A Practical Approach to Condition and Risk Based Power Transformer Asset Replacement

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Abstract- As with other utilities, National Grid is faced with a fleet of transformers, many heavily loaded, where the present age of many units is in excess of the expected design life. National Grid is pursuing a practical and iterative approach to replacement based on risk: a combination of condition and criticality. The process is iterative and makes best use of condition data and subject matter expert opinion, combined with consequence of unplanned unavailability. The result is a list of transformers targeted for strategic replacement and an 'action plan' for all units based on tactical response which may include system reconfiguration.

I. INTRODUCTION

National Grid, as with many other utilities, is faced with a fleet of power transformers, many loaded to near nameplate levels, where the present age of many units is in excess of the original expected design life. 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 [1]. Owner/operators balance the predicted power transformer population performance with the need for investment [2]. Consequently, it is critical that there is a strong link between subject matter experts (SME's) in transformer condition and those who plan for capital investment in order to efficiently invest.

Age and Condition

The age profile for the operating distribution substation power transformers in one company are displayed in Fig. 1. The age of the unit is sometimes a useful indicator of the condition of the insulation and of the number of faults a transformer may have seen. As can be seen from Fig 1, there are many units of significant age; many of these units, on subsequent review, are in relatively good condition.

A program to identify candidates for replacement, and development of action plans for each unit is a critical element of the fleet management process. Analysis of test and related data gives a good indication of the 'fitness for purpose' of each unit. A poor condition unit can be 'brought forward' in a planned replacement program. By examining the consequences of failure (e.g. safety/environmental, reliability, financial) a unit may be 'deferred' as it has little impact as a result of its failure. It is the balance of likelihood of failure and consequence of failure that is at the heart of risk management.

Fig. 1. Distribution Transformer Age profile

Risk Analysis

Risk may be defined as the combination of likelihood of an event and the consequence of an event [2]. The event we are interested in is the unplanned unavailability of a substation power transformer. This unavailability may be caused by an internal event, such as a flash over as a result of insulation degradation, or by an external event, such as a through fault. The situation is complex – a through fault in a new unit may be survivable, whereas the same fault seen by a unit with poor condition unit may lead to failure [3]. In this paper we use the condition and age of a unit as a proxy for the likelihood of an event: a poorer condition unit being assumed to be more likely to be unavailable in an unplanned manner. The consequence is a combination of safety, reliability and financial impacts. Combining likelihood and consequence gives an indication of risk for an individual unit.

II. TRANSFORMER CONDITION

Identifying or discerning the true condition of a transformer, and its likely capability to perform the function for which it was placed in service, is not a trivial matter. It is the role of the subject matter experts (SME's) to determine the condition of an individual unit. Knowledge of condition is reviewed based on:

- Results of DGA and other condition tests
- Knowledge of maintenance activities and findings
- Knowledge of operating history
- Manufacturer or design specific characteristics
- Status of accessories – bushings, arresters, cooling
- Assumed aged status of the paper insulation
- Local and subject matter expert opinion

Transformer failure rates by voltage class are known from a number of surveys [3], but we need to apply such knowledge with caution – does the data in the survey apply to the transformer in question, based on manufacturer and design considerations?

A recent technique to identify anomalous condition is to combine the various DGA values into a single score [4]. This score is based on ratios of the key gases and is tuned to detect poor condition. We have a transformer population which is generally in good condition and as a result we expect the DGA scoring algorithm to identify a relatively small number of units as ‘anomalous’. This is the first test of such scoring system – does it give sensible results? We know we do not have many poor condition units – the algorithm should reflect that knowledge.

The condition of a transformer is analyzed under three main headings, covering dielectric, thermal and mechanical aspects. Automation of data analysis is being undertaken through implementation of Digital Inspection’s Cascade™ product. However, the role of the SME’s in reviewing data and algorithm output is crucial in ensuring that the system detects anomalous condition and we do not overlook poor units or address units which do not need to be addressed.

The current condition of a transformer leads into the question: how long is the unit likely to remain in service?

Fitness for purpose

The role of the transformer must be integrated into the condition analysis: if a poor condition transformer is likely to perform adequately until a station is retired, which may be in a few years based on system planning considerations, then no action may be necessary. What is key is reviewing the data and analyzing risk in a formal way so that the decision made is backed up with an audit trail.

Application of condition monitoring on poor condition units – including on-line DGA and on-line PD – may give adequate indication of a change in condition which indicates incipient and imminent failure. However, not all failure modes allow for such graceful degradation in condition that we can identify a degrading situation and then act. In such cases where a failure must be avoided, condition monitoring may be inappropriate and rapid change out of the transformer commenced.

Maintenance may be appropriate for those conditions where the maintenance activities address the degradation process – such as decoking contacts in tap changers.

Table 1 summarizes the approach to condition analysis, which is based on two key elements: the SME’s analysis of all available information and the age of the unit. The condition score from the SME lies between 1 and 10 while the age multiplier lies, generally in the range 1-2.5. Age is used as a

multiplier as it takes into account any through faults and paper ageing. This is a very simple but based on a design age of 60 years, we factor in age so that a 60 year old unit is twice as likely to be in poor condition as a new unit. Clearly the age of a unit carries a lot less weight than the condition analysis as it is an indicator rather than a driver of condition.

TABLE I
TRANSFORMER CONDITION SCORES

Condition		
Review	Score	Age
Good condition	1	
Condition gives cause for concern	5	(60+Age)/60
Poor or questionable condition	10	

Overall the condition score range resulting is: 1 – 25 (the higher score for a poor condition 90 year old transformer).

II. TRANSFORMER IMPACT

National Grid presently utilizes an impact algorithm which takes into account several factors including environmental factors, reliability impact (load) and financial factors to produce a transformer criticality score. The weighting factors described below, and in Table II, are evolving and are subject to change with experience gained and/or as better information becomes available:

An MVA score is provided to each unit based on a 20 MVA being a typical larger distribution unit; larger units are considered more critical based on load and replacement costs. The formula (nameplate MVA+20)/20 gives a score generally in the range 1-2 for most National Grid distribution units.

Highly utilized (HU) transformers are transformers that operate at 100% nameplate load or more during peak load periods, even if only for a short duration. For example, a transformer that operates at 114% load will receive a score of 1.14. Combined MVA and utilization gives an indication of load at risk, which is a proxy for possible reliability concerns.

Environmental factors (EF) would include oil containment issues, spill control measures etc. The scoring system results in either a 1.0 or a 1.2 depending on whether the unit in question has any environmental factors or not.

TABLE II
TRANSFORMER IMPACT SCORES

MVA	Utilization (HU)	Environmental Factors (EF)
(20+MVA)/20	(100 + percent overload)/100	Present = 1.2 Not present = 1.0

Combined impact scores, given our knowledge of load, are generally in the range 1-4.

II. TRANSFORMER RISK SCORES

Risk scores are calculated by putting in the numbers, for example and multiplying the condition and impact scores. This can be combined into a single step, for example, Table III gives the final risk score for the following two units:

Unit 1 is a 30 year old, 15 MVA unit with environmental factors, loaded to 110% at peak times having an initial condition score of 5.

Unit 2 is an 80 year old, 20 MVA unit with no environmental factors, occasionally loaded to 140% having an initial condition score of 10.

TABLE III
EXAMPLE RISK SCORE CALCULATIONS

#	Condition Indicators		Impact Indicators			Risk Score
	Cond	Age	MVA	HU	EF	
1	5	$(60+30)/60$	$(20+15)/20$	1.10	1.2	17.3
2	10	$(60+80)/60$	$(20+20)/20$	1.40	1.0	65.3

From the ranges of input values to the various factors it can be seen that this methodology typically results in a score in the 1-100 range.

III. EXPECTED & ACTUAL RISK SCORES

We know that most of our transformers are in reasonable condition and have limited criticality and we expect the output of the risk scoring analysis to reflect that knowledge. We hypothesize the output risk scores to distribute mostly at lower values, with maybe 10 percent at higher risk values, as per the chart in Fig. 2. Color coding has been added to assist in evaluation.

In practice, we need to review the mechanisms of scoring and risk balancing. Where possible we automate the analysis, but the role of the SME is critical in interpretation of data – and variation in their analysis of condition will vary resulting scores substantially. This is to be expected as we cannot capture all of the tacit knowledge of the SME's in a set of algorithms. The actual distribution of risk scores is shown in Fig. 3. Color coding has been added to identify units which are considered to be highest risk based on present knowledge. Clearly there are a number of iterations before we reach the expected distribution and we are in the process of revising our risk analysis and weighting process.

Fig. 2. Expected Risk Score Distribution

Fig. 3. Present Risk Score Distribution

The present result is useful in that it confirms a number of units which are high risk, and allows for planning for replacement and action plans in case of failure.

IV. PLANNING ACTION

As a result of the risk analysis a ranked list of transformers is drawn up for 'action'. Actions may include a tactical response such as the application of condition monitoring, or the relocation of a spare to a nearby location. Each unit would be the subject of an action plan – what would happen if the unit were to fail suddenly:

- Identification of appropriate spares
- Identification of appropriate mobile units
- Possible system reconfigurations to address any load not served

In addition the list is used, in conjunction with system planning, to identify candidates for replacement. It is important to include system planning to ensure that units which may be at risk are managed appropriately if they are at a station which could be retired through planning activity. The result of this analysis is a Planned Replacement list, as shown, in Fig. 4. It can be seen that the transformers are not ranked simply by age or size. The risk analysis element and the subsequent planning analysis yield transformers which are a concern but which may have a number of years of service remaining. The transformer colored red is already under a replacement project; the orange color indicates transformers under active consideration.

STA LOC	EQNUM	MVA	VOLT	AGE
Transformer 1	20757	7	23	41
Transformer 2	21601	6.25	23-13.2	37
Transformer 3	23586	12.5	34.5-22.9	23
Transformer 4	23898	9.38	34.5-22.9	21
Transformer 5	20363	3.75	13.8-4.33	59
Transformer 6	21112	10	24.6-4.16	62
Transformer 7	21111	10	24.6-4.16	62
Transformer 8	20113	7.25	23-2.4	62
Transformer 9	20152	9.38	23-4.16	47
Transformer 10	20151	9.38	23-4.16	47

Fig. 4. Replacement Candidate Prioritization

The replacement candidate list should be viewed as flexible: the procedure to determine replacement candidates has a degree of variability and subjectivity and the ranked order is an indication rather than a final determination. Consequently units may move up and down the list of replacements. Given the large capital value and long lead times, it is important that only units which are identified as high risk and of consistent condition are replaced.

IV. CONCLUSION

Applying transformer health and risk scores allows us to provide a basic asset ranking. Transformer health scores are not, by themselves, necessarily an indicator of a transformer problem but they do provide a relatively simple means for scoring large populations of transformers. However the results are not absolute and there is still a need for engineering judgment. Including an indication of consequence allows a risk ranking that is useful to prioritize 'action plans' for significant risks. Planning for replacement is the most drastic element of an action plan – the ranked list is the basis for identification of replacement candidates and subsequent actual replacement.

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