TRANSFORMER CONDITION AND LOADING EVALUATION

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ABSTRACT

In asset management, the manager must balance the condition and function of an asset with the value the asset provides. It is the continued service of the asset, such as a transformer, which must be balanced against the loss of life and replacement cost. The paper details a risk-centric approach which should be considered by any transformer owning organizations.

INTRODUCTION

This paper discusses how to maximize transformer operational capabilities by evaluating both the thermal capability and situational condition of substation power transformers. Increased loading naturally leads to increased operating temperatures; the result is accelerated transformer dielectric aging and an increase in failure rates. Power transformers are typically large capital items, with a long lead time for delivery, and may have a significant impact on system reliability. If they are unavailable for service in an unplanned manner replacement is difficult, costly and time consuming.

TRANSFORMER POPULATIONS AND LOSS OF LIFE

Utilities may have large fleets of power transformers. Many of these transformers are highly loaded or perhaps even overloaded. Furthermore, the age of many units are in excess of original design life and have unclear asset conditions. The end result is possible operational use which brings accelerated ageing and runs transformers much closer to failure. The ability to estimate loss of life for dielectric insulation due to load and associated temperature is the first step to recovery.

Loss of life assumes that the life of a transformer is a well-defined and well understood property of transformers. Sadly, this is not the case. Simple application of a standard such as IEEE C57.91-1995 leads to a 20.6 year expected insulation life for a transformer loaded to rated power. It follows that thermal insulation deterioration *will* occur. However, many transformers are not fully loaded, and average age at failure is usually in well beyond 20.6 years.

The problem of loading, and expected transformer life, usually arises when a short term load is applied to a transformer – either as a result of system contingencies or planned outages. The condition of the transformer must be considered before overloading and must be continually monitored during overload. Utilities must have the wherewithal to proactively monitor transformers that has been overloaded and ensure they remain 'Fit for Purpose'.

SOURCES OF TRANSFORMER INSULATION AGEING

'Normal' ageing of a transformer would be at the rate of one year per year. That is, the insulation has a predetermined expected life, and after one year of in-service operation, one year of that life has been used up. The idea is that after all the years have been used, the transformer is no longer fit for purpose. It's a good approach, but relies on an assumption as to what the expected life of the cellulose is. Accelerating factors increase the rate at which the expected life is used up. Transformer ageing is primarily caused by heat, but is also dependent on both moisture and oxygen. The contribution to overall ageing of each factor is a function of temperature. The three effects are:

- Pyrolisis: direct thermal ageing of cellulose, which increases with temperature
- Oxidation: depending on the level of oxygen dissolved in the oil – up to a factor of 3x 'normal'
- Hydrolysis: related to moisture – up to a factor of ~15x 'normal'

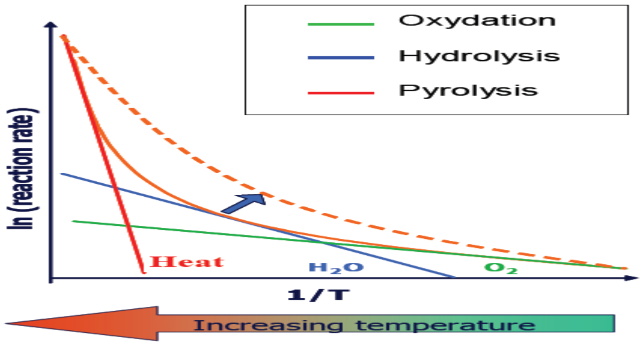

Figure 1 Effects of Ageing factors at Different Temperatures

Oxygen appears in transformers as a result of free breathing unit operation, or as a byproduct of poor seals in a sealed unit. Moisture appears in oil as a result of ingress at gaskets, seals etc, but is also generated by the deterioration of cellulose within the transformer. The factor for accelerated thermal ageing, F_{AA}, of cellulose is given by:

$$F_{AA} = e^{\left[\frac{15000}{110+273} - \frac{15000}{HST+273}\right]}$$

Where HST=Hot Spot Temperature (°C) (1). Oxygen acceleration factor is given by a value between 1 and 3, depending on the level of oxygen within the unit. Moisture acceleration factors depend on the weight of moisture, as a percent, in dry paper:

$$C_{paper} = 2.173 \times 10^{-7} \times e^{\left[\frac{4725.6}{(T+273)}\right]} \times \left(\frac{C_{oil}}{18 \times 0.702 \times e^{\left[\frac{1498}{(T+273)}\right]}}\right)^{0.6685} \times 100$$

Where T is the temperature in °C (2) and the moisture acceleration factor, M_{AAF}, is given by (3)

$$M_{AAF} = 0.72 + 0.934 \times C_{paper}$$

DATA COLLECTION AND VALIDATION

Doble Engineering recently partnered with San Diego Gas & Electric's Asset Management department to better understand transformer loss of life analytics as part of their transformer fleet asset management program. On line condition monitoring provided dissolved gas levels, transformer and local ambient temperatures and loading information.

There are a number of assumptions within the IEEE C57.91 loading guide which must be addressed to provide useful and meaningful results. In addition, the team extracted real time data from the SDG&E SCADA system to allow for automatic update and *what-if* analysis under high system stress scenarios. The data is then used to predict how future temperatures may vary from *expected values*; consequently, situational problems can be identified before they happen. Data is collected from thermal sensors and on line DGA and moisture sensors across a range of transformers.

Particular transformers may be seen through simple charts linking load, ambient temperature, calculated hot spot and measured hot spot temperatures. The figure shows some key parameters.

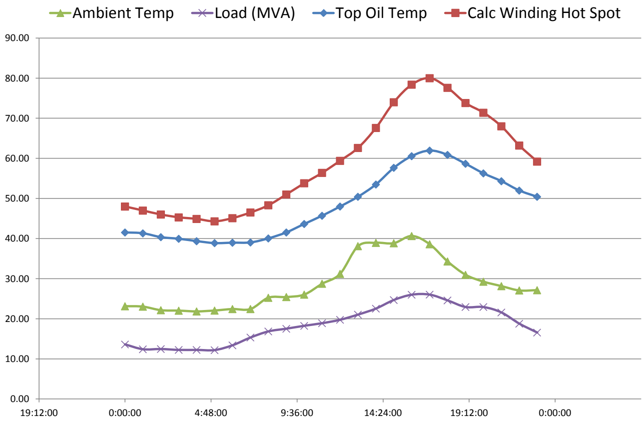

Figure 2 Key Temperature Parameters and Load Recorded for a Daily Cycle

Predictive temperature assessment looks at the present thermal condition of the transformer and predicted loading to give a 24 hour cycle of predicted temperatures:

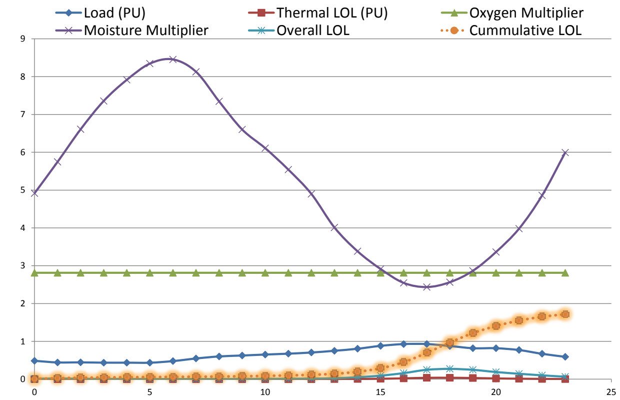

Figure 3 Predicted Loss of Life and Thermal Condition

The load cycle is used to predict temperatures. On line monitoring gives historic temperature values under known load and a predicted loss of life for the three combined factors can be identified.

The loading model is validated against actual temperatures and a cumulative loss of life can be calculated. This is most easily performed in a per unit mode and in the figure it can be seen that loss of life is heavily dependent on load and approaches 2 pu at the end of a 24 hour period. This means that in 1 day we have used almost 2 days of insulation expected life.

We discovered that the feedback between calculated and measured hot spot temperatures provides the greatest insight-- the IEEE loading guide has good prognostic value but a strict application may be too conservative.

BUBBLE FORMATION

The updated C57.91 from 2011 has a new bubble formation algorithm which is dependent on moisture content of the paper, the gas content of the oil and the pressure at the hot spot within the oil based on atmospheric pressure and local oil depth. Bubble formation is an issue if the temperature of the hot spot exceeds that at which bubble formation is likely to occur (2).

$$\theta_{bubble} = \left[\frac{6996.7}{22.454 + 1.4495 \ln W_{WP} - \ln P_{pres}}\right] - \left[\left(e^{0.473 W_{WP}}\right)\left(\frac{V_g}{30}\right)^{1.585}\right] - 273$$

Predicting the hot spot temperature, and knowing the local atmospheric pressure and the dissolved gas content, a bubble formation temperature may be calculated. Loading may then be managed to reduce risk of bubble formation.

PREDICTING PERFORMANCE

Each utility or operator has its own guidelines and standards for transformer operational limits: hot spot temperature, top oil temperature, loss of life per 24 hours. By using 'what if' analyses on transformers, based on latest loading, condition and temperature information, analyses can be run to determine where optimal loading lies. The approach is to look at a range of load values, in per unit, and predict the resulting temperatures and ageing factors.

Yellow	120.00	105.00						1750	10
Red	130.00	110.00						1800	1
Maxpu	Max HS	Max Top Fluid	Thermal Equivalent aging hours	Thermal aging factor	Avge O2 multiplier	Average H2O multiplier	Overall aging factor	Overall Equivalent loss of life hours	Hot Spot θ above Bubble θ
0.701695	84.78	71.79	0.32	0.01	2.81	4.13	0.96	2.69	94.64
0.845951	87.27	74.37	0.44	0.02	2.81	4.04	1.18	3.33	88.57
0.990207	91.30	78.16	0.71	0.03	2.81	3.95	1.61	4.53	79.12
1.134463	101.24	83.94	1.36	0.06	2.81	3.88	2.45	6.91	67.78
1.278719	112.27	91.20	3.07	0.13	2.81	3.81	4.18	11.77	53.42
1.422976	124.29	99.41	7.86	0.33	2.81	3.77	8.99	25.30	38.31
1.567232	137.32	108.57	21.95	0.91	2.81	3.75	23.18	65.23	23.41
1.711488	151.43	118.71	64.85	2.70	2.81	3.72	65.92	185.47	7.51
1.855744	166.68	129.89	198.78	8.28	2.81	3.70	200.01	562.76	-8.41

Figure 4 Limiting Factors for Transformer Loading

Where a particular limit is exceeded, the data is colored red; where we are approaching the limit, data is colored yellow. This gives a broad indication of how much load can be added to a transformer under spike or increased ambient temperature conditions.

DISCUSSION

Application of available standards and condition monitoring systems has allowed for better predictive analysis and asset management of a fleet of power transformers. By using known conditions and algorithms for analysis of ageing factors, transformers may be loaded closer to limiting values and life management of the units improved.

REFERENCES

1. IEEE Standard C57.91 Loading Guide for Mineral Oil Filled Power Transformers
2. EPRI Guideline for Life Extension of Substation equipment
3. CIGRE Electra, April 2012, "Furanic Compounds for Diagnosis"