The Locomotive

Transformer Asset Management

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Introduction
The deregulation of wholesale electricity supply has led to a number of changes and new challenges for the electric utility industry and the market participants. The rush to build power plants in the United States has subsided, somewhat, as many energy companies face significant debt.

Today's capital spending on new and replacement transformers is at its lowest level in decades. To make matters worse, the load on each transformer (or its utilization) continues to grow. Power consumption is increasing at a rate of about 2 percent per year. Increased equipment utilization, deferred capital expenditures and reduced maintenance expenses are all challenges facing today's utility industry.

Many utilities are beginning to develop their own Life Cycle Transformer Management programs. This asset management approach is typically a three-step process:

1. Screening Process to prioritize the transformer fleet.
2. Condition Assessment of individual transformers.

In previous Locomotive articles, we have discussed the adequacy of the U.S. transmission system, the cause of transformer failures, the aging transformer fleet and a life management program (“An Analysis of Transformer Failures, Part 1 and 2,” Spring and Summer 1999; “Keeping The Lights On, An Action Plan for America’s Aging Utility Transformers,” Winter 2001). This article will address Step 1 of Life Cycle Management — the screening process, using a risk assessment technique.
Risk Assessment

There have been a number of excellent papers written in recent years on the assessment of transformer life and the techniques employed to establish transformer condition and decide on remedial action. [1, 2, 3, 4, 5, 6] In addition, a number of engineering organizations (such as the Institute of Electrical and Electronics Engineers Transformer Committee, CIGRE and the Electric Power Research Institute) are developing their own guidelines for evaluating the condition of individual transformers. [7, 8, 9, 10] Many of these are listed in the references for this article.

In order to identify and prioritize the aging transformers, a screening process is often used. The screening could be as simple as ranking the transformers by age. However a more comprehensive screening can be accomplished with a Transformer Risk Assessment.

Analytical Process

There are many different risk assessment methods and strategies available to the utility industry for a large family of power transformers. The following method is a simple procedure, which utilizes a modified Delphi technique to help identify the transformers that need additional condition assessment, additional testing, or other actions that need to be taken in order to bring the entire population up to an acceptable risk level. Each transformer in a group can have its risk index compared, or ranked, to all other transformers on the company’s balance sheet.

Risk, in the most general sense, is defined as “future’s uncertainty.” It has two basic components: the frequency, or how often undesirable events occur, and their severity or consequences. For example, every transformer has an end-of-life, so the severity of the event is known. The risk comes from not knowing when it will occur — the frequency of failure.

Relative Ranking of various issues can result in a better risk management strategy. The first step in developing a risk assessment program is to identify the two major components:

1. Frequency Factor: This involves analysis of known history, statistical data, and judgment by experts — specific characteristics that contribute to the overall risk.
2. Consequence Factor: the possible repair or replacement costs of the transformer, plus any other site-specific potential costs.

Cause of Transformer Failures

As a risk-ranking example, we have plotted the cause of transformer failures, from our claims data for 1995 through 2000. This is a log-log scatter plot, or sometimes referred to as an "F-N curve" (frequency — number curve). The number of failures for each cause is on the X-axis, and the dollars paid for each cause is on the Y-axis. According to our claims database, the Line Surge (or Line Disturbance) is the highest risk for all type of transformers. The category includes switching surges, voltage spikes, line faults, and other T&D abnormalities.

Chart 1:

Hartford Steam Boiler prefers the frequency/severity plot for risk ranking because it allows for discrimination of high frequency vs. high severity events. For those who prefer a single-number ranking system, the Transformer Risk Index (TRI) is a number that can be used to rank the entire transformer population. The TRI is a product of the...
Consequence Factor (CF) and Probability Factor (PF), or: 
TRI = CF x PF. The end result is a prioritization ranking 
which helps determine the extent to which each transformer 
is inspected, tested, maintained and operated in the future.

Consequence Factor
The Consequence Factor is comprised of two parts — the 
probable maximum loss, in dollars, and the strategic impact 
of the transformer. Strategic impact includes intangible 
issues such as system reliability, critical customers, and 
public safety (such as hospitals). The probable maximum 
loss would include such items as the possible repair or 
replacement costs of the transformer, plus the environmental 
damage and clean-up costs. Additional factors would be 
damage to adjacent equipment, lost revenues and litigation 
costs, as well as any other site-specific potential costs. (For 
generator step-up transformers, the lost revenue can far- 
outweigh any and all other costs.)

The probable maximum loss can be developed for any 
transformer or substation based on historic data. But the 
strategic impact is a subjective multiplier that must be 
developed by the utility. Sometimes a committee of asset 
managers and engineers is used to make this judgment. The 
committee can establish the strategic issues, and then 
assign a range of multipliers for each issue.

The “system reliability” might have a multiplier of 1.0 to 1.5, 
“critical customers” might have a range of 1.0 to 1.3, and 
public safety might have a multiplier of 1.0 or 2.0 (if the 
substation served a hospital, or not). Of course additional 
strategic issues that affect the consequence can also be 
added to the formula. Note that strategic issues only affect 
the outcome or severity of a failure. These issues do not 
affect the probability of a failure.

As an example, if the probable maximum loss for a certain 
power transformer is $300,000 and the “committee” assigned 
strategic impact multipliers of 1.3, 1.3 and 1.0, the 
Consequence Factor would be: 300,000 x 1.3 x 1.3 x 1.0 = 
507,000.

Probability Factor
There is no single scientific method available to determine 
the exact probability of failure, or to calculate the end-of-life 
of a power transformer. However, a probability factor can be 
created as part of this screening technique, by first 
developing a list of critical issues that are based on the 
known conditions. Each critical issue is then assigned an 
index number, which can be differently weighted. The total 
probability factor is then calculated by multiplying the various 
critical issues.

For example: PF = (CI1 ) x (CI2 ) x (CI3 ) x (CI4 ) x (CI5 ) x 
(CI6 ).

The following are critical issues that can affect the frequency 
or probability of failure, but not the consequence or severity 
of the failure. An index of 1.0 (favorable) to 1.5 (unfavorable) 
could be used for each factor.

- Vintage and Manufacturer may be indicative of 
  transformer quality, material and component condition. In 
  the late 1960’s, industry standards were revised invoking 
  more stringent short circuit duty, which earlier designs do 
  not meet. In addition, some large shell form transformers 
  manufactured before 1978 did not have insulation on a 
  vertical T-beam, which can result in an unintentional core 
  ground.

- Calendar Age can have an effect on the mechanical 
  strength of the transformers insulation and hence its 
  ability to withstand common short circuit forces that are 
  inherent in a transmission /distribution system. 
  Admittedly, a direct correlation between calendar age 
  and insulation deterioration is subject to some 
  uncertainty. But combined with other issues listed here, 
  the calendar age is a significant issue.

- Operating History — Extended periods of overload with 
  an excessive ambient or partial cooling may result in 
  sustained high temperatures, which will degrade the 
  winding insulation.

- Operating Environment — The level of exposure to 
  system faults, and frequent switching operations may be 
  an indication of thermal and/or mechanical degradation 
  of the transformer.
- **Failure History** — Failures of similar transformers in the utility’s asset list may indicate a generic trend. Industry data can supplement internal failure information, particularly when the transformer population is small.

- **Oil Testing History** — Over the past 20 years, many utilities have accumulated a significant amount of data from their oil testing programs. An analysis of the transformer oil’s chemical and physical characteristics can help to diagnose both internal electrical problems and physical deterioration of the oil.

**Considering Risk Factors**

The above index values for each issue are just suggested ranges. Each of these critical issues should be assigned a subjective multiplier that is developed by the utility, based on local circumstances. Again, a committee of asset managers and engineers may be used to make this judgment. Of course, additional critical issues that affect the frequency of failure can also be added to the formula. Note that critical issues do not affect the outcome or severity of a failure.

The committee can also assign weighting factors to certain issues, if they don’t consider all issues to be of equal importance. In our example, if the “committee” assigned critical issue indices of 1.2 (for vintage), 1.25 (for age), 1.1 (history), 1.0 (environment), 1.1 (failures) and 1.1 (oil), the Probability Factor would be: \( PF = 1.2 \times 1.25 \times 1.1 \times 1.0 \times 1.1 \times 1.1 = 1.99 \).

After the two data points (frequency and severity) have been established for each transformer in the system, a frequency/severity plot can be created, such as Chart 2. For those who prefer a single-number ranking system, a typical Top 10 TRI list is shown in Table 1. However, when you use a single-number system, you lose the discrimination of high severity vs. high frequency events, which can have the same numerical index.

<table>
<thead>
<tr>
<th>Substation</th>
<th>CF</th>
<th>PF</th>
<th>TRI (/ 000)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Central T2</td>
<td>448,000</td>
<td>4.5</td>
<td>2196</td>
</tr>
<tr>
<td>Cottonwood</td>
<td>323,000</td>
<td>6.25</td>
<td>2017</td>
</tr>
<tr>
<td>Riplev T1</td>
<td>357,000</td>
<td>5.1</td>
<td>1844</td>
</tr>
<tr>
<td>Baker T1</td>
<td>257,000</td>
<td>6.22</td>
<td>1599</td>
</tr>
<tr>
<td>Lime Creek</td>
<td>275,000</td>
<td>5.66</td>
<td>1557</td>
</tr>
<tr>
<td>Lime Creek</td>
<td>275,000</td>
<td>5.0</td>
<td>1375</td>
</tr>
<tr>
<td>East T2</td>
<td>211,000</td>
<td>6.2</td>
<td>1308</td>
</tr>
<tr>
<td>Tower T1</td>
<td>328,000</td>
<td>3.71</td>
<td>1217</td>
</tr>
<tr>
<td>South T2</td>
<td>286,000</td>
<td>4.2</td>
<td>1192</td>
</tr>
<tr>
<td>Walnut T4</td>
<td>232,000</td>
<td>4.25</td>
<td>986</td>
</tr>
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Action Plan
After the risk assessment is completed, the owner will have a prioritized list of transformers that represents the highest risk. But this does not identify the actual condition or the vulnerability of the individual transformers. The second step in the process, a condition assessment, involves a rigorous inspection and extensive testing of the transformer, which is outside the scope of this article. The results of the Condition Assessment process will help the owner in the last step, the life cycle decisions.

The ideal strategy is a life cycle management program that establishes a loading policy for individual transformers, and provides asset management direction to identify:

a) Transformers that can continue to operate as-is.
b) Transformers that can be modified, or refurbished.
c) Transformers that should be relocated.
d) Transformers that should be retired from service.

References


[10] CIGRE 12-20 Guide on Economics of Transformer Management (draft 23.7.02)

About the Author
William Bartley joined Hartford Steam Boiler in 1971. He is HSB’s Principal Electrical Engineer, specializing in large electrical apparatus, primarily generators and transformers. Bartley is responsible for developing company standards, OEM relations, fleet problems, large failure investigations, repair procedure development, and new testing technologies. He received a Bachelor of Science degree in electrical engineering from the University of Missouri at Rolla. As a senior member of the Institute of Electrical and Electronics, he serves on the Transformer Committee and Rotating Machines Committee.