TRANSFORMER CONDITION ASSESSMENT AND RECENT FAILURES

by
Roger Cormack, Eskom Transmission Technology
and
Luwendran Moodley, Doble Engineering Africa

INTRODUCTION

Eskom Transmission is responsible for the performance and life management of about 500 transformers and 105 reactors in almost 150 substations operating from 132 kV to 765 kV. Most of these transformers are in the range of 35 to 25 years. Due to the aging fleet Eskom Transmission is currently on a drive to perform condition assessment on all transmission transformers. A number of different techniques were investigated and implemented for condition assessment. The fundamental principles behind these techniques were to establish a ranking system that can provide a realistic risk of failure.

CRITERIA AND TOOLS FOR END OF LIFE DECISION

At a given time (possibly after a fault) the question arises whether or not a transformer will meet the requirements of performance, reliability and maintainability. How does the utility decide whether to replace the transformer? This is not a simple task as a number of factors must be considered. The minimum assessment criteria considered must include:

- Safety
- Age
- Manufacturer
- Design
- Condition
- Strategic importance
- Inadequate ratings
- Environmental
- Economics
- Maintainability
- Loading history
- Failure history

The safety risk assessment associated with continued operation that will compromise the fundamental safety of staff, other plant and the public.

The treatment of transformers by age is a matter of owner's internal policy. The age of a transformer can have a number of factors including the effect on the mechanical strength of the transformer's insulation and hence it's ability to withstand common short circuit forces that are inherent in a transmission system. The relationship between the age of the transformer and it's performance is a subject of great uncertainty. However, coupled with the other factors listed here the transformer's age can play an importance role in risk decision.

The place of manufacture and the manufacturer is a key indicator of quality related issues. Eskom has in place an intensive criterion to evaluate manufacturers all over the world.

It is common knowledge that transformers built and designed in the past have proven to be highly reliable with a low failure rate for many decades. The introduction of advanced computer programming for design purposes have resulted in modern transformers having a low loading capability. However, it is noticed that older transformers may lack adequate provision for leakage flux and have a higher probability of localized thermal problems. Further, industry standards were revised to ensure greater short circuit duty for modern transformers.
The identification of dominating deterioration and failure modes for each design group can then be used to identify the optimum diagnostic strategy to reveal the onset of failure modes.

Strategic importance or criticality of the transformer in terms of security of the system is of paramount importance and should never be compromised. What is it feeding? Is always the question.

With the ever increasing growth of the network the transformer rating may be inadequate. A further and more important consideration is the short circuit rating of the transformer. As discussed older transformers did not have to pass the present stringent short circuit duty called for in most specifications.

Environmental threat due to oil leaks, oil contamination and excessive noise leading to complaints from members of the public is a reality that must be considered.

The economic analysis associated with the maintenance, refurbishment or replacement decisions can best be done on a life cycle cost (LCC). The traditional approach to LCC treats further costs as being fixed and the net present value (NPV) is calculated on this basis. However, further costs are uncertain and should more appropriately be treated as variables belonging to a probability distribution and the NPV is then calculated using the Monte Carlo approach. On this basis, the timing and cost of failure, planned and corrective maintenance and disposal costs are represented as probability distributions. The cost of refurbishment or replacement is set for particular times in each study. Note that once refurbishment or replacement takes place, variables such as failure rate are adjusted to a new disposition of the transformer.

Maintainability is based on spare parts (bushing, tapchanger parts) availability, appropriately skilled and experienced personal and original equipment manufacturer support. The recent status in South Africa with the lack of skill is a grim reality that must be considered. A further consideration is gaining access to transformers particularly at higher voltages. To maintain them is an increasingly significant constraint that is exacerbated by the country’s energy crisis.

The loading history of the transformer is important to note and the periods of overloading should be compared to original loading design philosophy. Extensive periods of overloading will result in higher operating temperatures that will cause the premature degradation of insulation. This problem is exacerbated by high ambient temperatures or cooling system problem or blocked oil ducts.

Transformer failure history is an excellent source for identifying generic trends in transformers of similar designs; identify reoccurring faults, indicator for increasing or deceasing maintenance frequency etc. The analysis of failure history can also be an excellent source of information even for small population of transformers which is supplemented by industry data.

The condition of the transformer takes into consideration all electrical and chemical tests performed on the transformer. However, the condition is not limited to the above as internal and an external visual inspection has a great impact on the condition of the transformer.

The aim of this process is to rank the transformer in terms of it’s overall performance.

In terms of this paper only the transformer condition will be used for ranking a fleet of transformers.

TRANSFORMER CONDITION ASSESSMENT

What we know about transformers is that their life expectancy can vary from a few cycles (ms) to more than fifty years. This fact is interesting but not very useful to an engineer responsible for a given network.
What we need to know is the life expectancy of a particular transformer in a given network. This fact is interesting and very useful. This is the essences of condition assessment.
Effective condition assessment is not just testing a transformer and reproducing the test results nor is it diagnosing the cause of a failure after the transformer has failed. Cigre Working Group on Life Management Techniques for Power Transformers has defined condition assessment as *“A comprehensive assessment of the condition of a transformer taking into account all relevant information eg. Design information, service history, operational problems, and results of condition monitoring and other chemical and electrical tests”*.

PROPOSED CONDITION ASSESSMENT PROCESS

The condition assessment techniques followed was a two phase approach. The first phase was performed on a sample group of transformers. The second phase was performed on a small sample group when compared to the first phase. Both phases include proprietary risk scoring system and combine analysis of individual units and FMMAA analysis (family /make/ model/ application/ age) of similar designs with similar operating conditions and age.

Phase One

The first phase is online approaches where the transformer is not removed from service for additional testing. Phase one of assessment is a “scanning” approach and is more appropriate as a low cost assessment and step to provide “initial” risk assessment and ranking of transformers in a network. The first phase is essentially a review of available information. These include as much as possible of the following:

Step 1: Basic nameplate information from transformer and tapchanger.
All information related to the transformer’s manufacturer, vintage, serial number design, ratings, BIL, fault level, impedance, cooling system etc must be captured. From this information design related issues with transformers, service advisories from manufacturers, reports of failure on similar designs, pattern of failure on similar designs can be identified.

Step 2: External visual inspection.
A visual inspection is conducted on the following:

- Plinth – check for cracks or deterioration, anchor bolts missing or rusty, evidence of oil leaks, ground leads or connectors oxidized/tight etc.
- Tank - Paint peeling and rust, signs of internal deformation or overheating, oil leaks, loose or missing nuts, bolts, or washers, record liquid level in main tank or any conservator tank, inspect liquid level gauges and wiring, inspect pressure relay and pressure relief device and wiring etc
- Cooling system - Paint peeling and rust, oil leaks, inspect pumps and wiring, inspect fans and wiring, inspect radiators for cleanliness, etc
- Temperature reading - Record temperatures, record position of maximum pointers, inspect temperature sensors and wiring, etc
- Marshalling kiosk - Inspect external for paint peeling and rust, inspect interior for water ingress and rust, heater operating, inspect breakers, contactors, terminals, wiring, etc
- Tapchanger - Paint peeling and rust, signs of internal deformation or overheating, oil leaks, loose or missing nuts, bolts, or washers, record liquid level inspect pressure relay and pressure relief device and wiring, record number of operations, inspect tap changer mechanism, etc
- Bushing - Chipped or broken sheds, oil leaks, oil levels, Inspect connections, etc
- Surge Arrester - Chipped or broken sheds, inspect connections, etc

Step 3: Review of all available documentation

- Factory test report - Used to compare with current test results and operating ability
- Purchasing specification - Used to compare to current manufacturing standards
- Tests results (electrical and oil) - Current data can be compared to Doble database for industry norms
- Failure reports - Indicates the rate of aging, availability and performance
- Maintenance practices - What are you doing?
- Major modifications or rebuild - Indicates the rate of aging generally expected
- Substation fault level - Changes in fault rating
- Loading - Used to calculate loss of life

Step 4: Additional non invasive tests

(i) Oil tests (main tank)

A sample would be taken and analyzed with the standard methods. The table below gives a few standard oil tests.

Dissolved Gas (DGA)	Detection of incepted faults – IEEE, IEC etc
Furfuraldehyde (FFA)	Paper insulation degradation – Chendong relation to DP
Moisture in oil	Insulation dryness
Breakdown Voltage	Dielectric integrity
Acidity	Ageing and sludge
Interfacial Tension	Ageing, sludge and contamination

(ii) Doble DGA Scoring System

Doble has developed an algorithm to mimic the key gas response and gives a single number to track the change in pattern. This method uses the key gas method to present DGA used by IEEE method. The relative proportions of the combustible gases CO, H2, CH4, C2H4, C2H6 and C2H2 are displayed as a bar chart to illustrate the gas signature. The novel aspect of the approach proposed here is that this method is used to investigate and illustrate the clear difference that exists between 'normal' and 'abnormal' results. By contrast, in the IEEE Guide four examples of faults are given, but there is no guidance on what a normal result would look like. The DGA score reflects the seriousness of the signature. DGA results for normal 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.

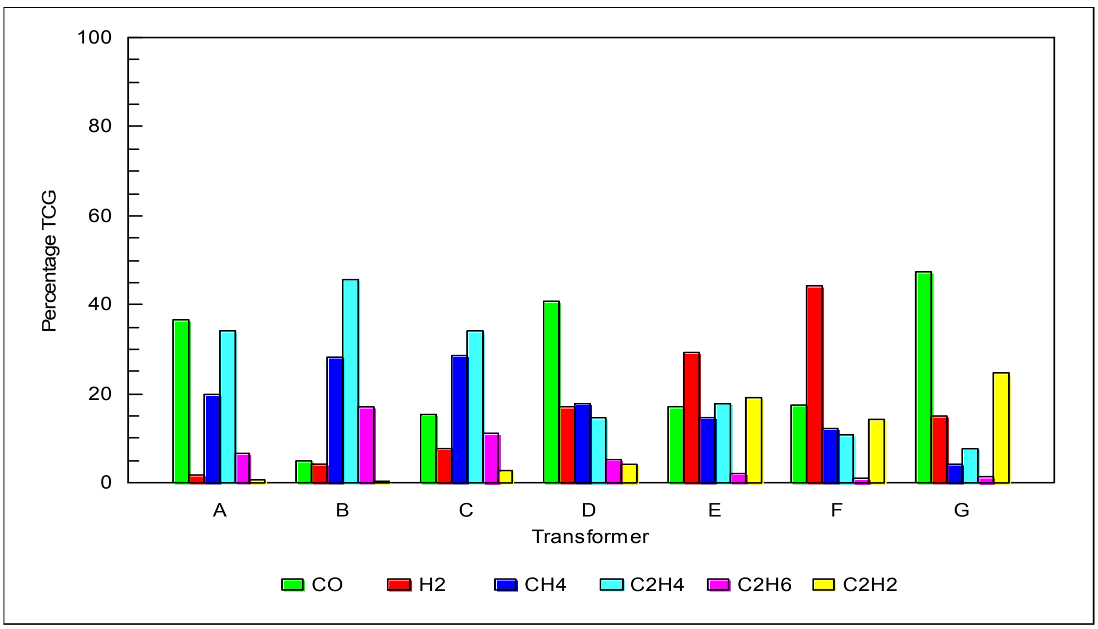

Figure 1: DGA signatures for faulty transformers

A – Core bolt fault
B – Core and frame to earth circulating currents
C – Winding inter-stand fault
D – Winding shorted turns
E – Winding phase to earth fault
F – Winding tracking fault
G – Winding clamping bolt sparking fault

(iii) Infra Red Scan

Infra-red will indicate external joint issues, bushing tap problems, oil levels in bushings and radiators, blockages in radiators, fan function- it can also indicate tank heating from stray flux, or frame tank circulating current.

Assessment of Technical Condition

Once all the information has been gathered and the additional non invasive tests performed the transformers can then be scored based on its condition. The Doble scoring system is given below.

Condition	Definition	Score
New	No damage	1
Normal ageing	Reasonable for age	3
Aged	Some ageing – in need of some monitoring	10
Suspect	Identified ageing, significant risk for failure	30
Unacceptable	Unacceptable ageing	100

Transformers condition is further divided in design, dielectric and thermal and scored to a Doble scoring system. A typical assessment of the technical condition is given below.

Substation	Circuit	Serial No	Manufacturer	Year of Manufacture	Years in Service	Ratio	Rating	Condition	Plan	Overall	Thermal	Dielectric	Comments
Riversider	T5	157471	Ferranti	1967	40	33/11	30	Unacceptable Aging	Replace	106	3	100	High Furans
Riversider	T6	157472	Ferranti	1967	40	33/11	30	Unacceptable Aging	Replace	106	3	100	High Furans
Northdale	T1	K192/2	GEC	1981	26	132/11	30	Unacceptable Aging	Replace	106	3	100	High Furans
Northdale	T2	K192/1	GEC	1981	26	132/11	30	Unacceptable Aging	Replace	106	3	100	High Furans
Woodburn	T1	27123	ASEA	1977	30	33/11	30	Fault	Immediate Intervention	133	3	100	DGA shows signs of dielectric fault
Woodburn	T2	27125	ASEA	1977	30	33/11	30	Fault	Immediate Intervention	133	3	100	DGA shows signs of dielectric fault
Retief Street	T1B	F093/2	GEC	1978	29	132/33	45	Unacceptable Aging	Replace	106	3	100	High Furan
Retief Street	T2A	F093/1	GEC	1979	28	132/33	45	Unacceptable Aging	Replace	106	3	100	High Furan
Mkondeni	T1	28822	ABB	1987	20	132/33	30	Fault	Intervention	36	30	3	Change in resistance which indicates problems with poor joints or poor contacts
Mkondeni	T2	28823	ABB	1987	20	133/33	30	Fault	Intervention	36	30	3	Change in resistance which indicates problems with poor joints or poor contacts
Retief Street	TA	27401	ASEA	1978	29	33/11	30	Fault	Monitor	76	3	3	
Retief Street	TB	27402	ASEA	1978	29	33/11	30	Normal aging	None	9	3	3	
Archbell	T1	2340/1	GEC	1974	33	33/11	30	Developing fault	Monitor	36	30	3	Oil results show starting signs of a localised thermal fault
Crossway	T1	28814	ASEA	1987	20	33/11	15	Developing fault	Monitor	16	3	10	Abnormoral operating temperature with a possiblity of a dielectric/tracking fault
Crossway	T2	28815	ASEA	1987	20	33/11	15	Normal aging	None	9	3	3	

Figure 2: Phase One Assessment

All units have been assessed in terms of design groups with problems, overall condition, thermal and dielectric condition. Each aspect has its own score - a number between 1 and 100. Even with summation any aspect with a 100 score will be carried through and easily recognized. The results are assessed using this sum of the numerical scoring system and it is this sum that determines the position in the “league table” and summarized using a red- green colour traffic light code. It should be emphasized that the score is not permanent it’s a “live” document, reviewed each month as new evidence is presented.

Outcomes of Phase One

Once this process is completed the following is made evident:

- Establishment of an asset register
- Design weakness
- High risk transformers in terms of the dielectric and thermal condition
- High risk transformers in terms of the environment, staff and third parties

All the transformers that fall in the above category would then be considered for phase two of the condition assessment process.

Phase Two

This phase is applied only to units that have been identified as high risk from Phase One.

The Phase Two process is shown in Figure 3. This phase is a comprehensive analysis of the transformer and requires off line testing. The standard off line tests are as follows:

- Tan δ and Capacitance - windings and bushings
- Sweep Frequency Response Analysis
- Leakage reactance
- Insulation Resistance
- Winding resistance
- Exciting current
- Ratio test

Rescoring the Technical Condition

Once all the off line tests are performed the technical condition of each transformer can be rescored with greater detail.

The rescoring now includes the mechanical condition of the transformer. With the final scoring for the condition of the transformer now in place a weighting for each unit level can be assigned. From this a risk of each unit level can be determined. A total risk of each transformer can then be calculated.

Outcomes of Phase Two

Once the rescoring has been completed the following is made evident:

- High risk transformers in terms of the dielectric, thermal and mechanical condition.
- More accurate overall condition as a result of the off line tests
- An action plan in terms of units that require replacement, repair and monitor
- The transformers risk

The results of phase two are merely added to the existing assessment. A typical layout is shown below.

Substation	Circuit	Serial No	Manufacturer	Year of Manufacture	Years in Service	Ratio	Rating	Condition	Plan	Overall	Thermal	Dielectric	Mechanical	Comments
Riversider	T5	157471	Ferranti	1967	40	33/11	30	Unacceptable Aging	Replace	106	3	100	3	High Furans
Riversider	T6	157472	Ferranti	1967	40	33/11	30	Unacceptable Aging	Replace	106	3	100	3	High Furans
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Woodburn	T1	27123	ASEA	1977	30	33/11	30	Fault	Immediate Intervention	133	3	100	30	DGA shows signs of dielectric fault, SFRA movement on HV winding
Woodburn	T2	27125	ASEA	1977	30	33/11	30	Fault	Immediate Intervention	133	3	100	30	DGA shows signs of dielectric fault, SFRA movement on HV winding
Retief Street	T1B	F093/2	GEC	1978	29	132/33	45	Unacceptable Aging	Replace	106	3	100	3	High Furan
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Mkondeni	T1	28822	ABB	1987	20	132/33	30	Fault	Intervention	36	30	3	3	Change in resistance which indicates problems with poor joints or poor contacts
Mkondeni	T2	28823	ABB	1987	20	133/33	30	Fault	Intervention	36	30	3	3	Change in resistance which indicates problems with poor joints or poor contacts
Retief Street	TA	27401	ASEA	1978	29	33/11	30	Fault	Monitor	76	3	3	70	SFRA shows movement on HV windings
Retief Street	TB	27402	ASEA	1978	29	33/11	30	Normal aging	None	9	3	3	3	
Archbell	T1	2340/1	GEC	1974	33	33/11	30	Developing fault	Monitor	36	30	3	3	Oil results show starting signs of a localised thermal fault
Crossway	T1	28814	ASEA	1987	20	33/11	15	Developing fault	Monitor	16	3	10	3	Abnormoral operating temperature with a possiblity of a dielectric/tracking fault
Crossway	T2	28815	ASEA	1987	20	33/11	15	Normal aging	None	9	3	3	3	

Figure 3: Phase Two Assessment

A WORKING MODEL

The above transformer condition assessment technique was applied to a sample population of Eskom transmission transformers. Transformers were selected from a single substation with similar designs and performance. The approach differed from the above technique in that both phase one and phase two were implemented together. This was to test the impact of the model in terms of overall performance of the transformers.

The following was performed on each of the transformers:

- Oil quality
- DGA
- Furans
- Sweep Frequency Response Analysis (SFRA)
- Winding Insulation
- Bushing Insulation
- Exciting Currents
- Ratio
- Leakage Reactance
- DC winding resistance
- Insulation resistance

The electrical and oil tests were analysed to give an overall assessment of the transformers in terms of the dielectric, thermal and mechanical condition of the transformers. The table below indicates the tests that influence the outcome of the transformers condition.

Condition	Test
Dielectric	DGA Furans Winding Insulation (Power Factor) Ratio Insulation resistance
Thermal	DGA Exciting currents DC winding resistance IR scanning
Mechanical	SFRA Impedance Capacitance

The figure on the next page is the final outcome of the condition assessment work. The table ranks the transformers in the dielectric, thermal and mechanical condition to give an overall performance of the transformer.

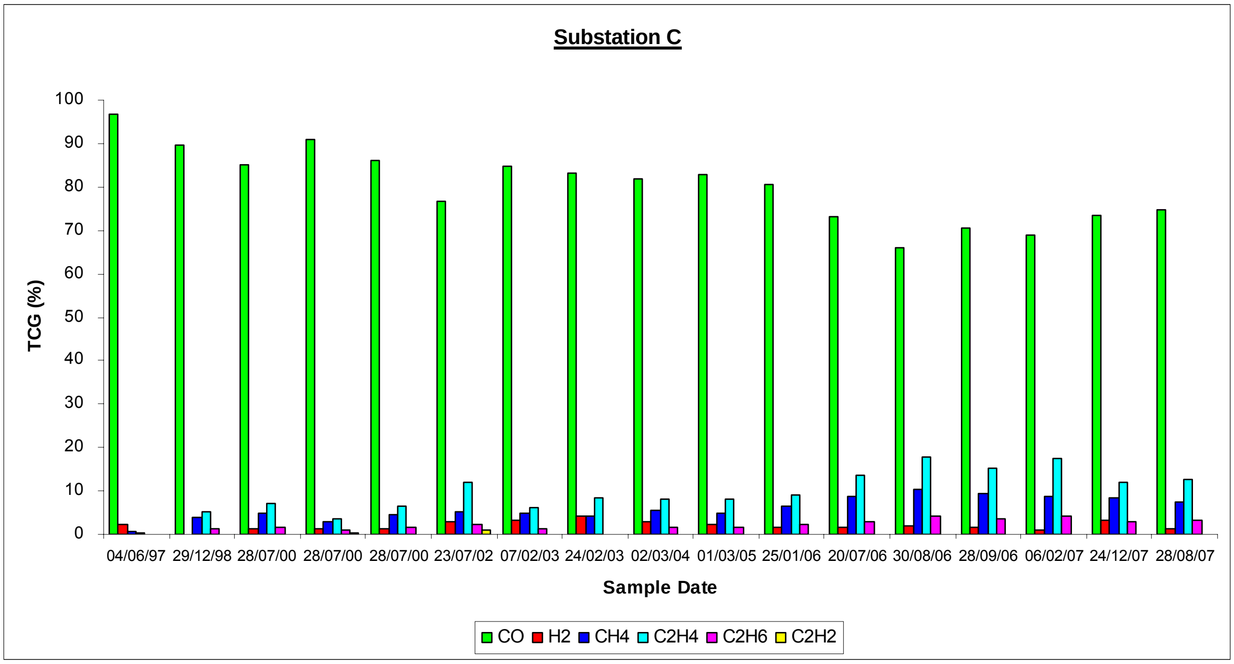
Substation	Circuit	Serial No	Manufacturer	Year of Manufacture	Years in Service	Ratio	Rating(MVA)	Condition	Plan	Overall	Thermal	Dielectric	Mechanical	Comments
A	1	21	A	1977	31	1/1	10	Normal Aging	None	9	3	3	3	None
B	2	31	A	1977	31	1/1	10	Normal Aging	None	9	3	3	3	None
C	3	41	A	1977	31	1/1	10	Fault	Immediate Intervention	106	100	3	3	Thermal fault possibly a bare metal type
D	4	51	A	1977	31	1/1	10	Normal Aging	None	9	3	3	3	None
E	5	61	A	1977	31	1/1	10	Fault	Monitor	66	3	3	60	Mechanical fault possibly hoop buckling on LV winding monitor with SFRA
F	6	71	A	1977	31	1/1	10	Fault	Monitor	36	30	3	3	Early stages of a developing thermal fault.
G	7	81	A	1977	31	1/1	10	Normal Aging	None	9	3	3	3	None
H	8	91	A	1977	31	1/1	10	Normal Aging	None	9	3	3	3	None
I	9	101	A	1977	31	1/1	10	Fault	Monitor/Plan for rectification	96	3	90	3	Possible dielectric fault -- perform PD measurements
J	10	111	A	1977	31	1/1	10	Fault	Immediate Intervention	106	3	100	3	Possible dielectric fault and bushing needs urgent replacement Perform PD measurements
K	11	134	A	1977	31	1/1	10	Normal Aging	None	9	3	3	3	None
L	12	112	B	1979	29	1/1	10	Normal Aging	None	6	3	3	0	Questionable power factor values. Needs to be Confirmed/retested
M	13	113	B	1979	29	1/1	10	Normal Aging	None	6	3	3	0	SFRA not performed
N	14	114	B	1979	29	1/1	10	Normal Aging	None	6	3	3	0	SFRA not performed
O	15	115	B	1979	29	1/1	10	Normal Aging	None	9	3	3	3	None
P	16	116	B	1979	29	1/1	10	Normal Aging	None	9	3	3	3	None
Q	17	117	B	1979	29	1/1	10	Normal Aging	None	9	3	3	3	None
R	18	118	C	1979	29	1/1	10	Suspect	Monitor	13	10	3	0	Possible early stages of thermal fault with high exciting currents
S	19	119	C	1979	29	1/1	10	Normal Aging	None	6	3	3	0	SFRA and power factor not performed hence assessment is limited
T	20	210	C	1979	29	1/1	10	Normal Aging	None	6	3	3	0	
U	21	211	C	1979	29	1/1	10	Normal Aging	None	9	3	3	3	None
V	22	22	C	1979	29	1/1	10	Normal Aging	None	9	3	3	3	None

Condition	Definition	Score
As new	No damage and accelerated deterioration	**1**
Normal aging no performance issues	Reasonable for age - no action required	**3**
Suspect with minor issues with performance	Some aging - monitor - but not urgent	**10**
Suspect with Major issues with performance	Identified aging, risk for failure	**30**
Unacceptable	Unacceptable aging deficiencies	**100**

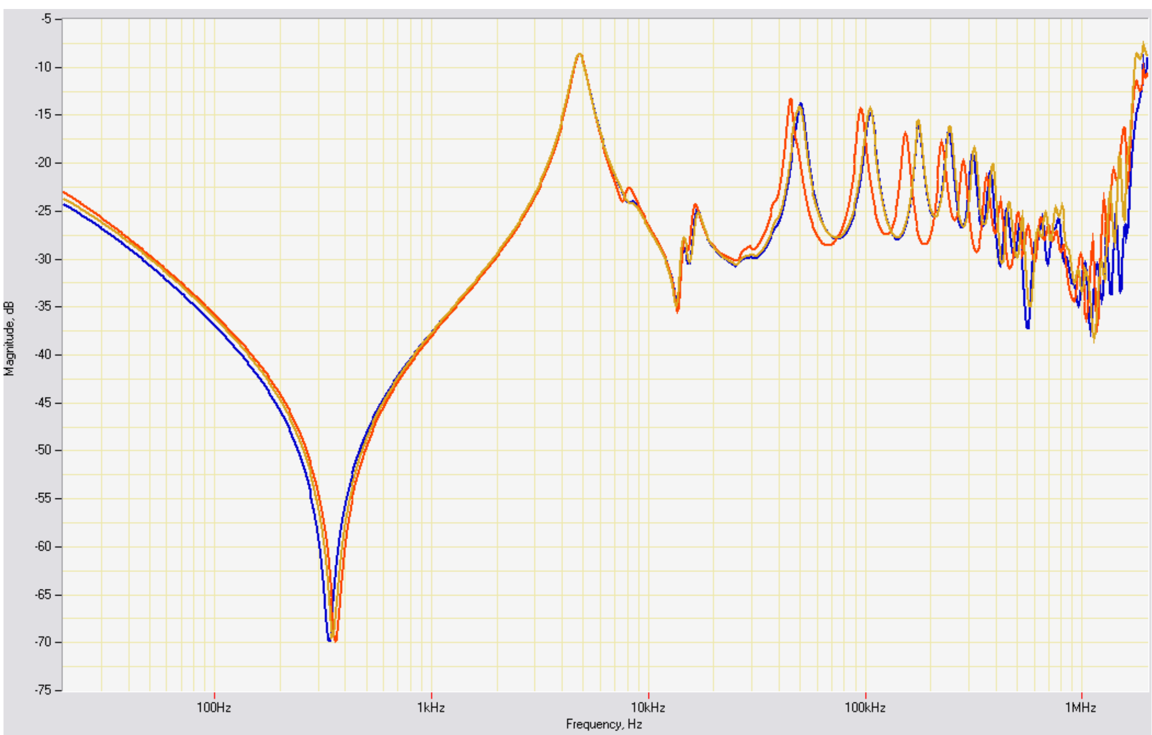
The ranking of these transformers clearly indicates units with dielectric, thermal and mechanical concerns. The assessment gives an overall score based on the transformers condition. The two concerns in terms of thermal and mechanical concerns are discussed.

Substation C – Serial Number: 41

The DGA signature is typical of a localised thermal fault. The high levels of ethylene and methane are indicative of a bare metal type fault. The fault is most possibly a circulating current between core-frame-tank problem. It was not possible to perform an insulation resistance test as the core was internally earth.



Substation E – Serial Number 61



The comparison between the phases finds that the responses demonstrate a characteristic pattern and has good correspondence across most of the frequency range for the White and Blue phases. The responses for the Red and White phases do not indicate winding deformation.
<u>However, there is a very noticeable frequency shift on the Red phase. This shift is typical of a hoop buckling. The frequency shift on the Blue phase is indicative of winding deformation.</u>

INTERESTING CASES STUDIES

Case Study One: Corrosive Sulphur

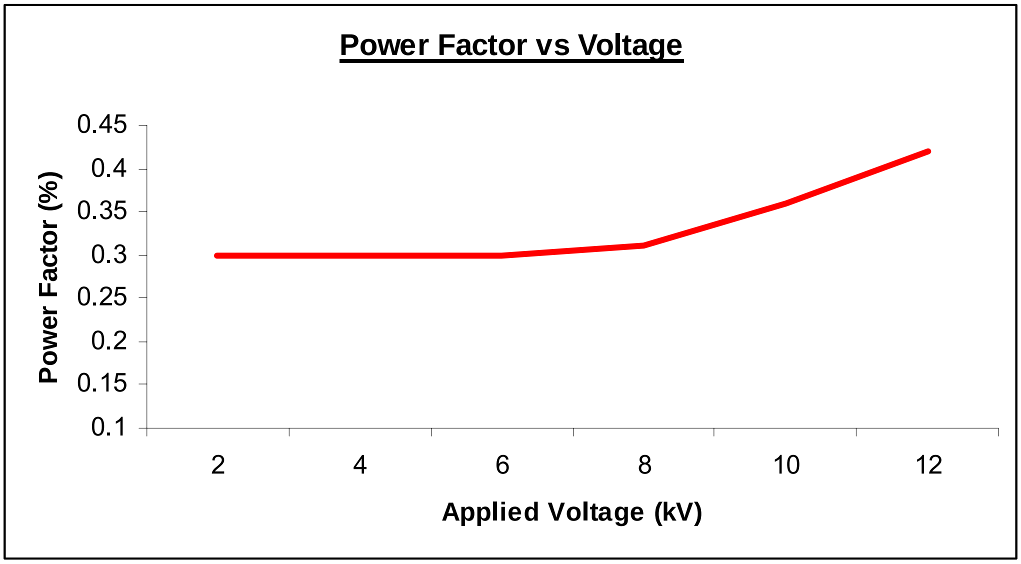
This transformer was confirmed as a transformer that was operating with corrosive sulphur. The transformer shows signs of abnormal gassing. It was decided to remove the transformer from service to perform electrical tests to assess the deterioration caused by the corrosive sulphur. The following electrical tests were performed:

(a) Winding insulation
(b) Bushing insulation
(b) Exciting current
(c) Sweep Frequency Response Analysis (SFRA)
(d) Impedance

Electrical Tests

All electrical tests were within acceptable limit except for the power factor measurements. Given below are the power factor values for this transformer.

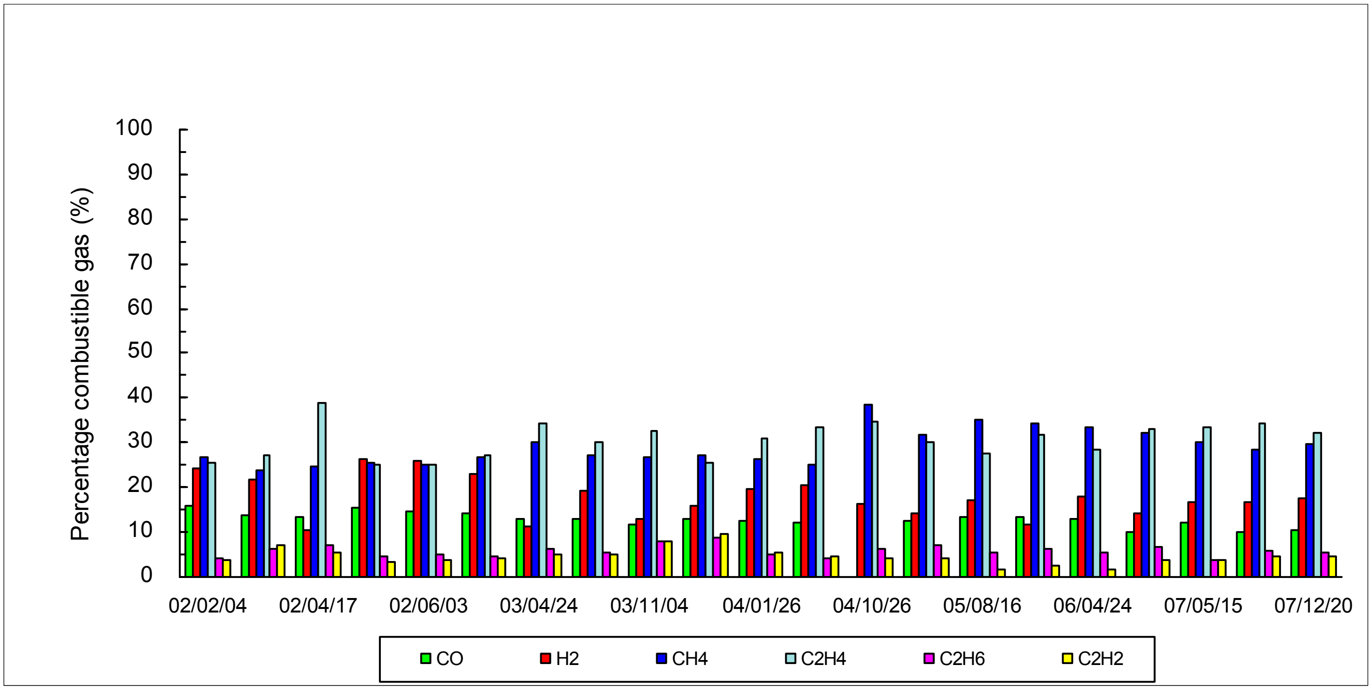
Voltage(kV)	Power Factor (%)
2	0.30
4	0.30
6	0.30
8	0.31
10	0.36
12	0.42



It is clear that the power factor values display a characteristic tip-up that is indicative of possible ionization with the degradation of paper/oil insulation system. This deterioration can be attributed to the corrosive sulphur.

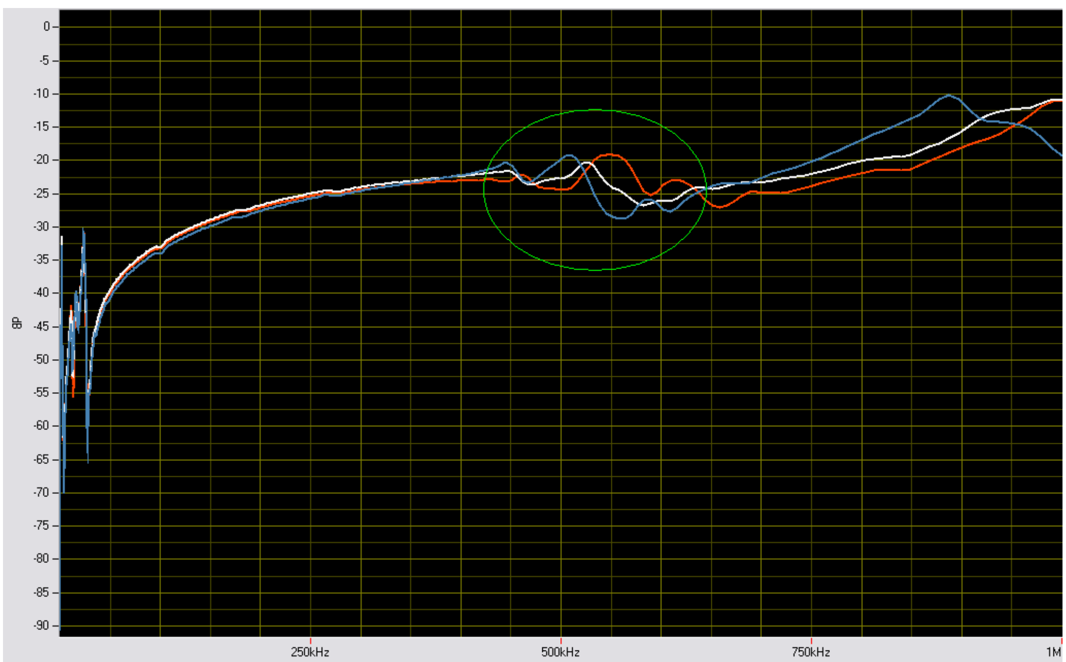
Dissolved Gas Analysis

The dominant hydrocarbon in the DGA signature is ethylene and methane in similar quantities with high levels of hydrogen. The relative levels of theses gases indicates a localized thermal fault possibly a ‘covered conductor’ type problem eg. winding fault. Further, the ratio of CO and CO2 indicates possible involvement of paper.

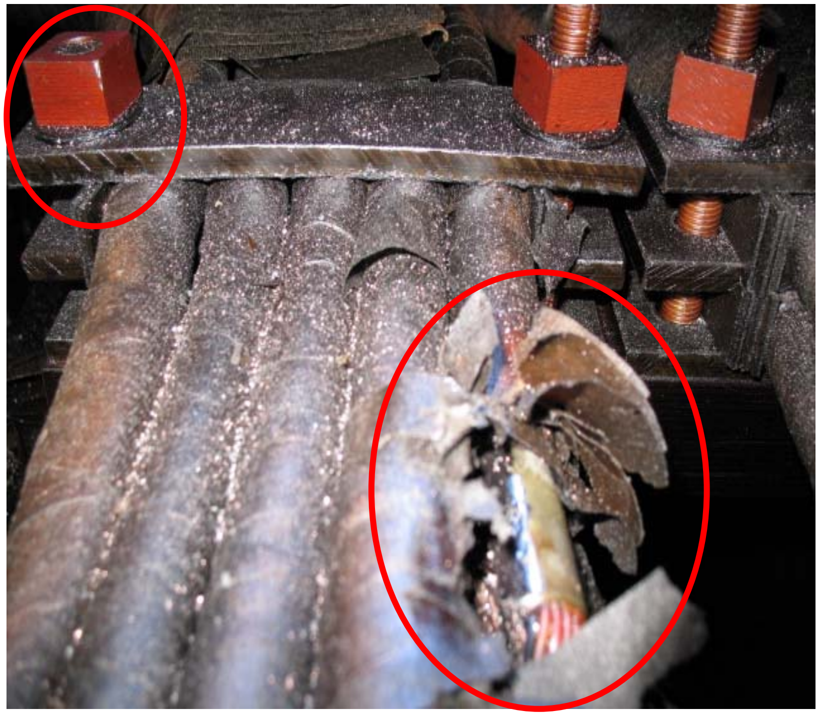


Case Study Two: Tap Winding and Lead Deformation

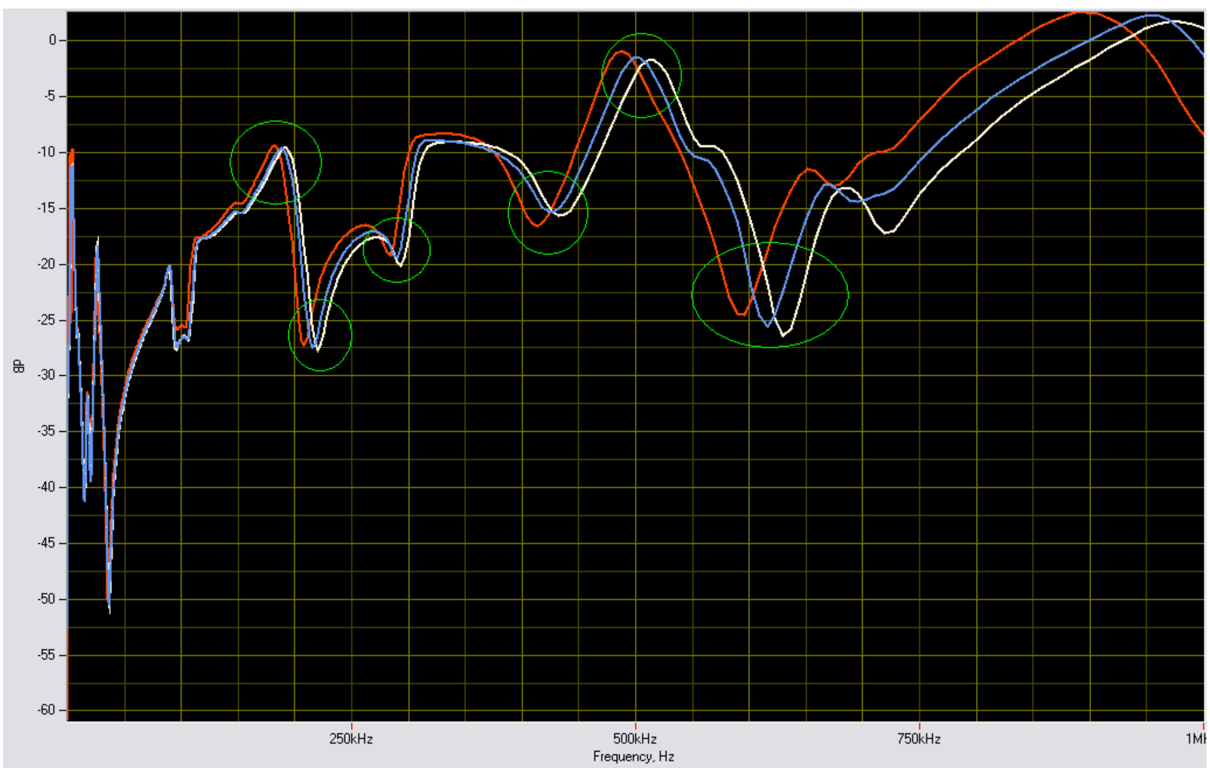
This transformer failed in service and was tripped by pressure relay. The DGA showed clear indication of an internal flashover. Only SFRA was performed on this unit as the DGA results already warranted an internal inspection.



SFRA response clearly showed deformation of the tap leads.



An internal inspection revealed that there was severe damage to the tap lead. As a result of this damage it was recommended that the tap windings responses be measured to assess the condition. The figure below clearly identifies tap winding deformation. The fault that started on the tap leads resulted in the collapse of the tap winding.



CONCLUSION

Transformer condition assessment program can be effectively introduced by using this two phase approach. This method of condition assessment can be implemented irrespective of the amount of information. It allows utilities to finally have answers to the following situations:

- When to have maintenance outages
- How to respond to a protection trip
- To know capability to increase transformer rating
- To know when to replace (5, 10, 15 years) transformers

An added advantage is that this method forces the utilities to make the bold move to condition based maintenance. A further advantage is the risk assessment and residual life can finally be achieved through sound engineering principles.

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