 9-Production per Day

Advantages	Disadvantages
Rate of change	Needs to be related to oil volume (limits are calculated for 50 m3)
Determines risk (how quickly the fault is occurring)	Does not take a combination of gases into consideration
Simple to use	Sensitive to fluctuation in sample analysis.
Quick calculation.	

Table 10-Trend analysis

Advantages	Disadvantages
Individual or combination gases can be analysed.	Sensitive to fluctuation in sample analysis.
Points / samples can be removed	Time consuming.
Production can be seen	Knowledge of sample interpretation needed.
Graphic representation	Misleading if incorrect principals are used

NEW DGA DIAGNOSTIC METHODS

Doble DGA Scoring System

The Doble method of interpreting dissolved gas analysis results is seen to tackle the main weakness of existing schemes i.e. the difficulty of defining a normal condition. A simple scoring system based on results from known problems is used to provide a consistent and objective assessment of the seriousness of results, to improve the effectiveness of life management decisions. See Figure 7.

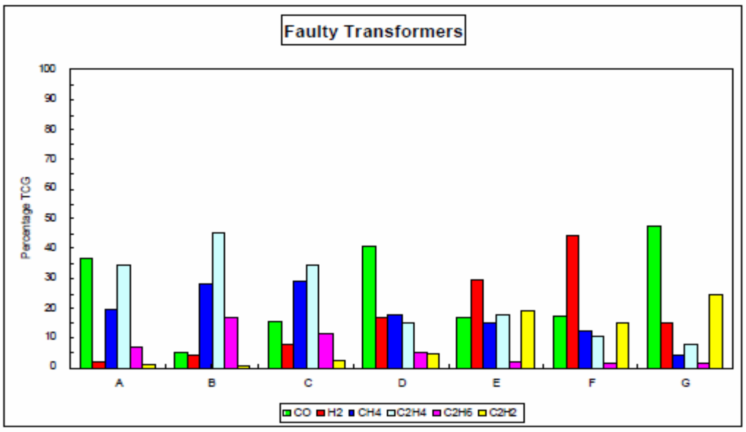


Figure 7-Doble scoring system

In this scheme, DGA results for normal transmission and generator transformers would be expected to return a score of no more than about 30, whereas a core circulating current would rate about 60 and more serious problems would score around 100 or higher. The scoring algorithm used is a product of both 'quality' (dependent on the gas signature and ratios) and 'strength' (depending on absolute levels) functions, but is strongly influenced by the former.
Because of this the DGA score will usually increase if the absolute levels of the key diagnostic gases increase, but the most important factor resulting in an increase in score will be a change in the gas signature towards what is perceived as a more serious case. See Figure 8.

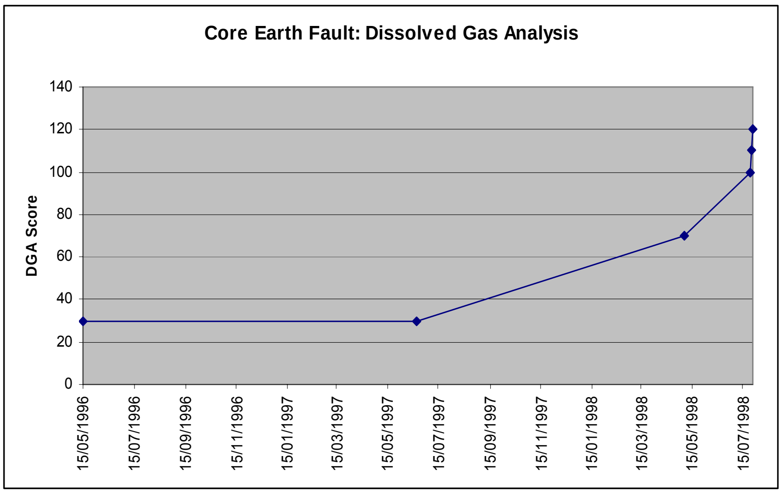


Figure 8-Doble scoring system

The Vector Algorithm

The Vector Algorithm is based on the chemical and physical principles of the Rogers Ratios and Duval Triangle. All three methods are consistent with Halstead's thermodynamic reasoning that with increasing temperature the hydrocarbon gas with maximum rate of evolution would in turn be methane, ethane, ethylene, and acetylene. The other gases usually present in an oil sample are notably hydrogen, carbon monoxide, carbon dioxide, moisture and air. The levels and proportions of all of these gases provide meaningful information on the operating conditions of the oil-impregnated insulation.

The new approach is not restricted to analyzing a single type of fault condition. These activities can occur at different intensities in different parts of the apparatus, in different time frames, or even concurrently in the same component. For example, it is conceivable that a partial discharge activity could be a precursor to limited or full-fledged arcing. A hot-metal fault is likely to be surrounded by regions at somewhat lower temperature. See Figure 9.

These coefficients can be adjusted to allow for various factors, such as the type and age of the equipment. Each of the condition levels, such as PDO = a (PDO), can be viewed independently or as a sum, C_V indicating the overall condition of the insulation.

$C_V = a(PDO) + b(ARC) + c(OHC) + d(OHO) + e(PMO)$

The new approach is best demonstrated using charts showing the five Vector Condition Levels on the same time scale. In practice, the algorithm is also used to assess episodes of fault development based on incremental changes and rates of gas production.

As an example, if we look at the historical DGA results of a transformer, we see that all of the hydrocarbon gases show an abrupt increase in September 2003. However, it is difficult to see from this graph what type of fault is developing. See Figure 9.

If we look at Vector method, we can see that a major PMO fault has developed. There are also signs of PDO, suggesting a worsening situation. The primary diagnostic, using this new approach, is consistent with the Duval Triangle and the IEEE Rogers Ratios, both of which indicated a "Thermal Fault >700°C". See Figure 10.

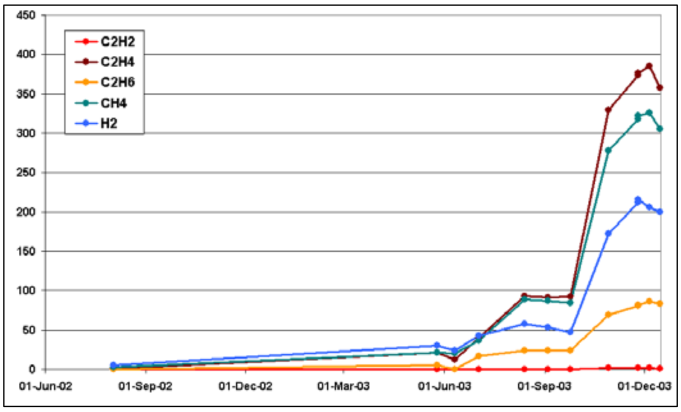


Figure 9-Historical DGA results of a transformer

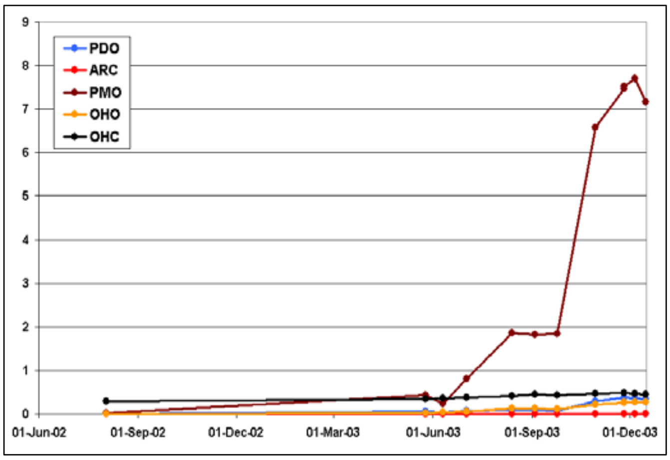


Figure 10-Vector Method

The Electrical Overview of the Hillside Aluminium Smelter is given in Figure 10

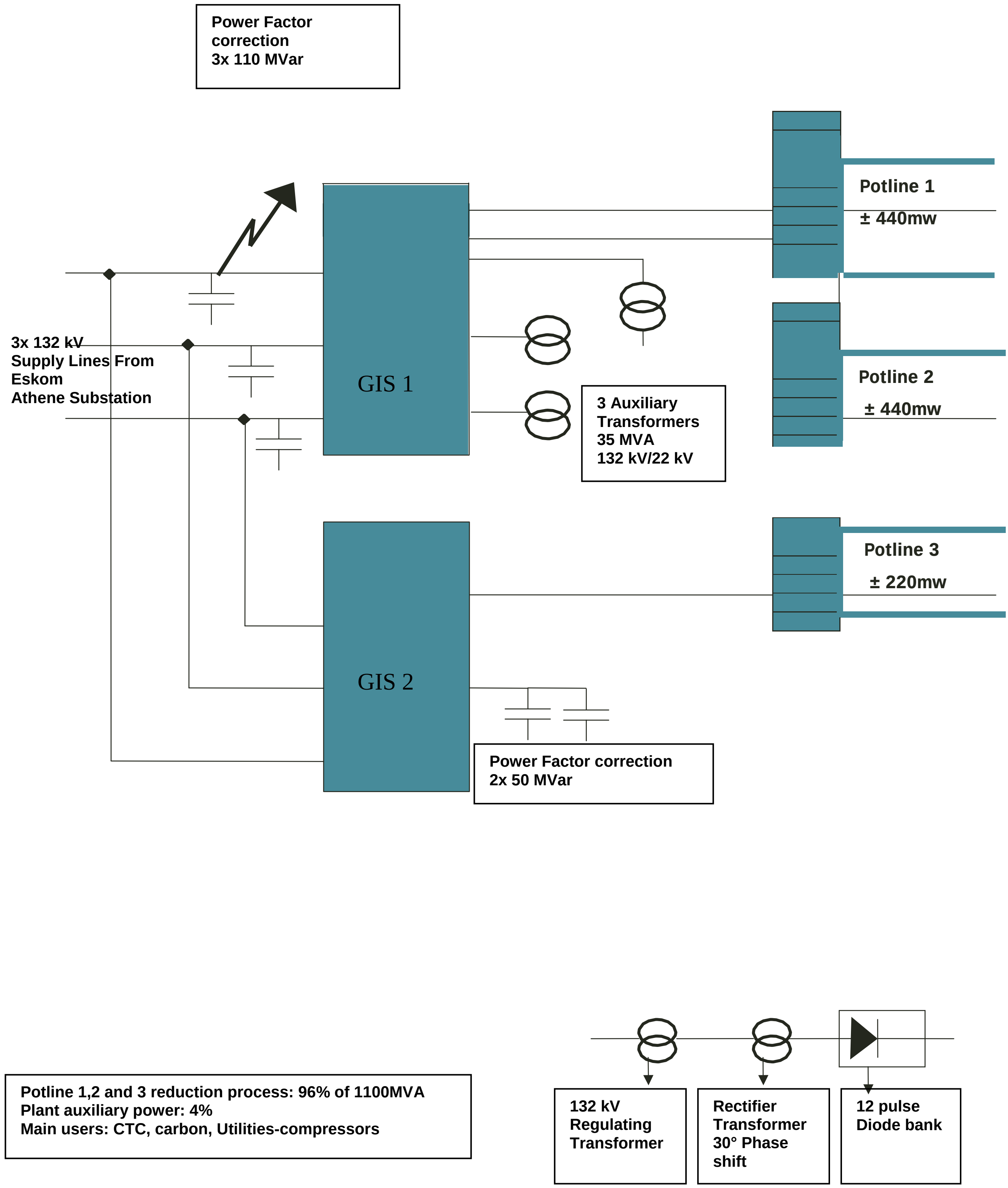


Figure 10- Electrical Overview of the Hillside Aluminium Smelter

Failure Event Regulator Transformers.

On the 25th March 2005, the Regulator Transformers from BAY 12 and 21 tripped when under going energised testing without Load. The trip occurred due to the supply cables being cross phased at the Pot room.
The nameplate information for the Regulator transformers is as follows in Table 11.

Table 11-Regulator transformer nameplate data

Make: TRAFO UNION	Year Manufactured: 1994	Primary Voltage: 132 KV
VA Rating: 90.8 MVA	Vector Group: YNo2.5,d15	Impedance: 0.69%
Tap Changer: On Load	Oil Volume Liters: 35057	Conservator: YES

Insulating oil samples were sent for urgent DGA testing. Samples had been taken on the 03rd March 1995 prior to energisation for compliance to IEC 60442 and to establish a DGA base line. The results listed Table 12 shows clearly the significant increase in DGA, indicating that both Regulator transformers had internal damage of an Arcing condition.

Table 12-Bay 12 and 21 Regulator transformer DGA data

	BAY 12	BAY 12	BAY 21	BAY 21
DGA ppm	06/03/1995	25/03/1995	06/03/1995	25/03/1995
Hydrogen H_2	0	772	0	468
Methane CH_4	0	155	0	131
Ethylene C_2H_4	0	61	0	237
Ethane C_2H_6	0	179	0	17
Acetylene C_2H_2	0	**171**	0	**541**
Carbon Monoxide CO	24	14	38	59
Carbon DioxideCO_2	203	249	249	205
TCG	24	1422	38	1453

DGA Diagnostics

The IEC 599 Ratios indicated a Discharges of High Energy in both cases
Typical examples: Discharges with power follow-through. Arcing-breakdown of oil between windings or coils to earth. Selector breaking current.

The Key Gas method showed Arcing in Oil as did the other Ratio methods. The Gas concentration method would be confusing due to the high levels of gas.

There was significant gas increase in both units with the IEEE (c57.104-1991) giving a Condition 2: OPERATING PROCEDURE-Exercise extreme caution. Plan outage.

The recommendation was for an internal inspection of both units.

Internal Inspection

As the transformers were under warranty the inspection was conducted under the direction of OEM.
It was found that there was major damage to the internal 22kV reactor in both cases. The concern was that transformers should have been able to with stand the fault condition, this required further investigation. Unfortunately no photographs were allowed by the OEM as this was a new design that had resulted in them being awarded the tender, based on price. They did not want any competing Manufacturer to have access to this design.

Root Cause and the next step

The root cause was found to be a weakness in the Regulator transformer design. This had significant cost implications. The manufacturer had to change the design to an External 22kV Reactor for each Regulator transformer, which had later implications. Also one additional Transformer Bay was required for Pot line 1 and 2 at a cost of approximately R 70 Million per transformer bay.

Failure Event Interconnector.

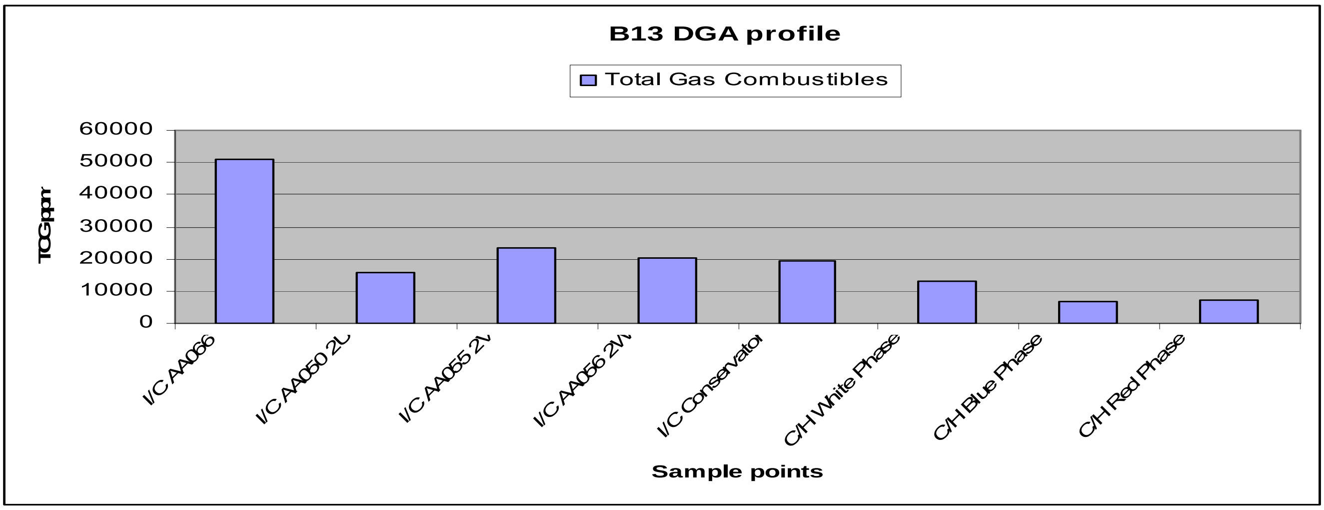
On the 23rd October 2005, a gas alarm was triggered by the Buchholz relay on the Interconnector system. The Interconnector links the Regulator and Rectifier through a system of oil filled compartments using paper insulated copper conductor. This event occurred approximately 6 months after energisation. See Figure 11 showing the how the Rectifier and Regulator Transformers are interconnected; the Cable Housing is to the right of picture.

Figure 11-Interconnection system for the Rectifier and Regulator Transformers.

The OEM suspected a Corona (Partial Discharge-PD) problem on the Cable housing to be the cause of the gas generation. The repair of this kind of fault would involve a lengthy outage with specialist staff and equipment that would have to been flown in from Germany.

Samples were taken of the Buchholz gas and oil from the various sample points on the Inconnector system. The strategy was to use the DGA to classify the type of fault condition and to identify the compartment with the fault. There is very little oil circulation in the inteconnector so in theory the fault would be in the compartment with the highest gas concentrations. The Total Combustible Gas (TCG) levels as Listed in Table 13 show clearly that the location of the fault was not in the Cable Housing but at sample point (AA066), the main compartment between the transformers.

Table 13- DGA profile of samples



Diagnosis of DGA results

The results of the Main Compartment sample point AA066 where the greatest Dissolved Gas in oil were found is compared to the sample taken of the Buchholz gas. See Table 14.
It is necessary to convert the concentrations of the various gases in the free state into equivalent concentrations in the dissolved state, using the Ostwald coefficients, before applying the gas ratio method, and to compare them to the dissolved gas concentrations in the oil of the relay and the main tank.

The calculation is made by applying the Ostwald coefficient (k) for each gas separately.
k =[gas in liquid phase] ÷ [gas in gas phase]

Table 14-DGA results of Buchholz gas and Main compartment

DGA ppm	Buchholz Gas	I/C AA066
Hydrogen H_2	12034	12299
Methane CH_4	25855	14892
Ethylene C_2H_4	16722	12220
Ethane C_2H_6	5120	11295
Acetylene C_2H_2	20	65
Carbon Monoxide CO	560	424
Carbon DioxideCO_2	2885	3733
TCG	51195	12299

IEC 599 DIAGNOSIS: Thermal fault of medium temperature range 300°C-700°C
Typical Examples: Local overheating of the core due to concentrations of flux. Increasing hot spot temperatures; varying from small hot spots in core, overheating of copper due to eddy currents, bad contacts/joints up to core and tank circulating currents

IEEE (c57.104-1991): Condition Code 4: OPERATING PROCEDURE-Exercise extreme caution. Plan outage.

Internal Inspection and findings.

The internal inspection of the Main Chamber found burnt (overheated) connections. See Figures 12A-B
The connections overheated because they had not been tightened to the Manufacturers specification.

(A) (B)

Figure 12-Burnt (overheated) connections

Root Cause and Savings

The root cause was found to be being non-conforming quality control during installation

Savings in the R Million range: By accurately diagnosing the fault type and location the manufacturer saved significant time and equipment to effect repairs. The smelter saved minimum down time on production

Predicted fault on the Reactor Transformers.

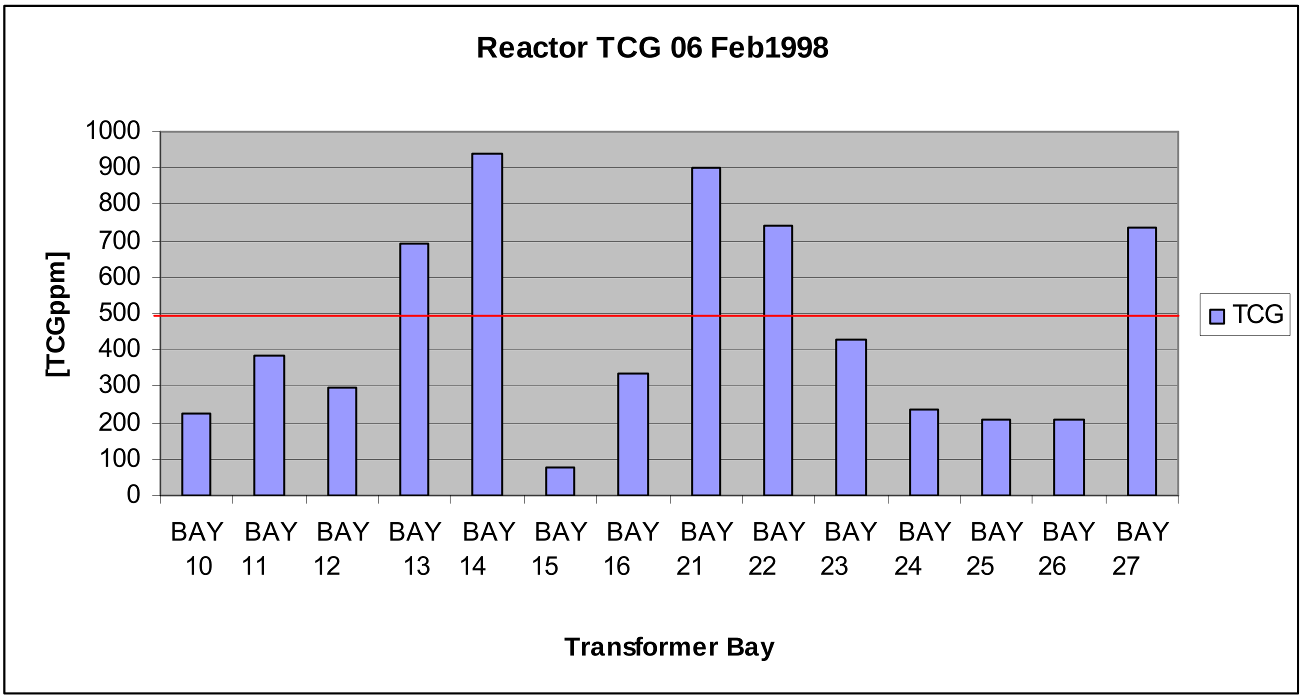
The program of installing External 22 kV Reactors onto the main Regulator started in July 1996. The Reactor name plate details are listed in Table 15. Insulating oil samples were taken prior and after Energisation in accordance to IEC 60422 with all results being normal. The transformers were then sampled on a regular basis as part of a Condition Monitoring program.

Table 15-Reactor transformer nameplate data

Make: TRAFO UNION	Year Manufactured: 1995	Primary Voltage: 22 KV
VA Rating: 1075 kVar	Oil Volume Litres: 2874	Conservator: YES

Routine DGA samples taken on 06/02/1998 showed a significant increase of Total Combustible Gas in a number of Reactors. See Table 16 showing the profile of results. The transformers from BAY 13: 14: 21: 22 and 27 showing the most significant increases.

Table 16-Profile of TCG results at 06 February 1998



Diagnosis of DGA results

The IEC 599 Ratio for transformers with Combustible Gas levels >500 ppm gave the fault condition as a Thermal fault of high temperature range >700°C.
The IEEE (c57.104-1991) gave a Condition Code 2 with the operating procedure in certain cases being to Advise Manufacturer or Plan outage.

It was recommended to remove one of these transformers from service for an internal inspection.

The manufacturer's contention was that these were normal gassing patterns for Reactor transformers as there was an internal resistor bank that generated heat during normal operation.

This theory is not supported by the Halstead model. The science behind gas production and temperature was published in J. Inst Petroleum 1973 by WD Halstead of CEGB R&D.
The evolution of gases from oil is a function of the Decomposition Energy (temperature).
In simple terms, from a Chemist's perspective, a Transformer is a chemical reactor that just happens to transform electricity.
The other anomaly was the different gas levels in the Reactors. If there was normal internal operation, the gas levels would be expected to be uniform.

The frequency of oil sampling was increased as the transformers were under warranty and the manufacturer ultimately had the final decision on whether to remove a transformer from service for inspection.

BAY 22 Reactor Transformer.

All the reactor transformers were sampled on a frequent basis following the significant rate of DGA rise in February 1998. The frequency of sampling was decreased when it was observed that the Dissolved Gas levels had stablised. However a sample taken on 20th July 1999 from BAY 22 Reactor showed a more than significant increase. A further sample was taken 24th July 1999 for confirmation and to monitor the Gas production. See Figure 13 giving the Graph trend. The results are listed in Table 17.

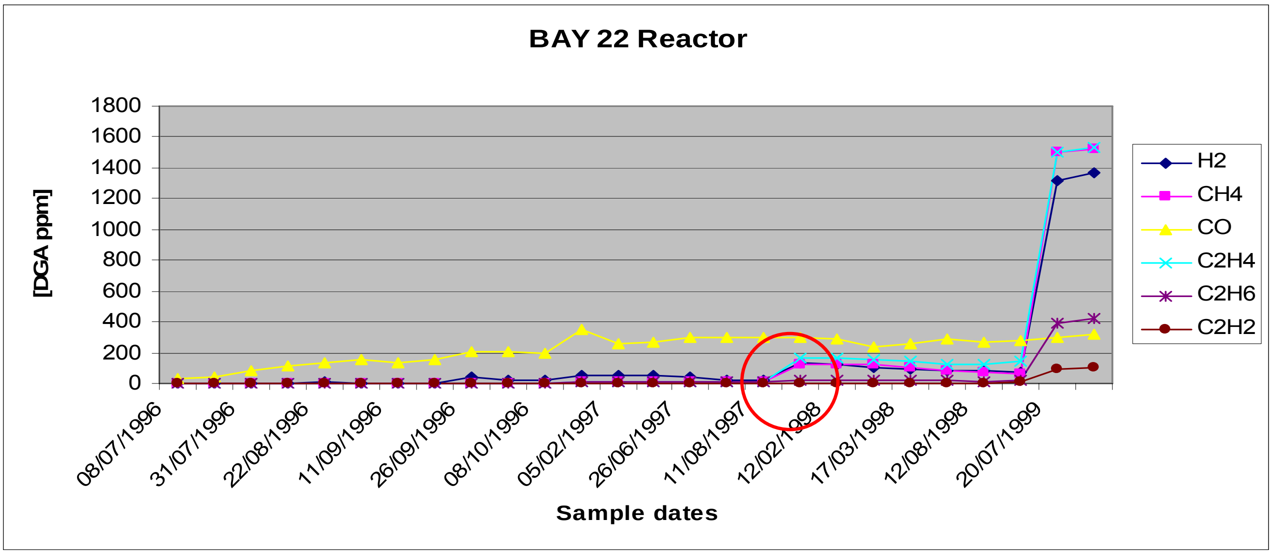


Figure 13 Graph trend of DGA data

Table 17-DGA from BAY 22 Reactor

Sample Date	H_2	CH_4	CO	C_2H_4	C_2H_6	C_2H_2
24/07/1999	1370	1520	316	1536	421	102
20/07/1999	1319	1497	295	1498	396	92
03/06/1999	70	65	279	139	19	7
12/08/1998	80	76	265	120	15	1
08/04/1998	81	83	291	123	16	3
17/03/1998	93	98	260	142	19	4
27/02/1998	102	119	238	151	20	4
12/02/1998	122	121	293	161	22	4
06/02/1998	131	120	302	165	22	4
11/08/1997	19	13	302	8	9	0
27/06/1997	24	10	297	9	9	0
26/06/1997	44	14	302	10	10	0
10/04/1997	51	15	265	12	11	0
05/02/1997	54	14	259	10	15	0
19/12/1996	47	15	352	14	12	0
08/10/1996	23	0	200	0	0	0
30/09/1996	21	0	210	0	0	0
26/09/1996	42	0	210	0	0	0
19/09/1996	0	0	154	0	0	0
11/09/1996	0	0	131	0	0	0
05/09/1996	0	0	156	0	0	0
22/08/1996	13	0	135	0	0	0
15/08/1996	0	2	116	0	0	0
31/07/1996	0	0	79	0	0	0
18/07/1996	0	0	37	0	0	0
08/07/1996	0	0	28	0	0	0

Diagnosis of DGA results

The fault classification had not changed from 06/02/1998 with the IEC 599 Ratio's giving a Thermal fault of High temperature range >700°C. The other Ratio methods gave a similar fault condition.
The IEEE (c57.104-1991) gave a Condition Code 4 with the operating procedure to plan an outage.
The individual Gas production was far in excess of normal levels as defined in the IEC 60599 and by Morgan-Schaffer.
It was recommended to remove this unit from service immediately as the risk of catastrophic failure was considered to be too great.

Internal Inspection and findings

The internal inspection found overheating and burning on the resistor bank. See Figure 14.
Figure 15 A-shows the actual point of burning on the resistor bank point and 15 B-shows a metal strip that had burnt off the resistor bank.

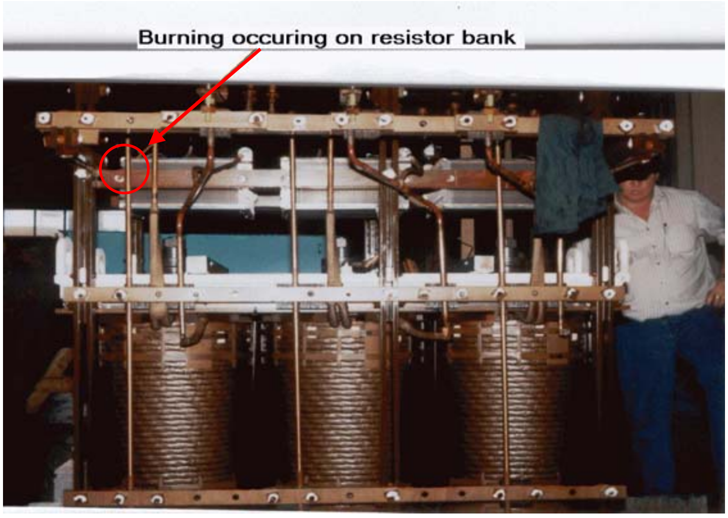
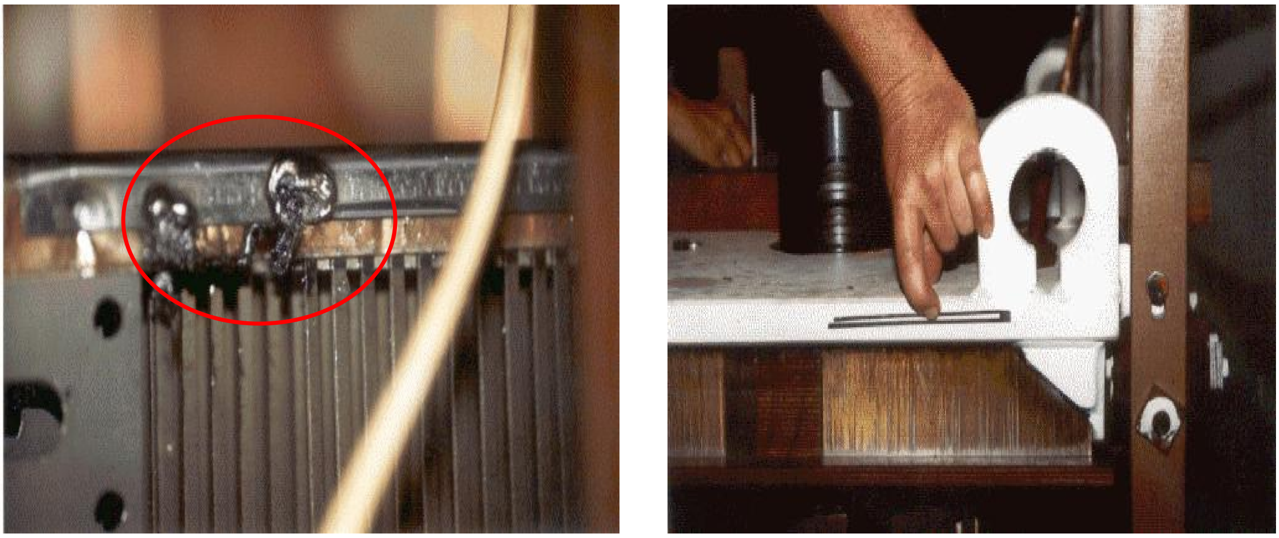


Figure 14-Showing the point on the Resistor bank where the Overheating was occurring.



(A) (B)

Figure-15 A-showing the actual point of burning on the resistor bank point and 15 B-showing a metal strip that had burnt off the resistor bank.

Root cause.

The unit was retuned to service after repairs but the root cause had not been established. The initial theory was that the cross sectional area of the metal strips was insufficient for the magnitude of the current.

BAY 13 Reactor Transformer

On the 05th November 1999, a gas trip was triggered by the Buchholz relay. The urgent DGA on the oil sample confirmed an arcing condition (IEC 599-Discharge of high energy). This transformer also had a gassing pattern showing a thermal fault with the initial indication in February 1998. See Figure 14 giving the Graph trend and with the results listed in Table 18.

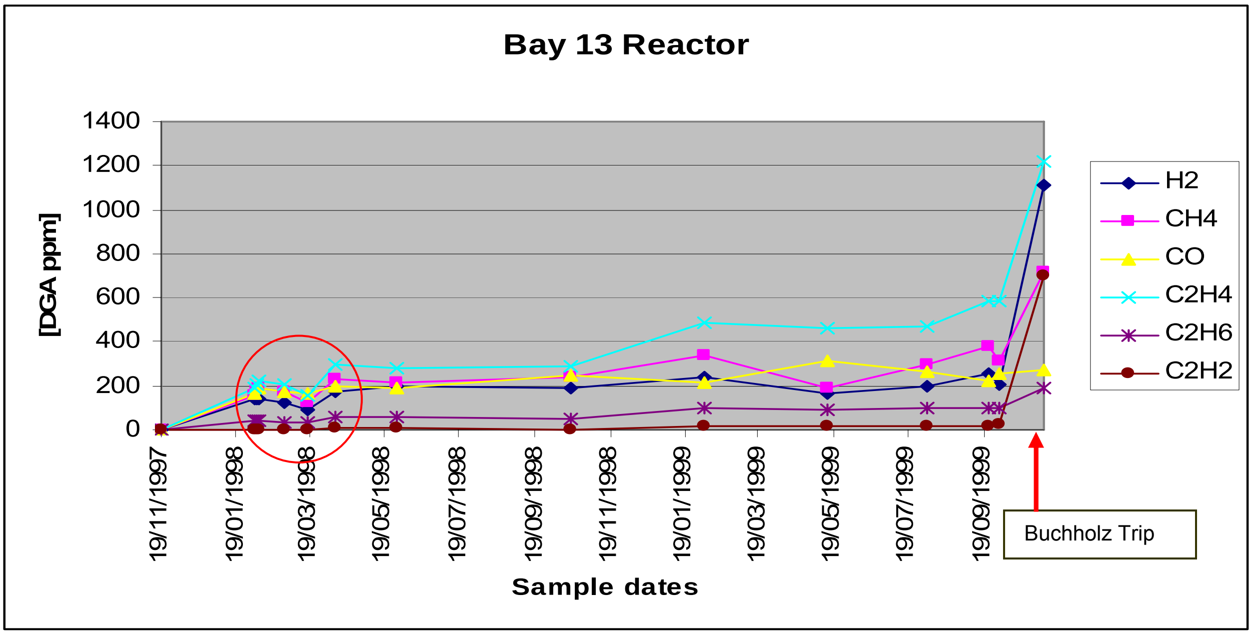


Figure 14 Graph trend

Table 18-DGA from BAY 13 Reactor

Sample Date	H_2	CH_4	CO	C_2H_4	C_2H_6	C_2H_2
05/11/1999	1114	719	270	1217	188	699
30/09/1999	210	311	257	581	97	26
21/09/1999	255	375	222	588	99	18
03/08/1999	197	293	260	467	95	20
13/05/1999	161	187	312	461	88	18
02/02/1999	236	334	213	490	95	18
18/10/1998	192	235	250	285	52	3
29/05/1998	194	216	191	281	58	6
08/04/1998	169	232	197	299	57	6
17/03/1998	137	180	163	156	31	3
27/02/1998	127	170	177	206	33	4
06/02/1998	139	188	187	223	45	4
04/02/1998	140	181	190	210	42	4
02/02/1998	136	160	168	187	38	3
19/11/1997	0	0	0	0	0	0

The transformer was removed to a Works Facility for Inspection and repairs. See Figure 15

Figure 15-Reactor transformer being De-tanked at the Works facility

Internal Inspection and findings

The internal inspection found overheating and burning on the resistor bank and a flash-over had occurred on the bare copper conductor above the resistor bank. See Figure 16.
Figure 17 A-shows the actual point of overheating on the resistor bank point and 17 B-shows the point of flash-over with the carbonisation on the copper conductor.

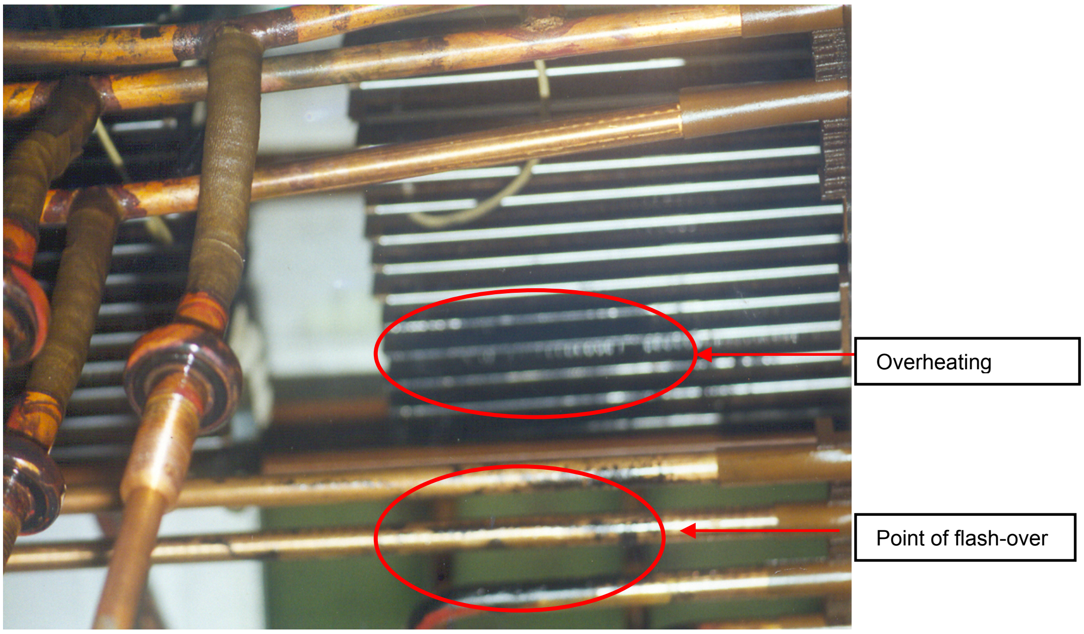
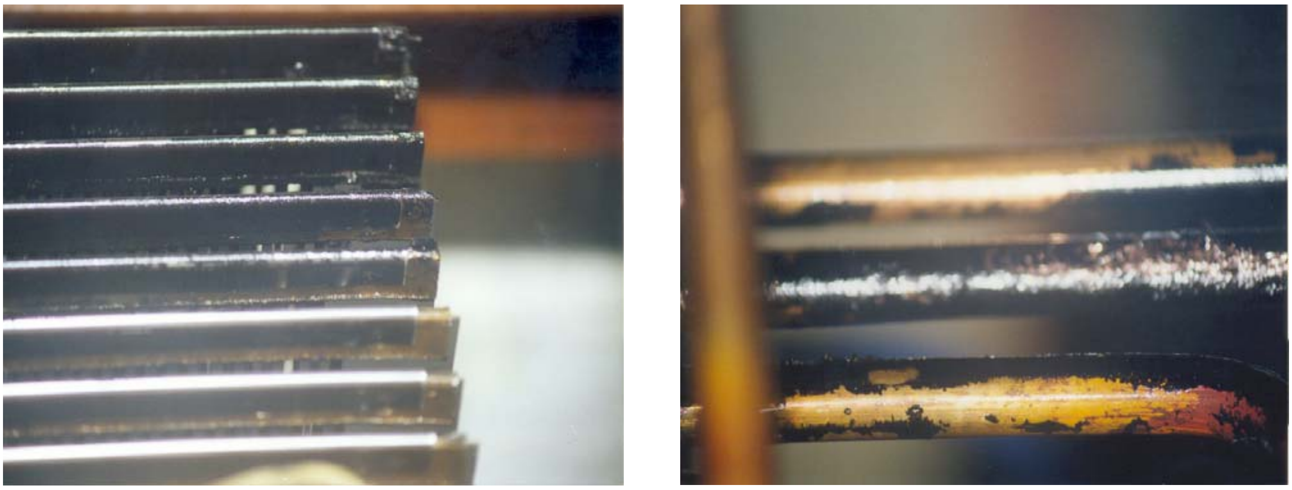


Figure16-Showing the overheating on the resistor bank and the point of flash-over.



(A) (B)

Figure17 A-B Showing the overheating on the resistor bank and the point of flash-over

Mechanism of the flash-over and Root cause.

The overheating on the resistor bank as a result of voltage stress caused gas bubble formation. Gas bubbles have a lower dielectric strength than either oil or the oil-impregnated solid insulation under normal conditions. Bubbles therefore can be a source of partial discharge activity or in this case a discharge of high energy. The voltage stress is inversely proportional to the dielectric constant and therefore gas bubbles are much more stressed than the surrounding oil and solid insulation.

The root cause of the overheating or overstressing of the resistor bank had still not been established. The manufacturer appointed specialist consultants to investigate the problem.

BAY 13 Reactor Transformer

On the 21st January 2001, another gas trip was triggered by the Buchholz relay. The urgent DGA on the oil sample again confirmed an arcing condition (IEC 599-Discharge of high energy). It is interesting to note that the sample taken 24/12/1999 was already indicating a discharge of high energy due to the overstressing of the resistor bank. See Figure 15 giving the Graph trend. The DGA results from the 1st Buchholz trip are listed in Table 19.

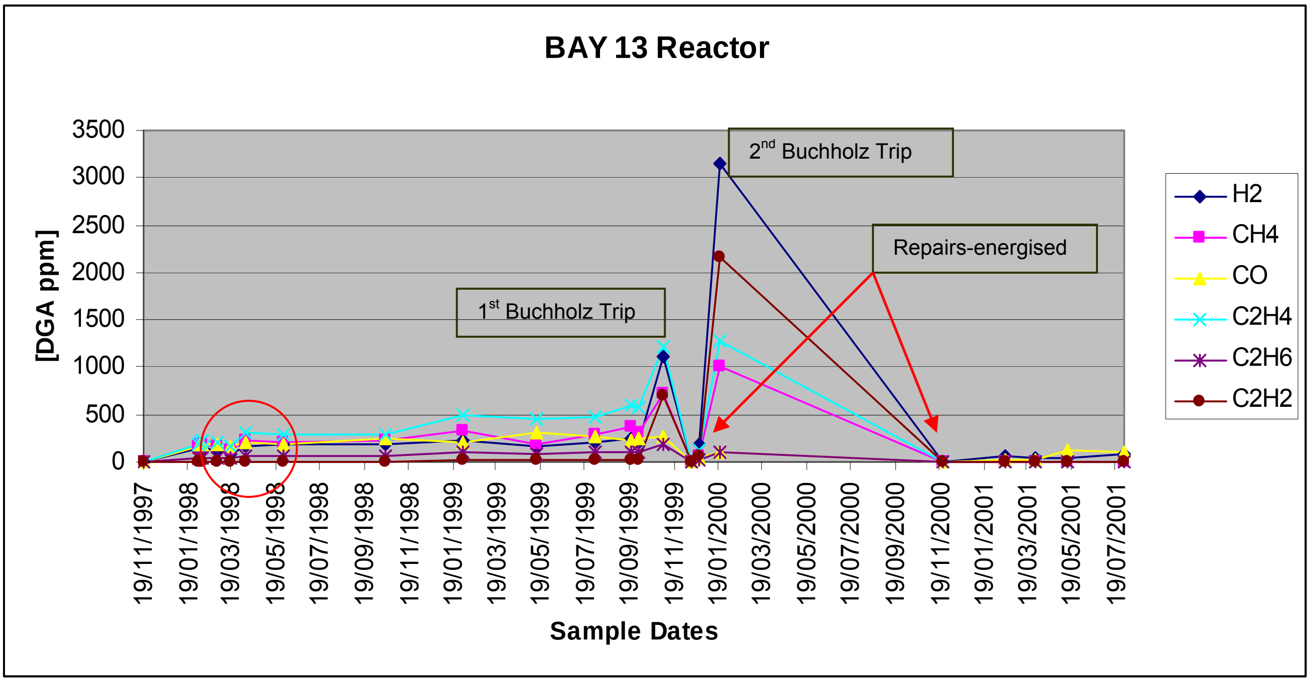


Figure 15-DGA graph trend

Table 19-DGA results following the1st Buchholz trip

Sample Date	H_2	CH_4	CO	C_2H_4	C_2H_6	C_2H_2	Sample Type
30/07/2001	78	5	102	0	10	0	
14/05/2001	45	3	114	0	0	0	
30/03/2001	49	3	16	1	0	0	
16/02/2001	62	0	23	0	0	0	
23/11/2000	0	0	0	0	0	0	Repair/oil purification
21/01/2000	3160	1014	105	1278	112	2170	2nd Buchholz Trip
24/12/1999	191	62	37	123	27	71	
13/12/1999	0	0	0	0	0	0	Repair/oil purification
05/11/1999	1114	719	270	1217	188	699	1st Buchholz Trip

Root cause and the next step.

After extensive studies by the Specialist Electrical consultants the root cause was established as the Fifth Harmonic being amplified within the transformer causing it be subjected to 10 times its rated current for a couple of milli-seconds. Design fault involving the power factor correction. (Weakness in design).

This had significant cost implications. The manufacturer had to change the design of the power factor correction. This also involved removing all the External 22kV Reactor transformers from service.

Partial Discharge in 22 kV Transformers predicted by DGA.

Partial Discharge (PD) activity

A partial discharge is an electrical discharge or spark that bridges a small portion of the insulation between two conducting electrodes.

Partial discharge can occur at any point in the insulation system, where the electric field strength exceeds the breakdown strength of that portion of the insulating material.

Partial discharge can occur in voids within solid insulation, across the surface of insulating material due to contaminants or irregularities, within gas bubbles in liquid insulation or around an electrode in gas (corona activity).

The process of deterioration can propagate and develop, until the insulation is unable to withstand the electrical stress, leading to flashover.

The ultimate failure of HV/MV assets is often sudden and catastrophic, producing major damage and network outages.

Partial Discharge (PD) Detection and Measurement Technologies

There are four main PD techniques that are available.

- Oil sampling to detect dissolved gases (DGA).
- Surveys using UHF interference detection
- Electrical measurement of individual discharges using sensors on the bushing tap, neutral or inserted into the tank.
- The use of probes to locate the PD site

In 1996 a number of Plant Distribution transformers showed severe Partial Discharge (PD) activity detected by DGA in samples taken part of the Condition Monitoring program. The typical nameplate information is as follows in Table 16.

Table 16-Transformer nameplate data

Make: GEC	Year Manufactured: 1994	Primary Voltage: 22 kV
VA Rating: 1600 KVA	Vector Group: Dyn11	Secondary Voltage: 400V
Tap Changer: Off Load	Oil Volume Litres: 1316	Conservator: No

Case Example 1: Significant Partial Discharge activity.

The DGA on this transformer showed abnormal levels of hydrogen and methane and a further sample found significant increases in these gasses. See table 17-DGA results.

Table 17-DGA results

DGA[ppm]	29/11/1996	03/02/1997
Hydrogen H_2	10721	13079
Methane CH_4	729	855
Ethylene C_2H_4	0	14
Ethane C_2H_6	223	239
Acetylene C_2H_2	0	0
Carbon Monoxide CO	285	336
Carbon DioxideCO_2	2609	2562
TCG	11958	14514

Diagnosis of DGA results

Various DGA diagnostic codes are compared for the DGA data on 03/02/1997.
The ratio methods are listed in Figure 16. Key gas and signatures are given in Figure 17 A and B.
Figure 18 gives the Gas production rates. Figure 19 gives the Concentration levels in accordance to CSUS.
The operating procedures are given in the Westinghouse guidelines-Figure 20 and the IEEE (c57.104-1991) in Figure 21.

IEC 599 DIAGNOSIS OF GAS SAMPLE DATA

C_2H_2/C_2H_4	C_2H_4/C_2H_6	CH_4/H_2	$C0_2/C0$
0	0.1	0.1	7.6

Normal C02/C0 Ration (>3 and <11)

Fault: Partial discharges of low energy density

Typical Examples: Discharges in gas-filled cavities resulting from incomplete impregnation, or super-saturation or cavitation or high humidity

ROGERS RATIO DIAGNOSIS

CH_4/H_2	C_2H_6/CH_4	C_2H_4/C_2H_6	C_2H_2/C_2H_4
0.07	0.28	0.06	0

Suggested Diagnosis: Slight Overheating-to 150°c

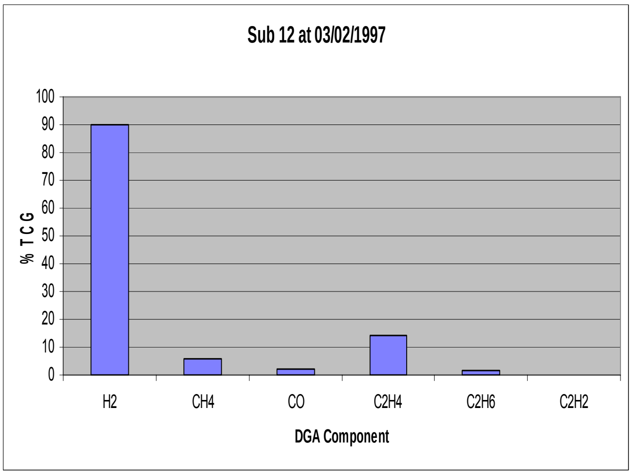
Duval Triangle

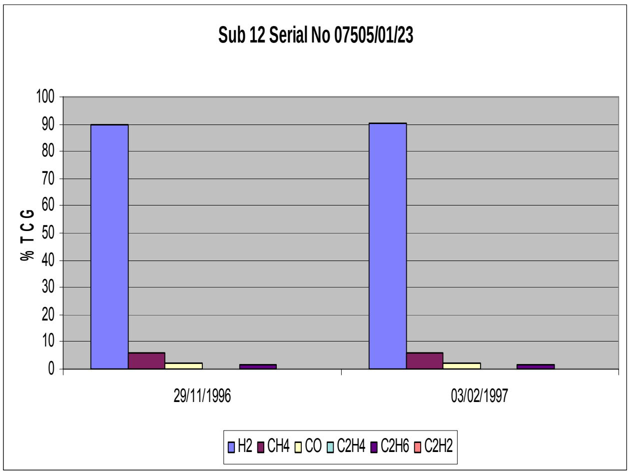
% CH_4	%C_2H_4	%C_2H_2
98	2	0

Symbol: PD-Fault Partial Discharges

Examples: Discharges of the cold plasma (corona) type in gas bubbles or voids, with the possible formation of X-wax in paper.

Figure 16-Ratio methods





(A) (B)

Figure 17 A/B-Key gas method and DGA signatures

GAS PRODUCTION RATES			MORGAN-SHAFFER TABLES	
From 29/11/1996 to 03/02/1997				
Dissolved Gas		ppm/day	Norm	Serious
HYDROGEN	(H2)	**35.72**	0.1	2
METHANE	(CH4)	**1.91**	0.05	6
ETHANE	(C2H6)	**0.23**	0.05	6
ETHYLENE	(C2H4)	**0.21**	0.05	6
ACETYLENE	(C2H2)	0	0.05	1
CARBON MONOXIDE	(CO)	0.77	2	10
CARBON DIOXIDE	(CO2)	-0.71	6	20

Figure 18-Gas production rates

GAS	LIMITS			LEVEL	INTERPRETATION
Normal	Normal	Abnormal			
H2	< 150	> 1000	**Abnormal**	**13079**	**Arcing corona**
CH4	< 25	> 80	**Abnormal**	**855**	**Sparking**
C2H6	< 100	> 350	Elevated	239	
C2H4	< 20	> 100	Normal	14	
C2H2	< 15	> 70	Normal	0	
O2	< 2000	> 35000	Elevated	3923	
CO	< 500	> 1000	Normal	336	

Figure19-CSUS concentration levels

TOTAL COMBUSTABILE GAS LEVEL (Westinghouse guideline)	Recommended Action
Total Combustible Gas(TCG): 14523 ppm	Make weekly analysis to determine gas production rates. Contact manufacturer

Figure 20-Westinghouse Guidelines

TOTAL COMBUSTIBLE GAS PRODUCTION RATES (c57.104-1991)

TOTAL COMBUSTIBLE GAS (TCG)	PRODUCTION RATES ppm/day	OPERATING PROCEDURE
From 29-11-1996 to 03-02-1997	220.0	Condition 4: Consider removal of service

Figure 21-IEEE (c57.104-1991) Condition codes

All the DGA diagnostic methods indicated a problem with the conclusion that the transformer be returned to the manufacturer for inspection and repairs

Internal Inspection and findings

The initial response from the manufacture was that the unit had passed all Electrical testing prior to leaving the factory.
The following electrical tests were performed prior to the Visual inspection.

- Winding insulation Resistance: Satisfactory
- Induced Over voltage at 75%.
- Separate Source at 75%.
- Core Insulation Resistance: measured at 5000 MOhms. After detanking, 5000 MOhms.

Internal Inspection

The following is a list of the findings:
The internal earth strip that links the core with the external core bushing was found to be loose.
See Figure 22 A
Sediments were detected to be deposited over the top frame channel as well as on the bottom of the tank.
Carbon marks were detected over the bottom core-clamp insulation-See Figure 22B.

(A)

(B)

Figures 22 A and B showing the findings

Root cause.
The discharges were produced between adjacent core loops due to inappropriate insulation.

Continuation of Partial Discharge problem

The transformer was repaired by the manufacturer in February 1997; however DGA samples taken after re-energisation showed that the repairs had not been effective. The unit was returned to the manufacturer in August 1999 for further repairs that were effective. See Figure 23 Showing the DGA trend which also acts as a timeline.

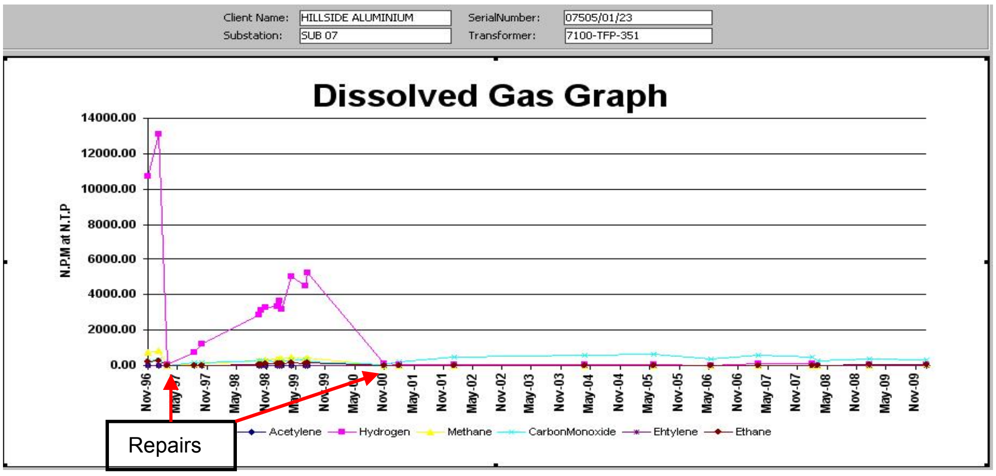


Figure 23 Showing the DGA trend

Case Example 2: Significant Partial Discharge activity.

The DGA on this transformer showed abnormal gas production of hydrogen and methane.
See Table 18 giving the name plate data and Figure 24-shows the DGA trend. Although the actual levels were only in the elevated range according to the CSUS, the production rates and Ratio methods provided enough evidence of serious Partial Discharge activity. The design review was also considered when taking the decision to remove it from service for an internal inspection. Previously four similar transformers had been returned to the manufacturer. In all of the cases DGA had identified the Partial Discharge.

Table 18-Transformer name plate data

Make: GEC-ALSTHOM	Year Manufactured: 2007	Primary Voltage: 22 kV
VA Rating: 2000 KVA	Vector Group: Dyn11	Secondary Voltage: 400V
Tap Changer: Off Load	Oil Volume Litres: 1529	Conservator: Yes

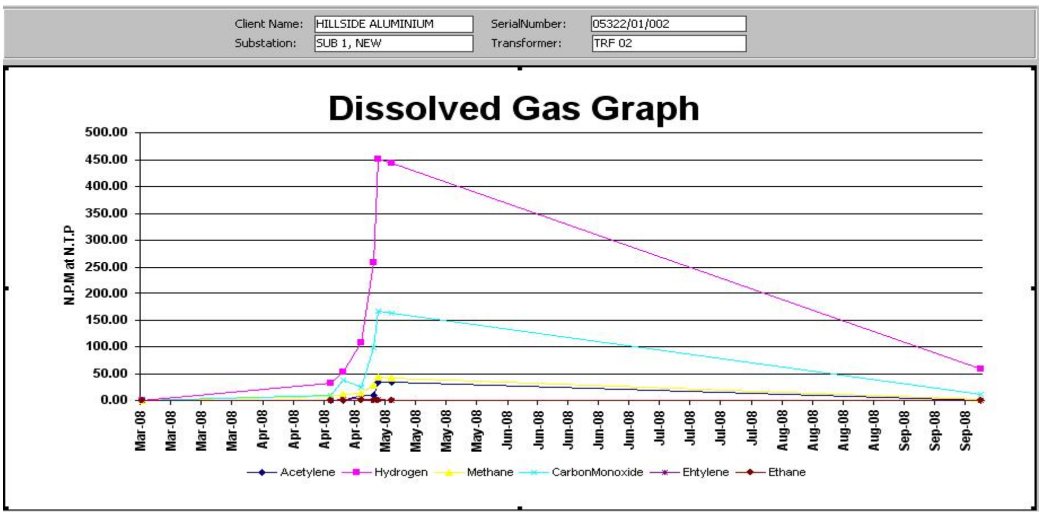


Figure 25-DGA trend

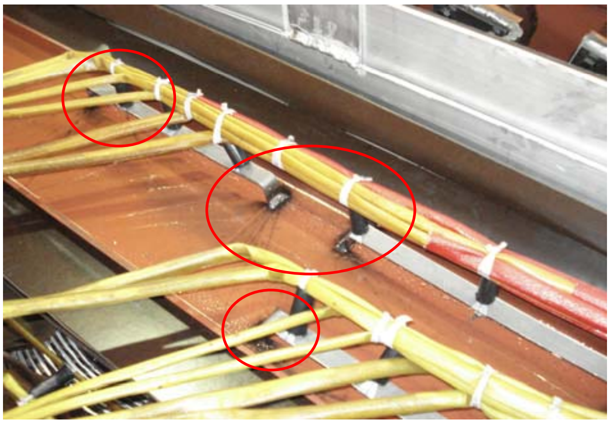
Internal Inspection and findings

Partial discharge-See Figures 25 A: B: C: D showing the activity.

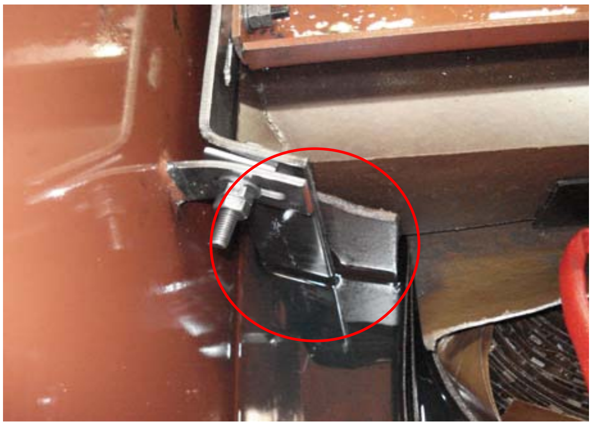
- Partial discharge activity evident between the bottom of the U-frame and bottom of the tank.
- Electrical activity observed on the U-frame fixing brackets and bolting arrangement.
- Partial discharge activity manifests in pitting and carbon deposits.
- Alstom is of the opinion that the partial discharge observed is the root cause of the excessive gas generation.
- The rest of the active part shows no additional signs of tracking or discharge.

Quality issues

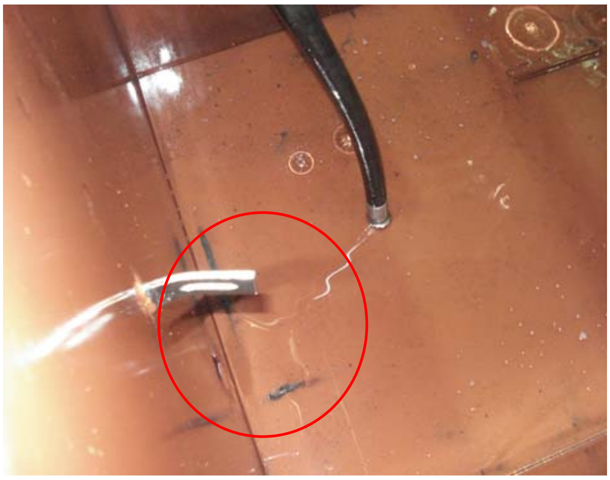
- LV busbar welded connections from winding to bushing showed cracks on at least three areas
- Bushing crack observed on LV c phase
- Bushing damage observed on LV a phase



(A)



(B)



(C)

(D)

See Figures 25 A to D showing the Partial Discharge activity

Root Cause and Savings

The root cause was established to be weakness of design and non-conforming quality control during manufacture.

Savings in the R Million range was achieved by accurately diagnosing the fault type during warranty. The transformers were repaired under warranty.

Thermal Faults detected by DGA.

Case Example 1: Jockey Rectifier Transformer

The DGA on this transformer showed abnormal gas production of hydrogen, methane, ethylene and ethane about 20 months after Energisation. The fault condition was diagnosed as a thermal fault of medium temperature in the range 300°C-700°C. The recommendation was to remove from service for Inspection. See Table 19 giving the name plate data and Figure 25-shows the DGA trend.

Table 19-Transformer name plate data

Make: VTD(VALDAGNOY)	Year Manufactured: 2002	Primary Voltage: 22 kV
VA Rating: 5160 KVA	Vector Group: Dyn11	Secondary Voltage: 120V
Tap Changer: Off Load	Oil Volume Litres: 12644	Conservator: Yes

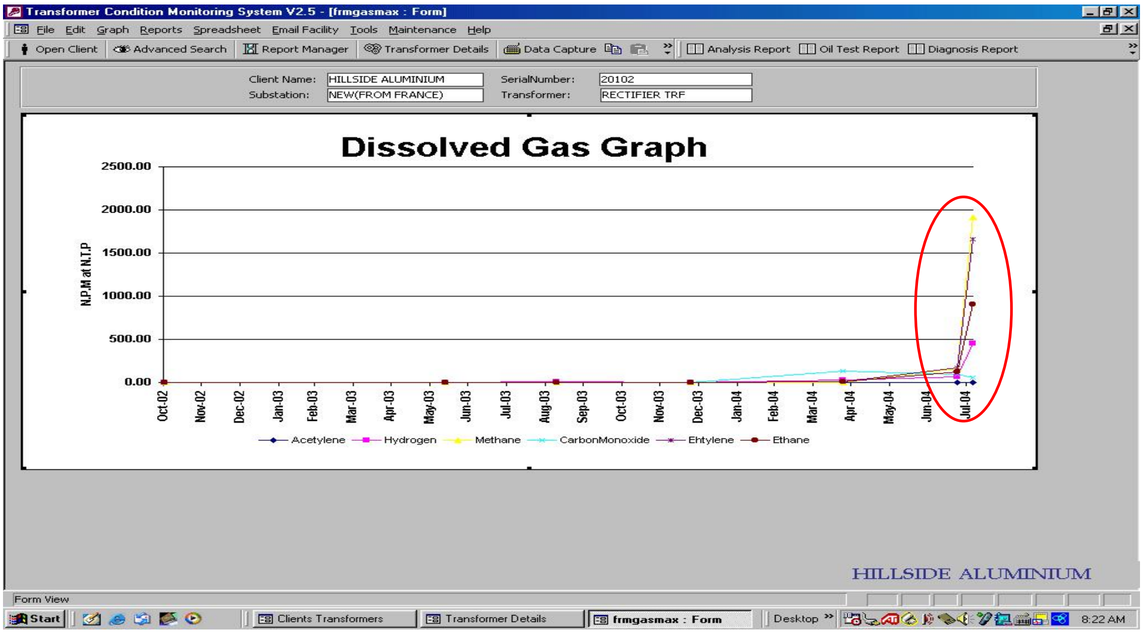


Figure 25-shows the DGA trend

Internal Inspection and findings-See Figures 26 and 27

Further inspection revealed the existence of at least one more closed loop formed by the earthing connections of the other steel parts for the neutral clamping structure.

The overheating occurrence only became evident because the connection presented high resistance for the unintentional circulation current in service.

In addition, the clamping bolts for the six sets of phase windings were also found to have created at least two major loops for circulating currents due to unintended multiple earthing. The clamping bolts and the upper and lower metal frames formed loops into which current was induced.

These loops were the result of obvious mistakes in application of the insulation for the clamping bolts to maintain single point earthing for the frames and metal clamping rings for the windings. Each set of windings has its own metal clamping frames and clamping rods. It was evident that similar situations were created for circulating currents on both the upper and lower sets of windings.

At least one insulation washer between a bolt and an upper frame exhibited signs of overheating by the flow of circulating currents.

The earthing via the clamping bolts was obviously intended to earth the split metal winding clamping rings without creating loops between the upper and lower frames. This was however not achieved in practice.

One clamping bolt was identified as having incorrect insulation washers. That is, insulation on the one side of the hole through the frame but none on the other side.

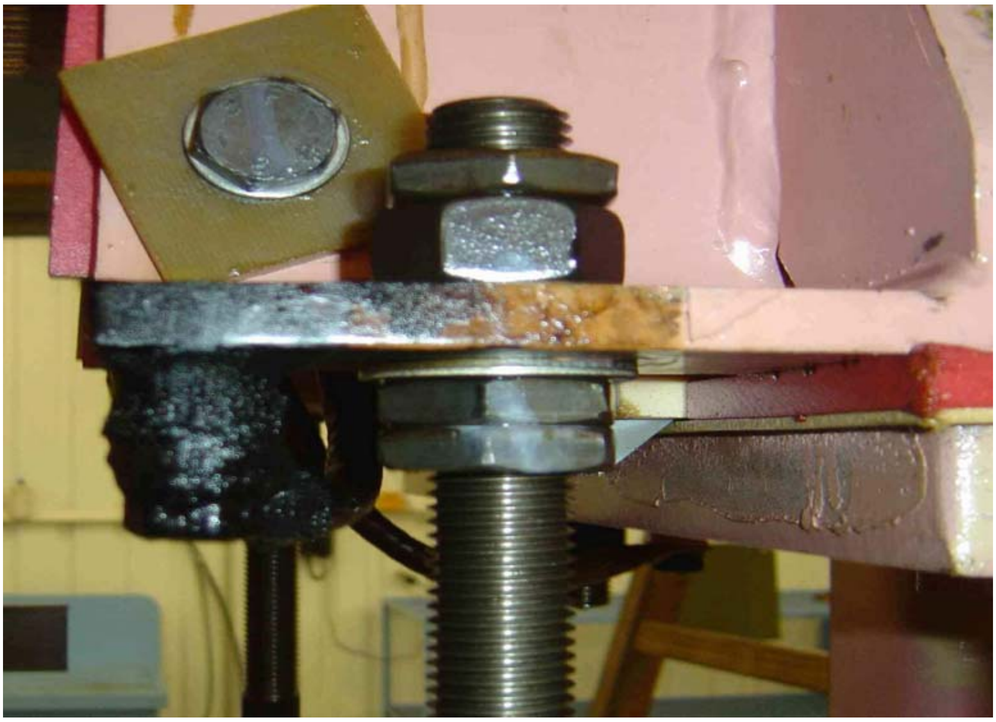


Figure 26-Termination for potential connection became a hot spot due to circulating current

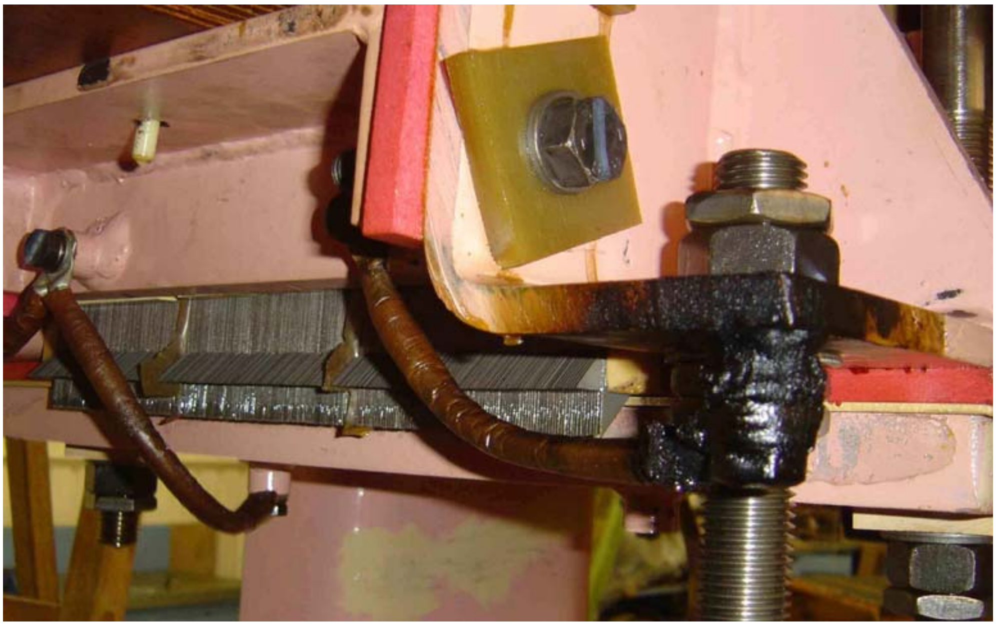


Figure 27-Second view of hot spot - bad connection for circulating current.

Conclusion

The transformer was repaired at a works facility under the warranty of the OEM.

Case Example 2: 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-700°C. The recommendation at 30/09/1996 was to remove the unit from service for Inspection.
See Table 19 giving the name plate data and Figure 25-shows the DGA trend.

Table 19-Transformer name plate data

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

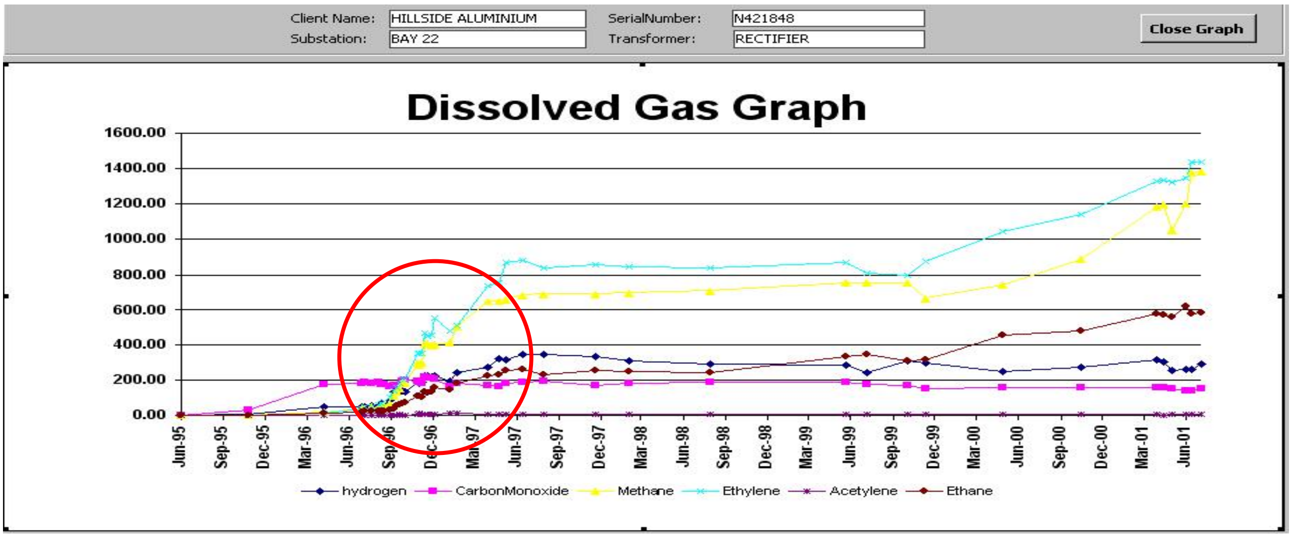


Figure 25-DGA trend up to July 2001

The manufacturers 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. See Figure 25.

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. See Figure 27.

However, after the oil de-gassing in July 2001, the same phenomenon of exponential gas production followed by a leveling off was seen. See Figure 27. 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.

Condition Monitoring and failure event: Bay 22 Rectifier

This transformer was ranked as having the highest risk of failure, based on the DGA-Total Combustible Gas profile-See Figure 26 showing all Rectifier transformers at July 2001.
The condition was monitored by regular oil samples. On-line DGA was considered.
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 27 showing the DGA trend.

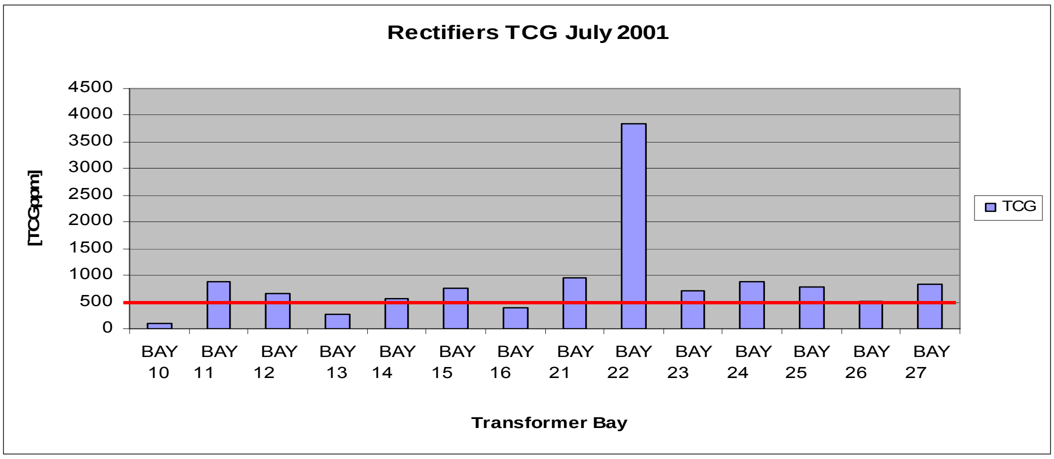


Figure 26-TCG profile for Bay 1 & 2 Rectifiers

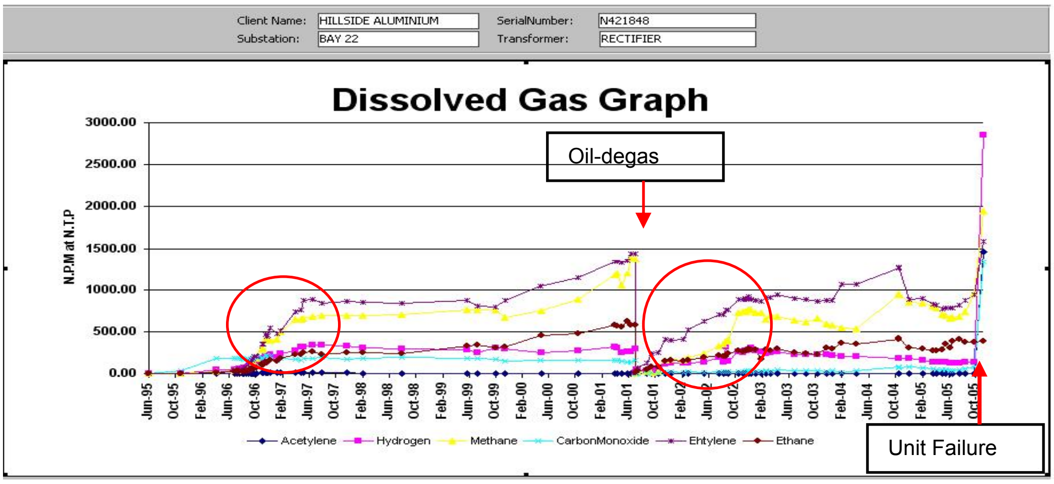


Figure 27-DGA-Profile

Failure Event

When T22 transformer failure developed on 18 November, 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 d.c. busbar system.

- The d.c. 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 (1000V 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 125V d.c. supply is common between Potline 1 and 2.

- The elevated voltage on the potline d.c. bus resulted in the insulation level of the Potmicros being exceeded, damaging a number.

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 minutes 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. Figure 28 shows the transformer being de-tanked at the works facility as part of the failure investigation

Figure 28-Transformer De-tanking

Internal Inspection and findings

'A' Phase High Voltage winding open circuit and flashed to core. See Figure 29 A

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. See Figure 29B


(A) (B)

Figures 29 A and B-Show the damage

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. See Figure 30A.
Overheating of the Core. See Figure 30 B.


(A) (B)

Figures 30 A and B show 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); and
(ii) Circulating currents in the core, frame and tank.
(b) Defective bolted or welded joints on current carrying parts.

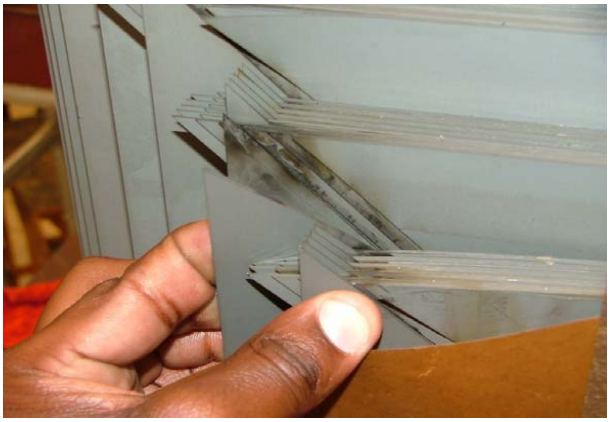
The Sweep Frequency Response Analysis revealed significant problems with the HV winding.

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 Figures 31 A and B.
- 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


(A)


(B)

Figures 31 A and B show the Core overheating. A is T21 and B is T 22

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 enable, 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 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 identify the faults at early life.

DGA oil testing is typically a critical first step in any power transformer analysis.

The D.G.A. technique detects newly formed faults both accurately and consistently, and will locate a fault that cannot be detected in any other way.

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"

C.E.G.B (1974) reports over 90 % of transformers faults are detected by D.G.A. The estimated savings was between 1.5-3.0 million pounds per annum. Confidence in the method is now such that transformers are sent to works for repair and replaced by spares on no evidence other than that of D.G.A.

CIGRE REPORT 1984 states that "Dissolved-gas-in oil chromatographic is successfully applied to fault detection in the maintenance of large power transformers. Savings achieved are in the 100 MILLION $ range.

Independent Professionals and Consultants are only able to offer their opinions.

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

References

1. Guide to Transformer Maintenance (1st, 2nd ,3 rd edition)

2. IEC Publication 60599, “Mineral Oil-Impregnated Equipment in Service – Guide to the Interpretation of Dissolved and Free Gases Analysis”, March 1999.

3. EEE Std C57.104-1991, “Guide for the Interpretation of Gases Generated in Oil- Immersed Transformers”, 1991.

4. M.Duval, “A Review of Faults Detectable by Gas-in-Oil Analysis in Transformers”, IEEE Electrical Insulation Magazine, Vol.18, No.3, p.8 (2002).

5. M.Duval and A.dePablo, “Interpretation of Gas-in-Oil Analyses Using New IEC Publication 60599 and IEC TC10 Databases”, IEEE Electrical Insulation Magazine, Vol.17, No.2, p.31 (2001).

6. M.Duval, P.Gervais and G.Belanger, « Update on Hydro-Quebec’s Experience in the Interpretation of Dissolved Gas Analysis in HV Transformers », CIGRE Symposium
7. 1993, Berlin, Paper # 110-14 (1993).

8. John A. Lapworth National Grid (UK) A SCORING SYSTEM FOR INTEGRATING DISSOLVED GAS ANALYSIS RESULTS INTO A LIFE MANAGEMENT PROCESS FOR POWER TRANSFORMERS

9. M.Duval, "Fault gases formed in oil-filled breathing EHV power transformers- The interpretation of gas analysis data", IEEE PAS Conf.Paper No C 74 476-8, 1974.

10. S.Lindgren, "Power Transformer Asset Management On-Line DGA- The New Ballgame", EPRI Substation Equipment Diagnostics Conference XI, New Orleans, Louisiana (Feb.2003).

11. CIGRE Task Force TF15/12-01-11 (M.Duval, Convenor), Final Report to be published as a CIGRE Brochure and in Electra in June 2006.

12. CIGRE Working Group 12.18, "Life Management of Power Transformers " Final Report (to be issued).

13. Halstead, W. D., "A Theoretical Assessment of theFormation of Gaseous Hydrocarbons in Faulty Transformers", J. Inst. Petroleum 59, pp 239-241, September 1973.

14. Rogers, R. R., "IEEE and IEC Codes to Interpret Incipient Faults in Transformers, Using Gas in Oil Analysis", IEEE Trans. Electr. Insul., Vol EI-13 No 5, October 1978

15. IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers, IEEE Std C57.104-1991

16. McGrail A. J. et. al., "Data Mining Techniques to Assess the Condition of High Voltage Electrical Plant", Working Group 15.11 Paper for 2002 CIGRE Session, August 2002.

17. Esp D.G. and McGrail A.J., "Advances in Data Mining for Dissolved Gas Analysis", ISEI 2000 Conference, Anaheim , California, 2000.

18. J. A. Lapworth and T. McGrail, "Transformer failure modes and planned replacement", The IEE Colloquium on Transformer Life Management, 22 October 1998.

19. H. Ding and S.Ryder, "When to Replace Aged Transformers? Experiences from Forensic Tear Downs and Research", Euro TechCon 2008, Liverpool, November 2008.

20. W.H. Bartley, "Life Cycle Management of Utility Transformer Assets", Breakthrough Asset Management for the Restructured Power Industry, October 10–11 2002, Salt Lake City, Utah.

21. G. Sanchis, E. Rijks and G. Ford, "Asset Management and the End-of-Life Issue", 6th Cigré Southern African Regional Conference, Somerset West, South Africa, 17 – 21 August 2009.

22. Gary A. Heuston, Paul J. Griffin, Anthony J. McGrail, Ph.D, Richard K. Ladroga, P.E., Doble Engineering Company" ADVANCED DIAGNOSTICS SUPPORT CRITICAL DECISION MAKING

23. R. Heywood, J. Lapworth, L. Hall, and Z. Richardson, "Transformer lifetime performance: Managing the risks", 3rd IEE International Conference on Reliability of Transmission and Distribution Networks, London; February 2005.

24. R. Heywood and A. Wilson, "Managing reliability risks-Ongoing use of ageing system power transformers", Doble Israel Conference 2007.

25. H. Ding and S. Ryder, "When to replace aged transformers? Experiences from forensic tear downs and research", Euro TechCon 2008. Liverpool, 18-20 November 2008.

26. CIGRÉ Working Group 12.18, "Guide for life management techniques for power transformers", CIGRÉ Brochure No. 227, 20 January 2003.

27. CIGRE WG 12.18 "Life management of transformers, draft interim report", July 1999.