# POWER TRANSFORMER
# LIFE-CYCLE COST REDUCTION

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## ABSTRACT

*Using long-term thermal loss-of-life analysis, probability of failure analysis, and economic analysis, it is shown that power transformers may be kept in service longer than is the present policy in many utilities. This analysis, coupled with the use of on-line dissolved gas analysers (DGA's) and other improved monitoring equipment can instil confidence in a longer in-service life policy for large transformers.*

*An actual Manitoba Hydro transformer replacement scenario is presented.*

*The cost of the monitoring equipment is significantly less than the potential savings.*

## INTRODUCTION

A recent two-day seminar in Toronto entitled the *Life Cycle Management of Power Transformers*[1] typifies the current interest in determining the condition of power transformers in service, and in minimizing both the cost of keeping them in service and the risk involved.

One thrust of this effort has been to improve on-line gas-in-oil analysis[2]. Another is investigation of the effects of a variety of impurities other than dissolved gasses[3]. A Task Force has generated a report summarizing some of these approaches and other factors that lead to transformer failure[4].

An approach that relates loading to insulation degradation effects is the *ANSI/IEEE Standard Guide for Loading Mineral-Oil-Immersed Power Transformers*[5], that defines a relationship between **winding temperature**, sometimes called 'hot spot temperature', and **rate-of-loss-of-life** of a power transformer. While many would argue that the relationship is imperfectly defined[6],[7], it is nevertheless used by many utilities, as an overloading guideline. In fact the Standard was reviewed and revised slightly to include transformers above 100 MVA, in 1991[8].

As an indication of the validity of the hot spot temperature calculation equations of the Standard, a 1995 Canadian Electrical Association study [9] using fibre optic sensors concluded that "The thermal model provided in the literature [the Standard] for transformers with natural oil circulation is quite adequate to describe the thermal behavior of a transformer subjected to a variable load."

The equations are usually applied over a period of a few hours or a day, because of their complexity. Here, it is shown how to apply the equations in a rational way over much longer periods: years, or even decades. A year-long temperature variation model was developed to facilitate the calculations. It was then possible to track the lifetime of a transformer back into the past and/or forward into the future. This, combined with economic analysis, allows criteria to be developed regarding the best time at which to replace a power transformer due to load growth, i.e. to minimize the cost without significantly increasing the risk.

The transformer replacement analyses considered in this paper are for power transformers greater than 30 MVA on the Manitoba Hydro power system. These transformers typically provide connections between major system voltage levels or high capacity supplies to subtransmission systems. In the Manitoba Hydro system, the normal permissible loading levels of these transformers are 100% of their maximum name plate rating for either winter or summer peak. The permissible contingency loading levels are 125% of rating for winter peak and 100% for summer peak, assuming a summer ambient temperature ≤ 30°C and a winter ambient temperature ≤ 0°C. The basis of this is that during normal <u>or</u> emergency loadings,

> the loss of life of the transformer <u>*over a complete day*</u> must not exceed the **normal** daily loss of life as defined in the IEEE Standards[5],[8].

Figure 1 illustrates the fact that a high rate-of-loss-of-life for a short time is not a significant factor. Over the long term, it is the **integrated** rate-of-loss-of-life that is significant. Over the short term, it is the peak hot-spot (winding) temperature that matters, and whether or not it has caused undesirable contaminating products to form.

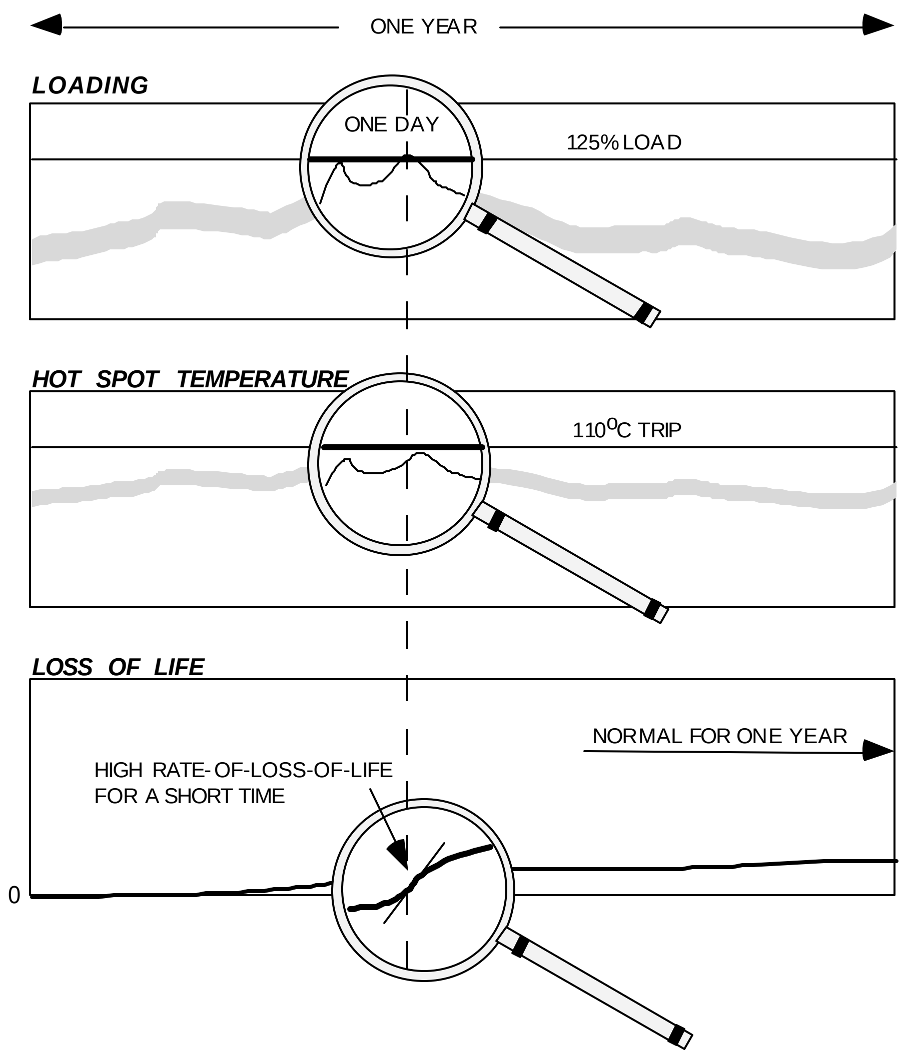


Fig. 1 - Variation of parameters over a whole year.

The recent trend for many utilities is to reduce capital spending, and one area that is being more closely scrutinized is capital expenditures on power transformers. Most utilities desire to make efficient use of the transformers without creating operating or maintenance problems. Load growth causes increased loading on transformers or necessitates the procurement of new transformers. Utilities may opt for increased transformer loadings, which could lead to other transformer problems that were undetected at the lower loading levels.

## LOSS-OF-LIFE ANALYSIS

In order to use thermal loss-of-life equations (not given here because of lack of space: see Reference [8] ), one must either know or assume a loading pattern and an ambient temperature pattern. There are both **daily** and **yearly** aspects to these as discussed below.

### Load Model

The **daily load variation** for Manitoba Hydro and many other utilities has two common forms: a *single hump* shape and a *double hump* shape. A typical double hump shape is shown in Fig. 2. Historical data along with 'load shape' models based on the nature of known customer loads were used in this study.

The **yearly load variation** shown in Fig. 2 includes (for the case used in this study) a two-week outage of the transformer in parallel with the transformer being studied, at the time of the peak winter loading: a worst-case scenario.

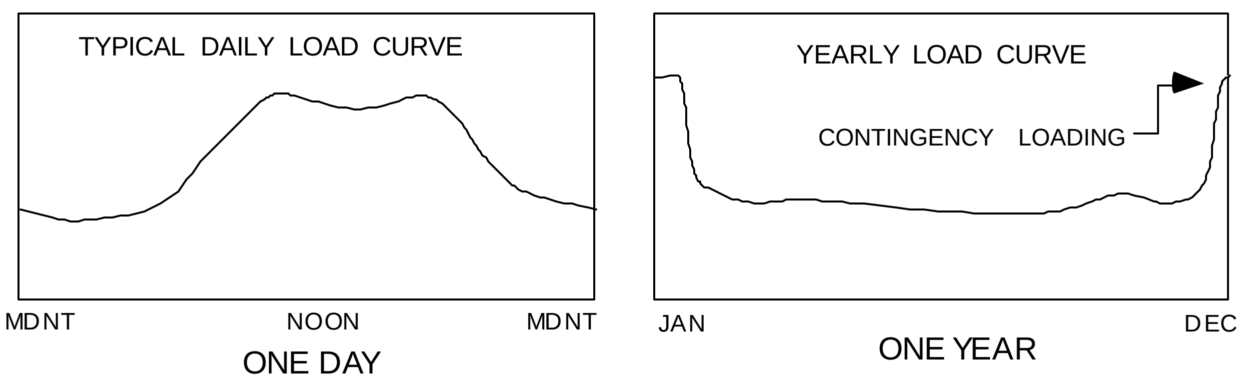


Fig. 2 - Daily and yearly load curves.

The last part of the load model is the **load growth** over the years. Load growth for each year into the future is estimated from known factors, for example planned industrial installations and geographically-related load patterns.

**Ambient Temperature Model**

Similar principles apply here, except that the variations throughout a day and throughout a year are based on long term averages published by Environment Canada[10]. Sinusoidal approximations are shown in Fig. 3. Note that these have to be determined for particular regions. In Manitoba there would be two such regions; one for Northern Manitoba and one for Southern Manitoba.

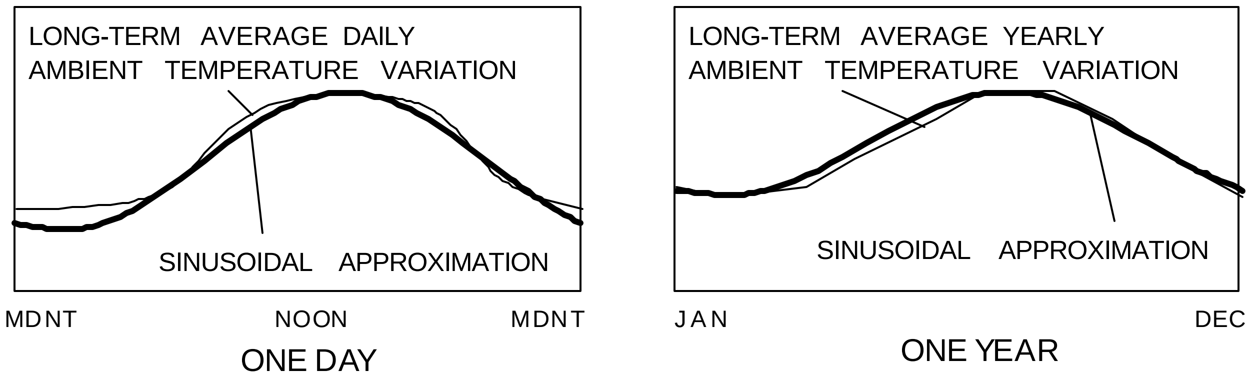


Fig. 3 - Daily and yearly ambient temperature approximations.

**Hot Spot Temperature and Loss of Life**

The winding hot spot temperature is usually the principal factor limiting the loadability of a power transformer. Higher winding hot spot temperatures cause degradation of the winding insulation material and can result in the formation of gas bubbles which facilitate the dielectric breakdown characteristic of the transformer oil.

Industry standards recommend that during **rated load**, the temperature of the winding hot spot should not exceed 110°C or 80°C rise above ambient (with the ambient daily average temperature of 30°C). These temperatures (24hr/day) result in what is defined as the normal loss of life for the power transformer, which works out to be 0.0369% per day [8].

The loss of life is related to the thermal degradation of the insulating paper. For paper insulation, the end of life is defined at the degradation point where the paper has lost half of its mechanical strength. The life of the paper insulation is then only 7.42 years at a continuous winding hot spot temperature of 110°C which increases to 50 years with a continuous winding hot spot temperature of 92°C.

For contingency overload conditions (few days), the industry recommendation is not to allow the winding hot spot temperature to exceed 140°C in order to limit the risk of releasing gas bubbles. However during certain emergency overload conditions, allowing a maximum winding hot spot temperature of 160°C, or even 180°C for a short duration (few hours) may be an acceptable risk for very infrequent occurrences.

Since all utilities do not have the same transformer loading criteria, the maximum allowable winding hot spot temperature limits tend to vary a great deal from utility to utility. This paper outlines a methodology to determine the maximum winding hot spot temperatures, so that **transformer loading criteria** can be safely rationalized taking into account that each utility can accept various levels of risk.

### Case Study Results

To illustrate the argument, a real case has been studied: the Manitoba Hydro Minitonas Terminal Station Bank No. 4. Historical records and future load forecasts were used as data for the plot of **peak load** in Fig. 4. Temperature variations throughout each year were assumed to follow "standard patterns" as described earlier. From this data, **peak hot spot temperature** and **accumulated loss of life** were calculated using the equations of Reference [8]. These results are also shown in Fig. 4.

The present policy is that a transformer will be taken out of service and replaced with a larger unit when the **peak** load in this case (during winter when ambient temperature is less than or equal to $0^{o}C$) exceeds 1.25 per unit. It can be seen that the peak load would have reached about 1.25 in 1996. In anticipation of this, replacement actually took place in 1995. (The removed transformer may be moved to another location, or sold.)

For periods into the future, the loading estimates are based on system load forecasts. Winding temperatures and loss-of-life are calculated in the same way.

The **accumulated loss of life** plot in Fig. 4 up to the replacement year (1995) is very low; less than 1%. From the **peak winding temperature** plot, notice that keeping the transformer in service another fifteen years, to the year 2011, would take the hot spot temperature to just about 150°C, the temperature at which it is sometimes assumed that gas bubbles may start to form in the oil. Correspondingly, the **accumulated loss of life** by the year 2011 is only 4.5%. It is only in the year 2020 that the accumulated loss of life reaches a full 100%.

## ECONOMIC ANALYSIS

### Overview

**Reducing the life cycle costs** of power transformers involves an evaluation of all present and future costs over the expected life of the transformer. **Present value analysis** is used to convert all future costs to equivalent present costs. The scenario with the lowest present value cost is the lowest life cycle cost of the power transformer. The procedure and formulas used in the present value economic analysis are not given here because of lack of space.

The premise of the engineering economic study was to utilize the present value method to examine the cost impacts (savings or debits) that will occur by delaying the scheduled replacement date of a new transformer, by allowing the existing transformer to remain in service after it has exceeded the existing Manitoba Hydro transformer replacement criteria. These studies were completed on a 50 MVA transformer that was replaced in the Manitoba Hydro system in 1995.

The scenarios involve delaying *the replacement date of the replacement transformer itself* from 1-16 years or from 1996-2011 (2011 is the planning horizon year for a 35 year economic study on a transformer initially purchased and installed in 1976). This is accomplished by estimating the cash flows for each scenario from 1995 to 2011. The net cash flows of all costs and residual (salvage) values are discounted for each year to bring them back to present values, which are in 1994 dollars in this study.

Note that the financial end of life (35 years in this study) is usually not the same as the technical end of life.

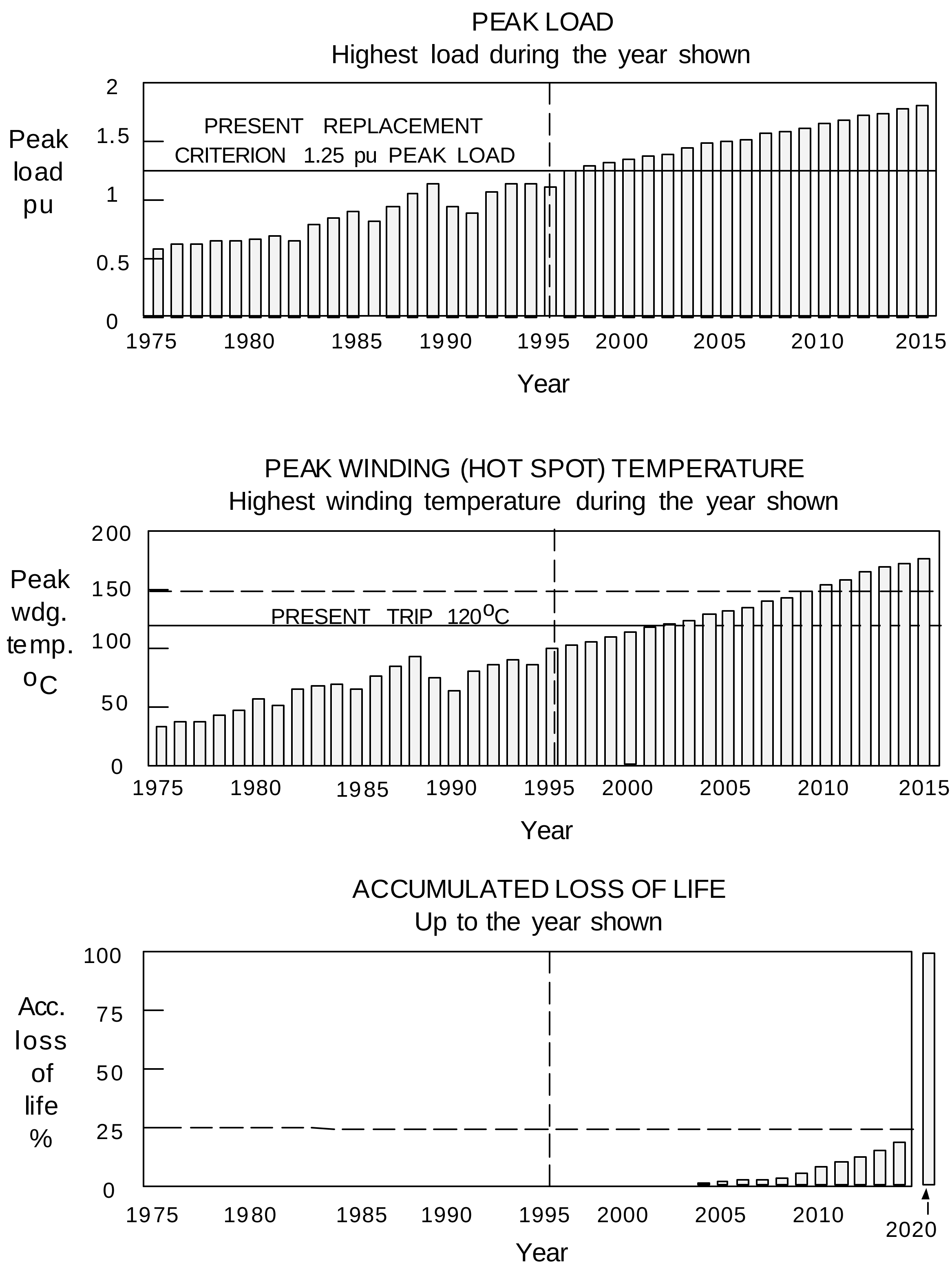


Fig. 4. Peak Load, Peak Hot Spot Temperature and Accumulated Loss of Life

The latter is the life over which the transformer will be permanently taken out of service (failed, not repairable, etc.) usually 35-50 years in Canadian utilities. The financial end of life is the life over which the transformer's residual value is depreciated to zero, and is usually less than the technical end of life.

**Associated Costs**

The engineering economic study included the following costs and residual values associated with the transformer replacement:

1. Purchase and installation (including Engineering) costs of a new (93.7 MVA) transformer in the year the replacement occurs.

2. Residual value of the existing (50 MVA) transformer in the year replacement occurs

3. Residual value of the new transformer at the end of the study horizon, 35 years from the replacement date of the existing transformer in (2) above.

4. Purchase and installation of a sophisticated on-line dissolved gas analyser (DGA) and a sophisticated transformer protection and monitoring device (relay) in the first year of deferment of replacing the existing transformer.

5. Salvage value of the DGA and relay in (4) when the existing transformer is replaced by the new transformer identified in (1) above.

6. Costs associated with the increased load and no load losses as a result of retaining the existing transformer in service longer than originally planned.

It should be noted that operating and maintenance (O & M) costs for planned maintenance were assumed to be the same if either the existing or the new larger transformer were placed in service and were therefore not included as a factor in the analysis. The unplanned O & M costs (repairing oil leaks, etc.) are an infrequent occurrence (e.g. one in 20 years) and were also omitted in this analysis.

Failure costs are also assumed to be the same for either the existing or new transformer and were omitted. This is based on the fact that the statistical failure rate for power transformers (loaded ≤ 160% of rated) during the study period is the same for newer or older transformers as shown in Fig. 5. A detailed ***probability of failure*** analysis has been performed, confirming this statement, using the method of reference [11].

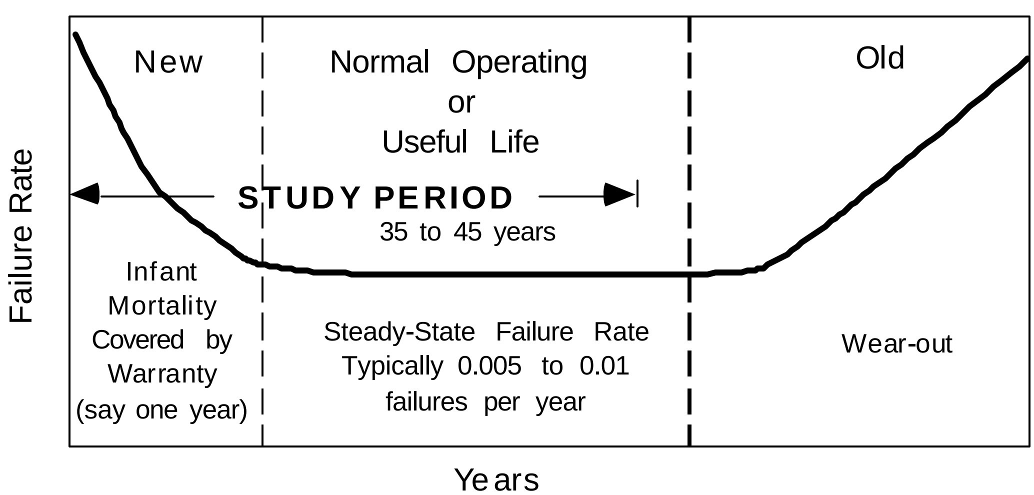


Fig. 5 - Typical failure rate curve.

When compared with other factors such as transformer loss of life analysis, winding hot spot operating temperatures, risk, and other vital non-monetary factors, the net present value will furnish the utility with the knowledge required to identify the least-cost scenario.

It has been determined by others that failure costs can become increasingly important at load levels above 160% of nameplate rating[11]. However for the most part our studies are at load levels below 160% of nameplate.

**Associated Sensitivities**

It is recognized that there is an uncertainty regarding future interest, escalation and load growth factors. This study utilized load growth, interest, and escalation rates forecasted by the Manitoba Hydro corporate experts. More present value studies will be completed to study the sensitivity of the cost savings due to various load growth factors, interest and escalation rates, over different economic study periods of 35, 40 and 45 years.

Various methods of calculating depreciation are possible. The *sinking fund* method was used here, because it most accurately reflects the true market value of the transformer being replaced.

The residual values of the existing and replacement transformers, and the relay and dissolved gas analysis equipment are all taken into account.

**Results of Economic Analysis**

As anticipated, the results of the present value economic study indicated that significant savings could have been realized by delaying the 1995 replacement date of the new transformer by several years.

The results from the 35 year economic study are shown in Fig. 6, where the curves represent the anticipated

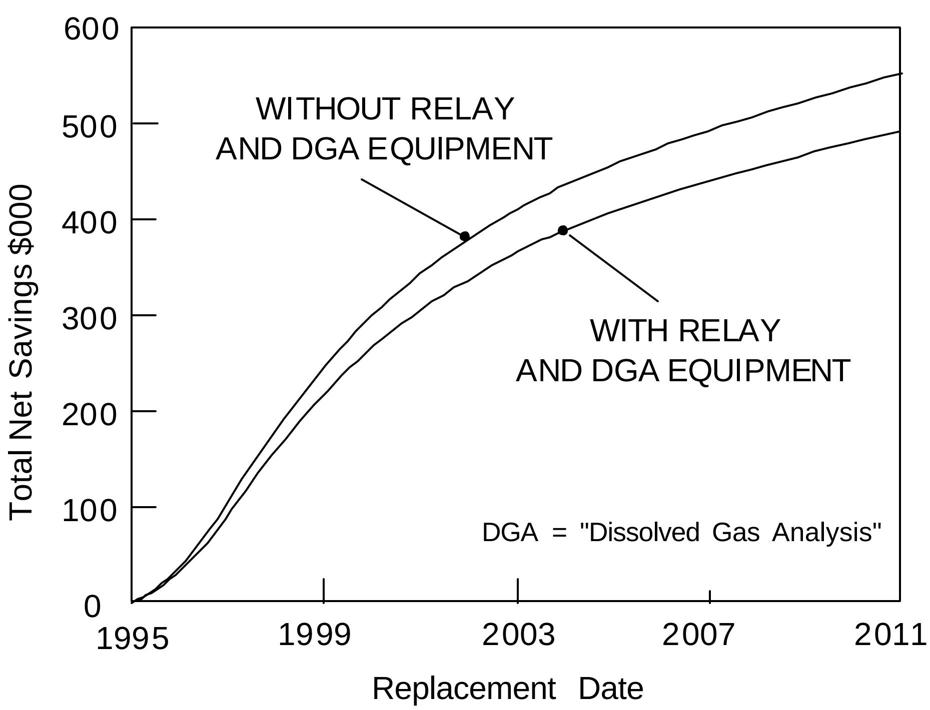


Fig. 6 - Total net savings in 1994 *present value* dollars.

total net savings by delaying the replacement date of the new transformer from 1 to 16 years. In general the longer the replacement date delay, the greater the savings. The savings occurring in year 2011 are $490,000 in 1994 *present value* dollars, even when the cost of a sophisticated monitoring relay and dissolved gas analysis equipment are taken into account.

Although it may not be prudent to attempt to 'significantly and safely' overload a power transformer without the relay and dissolved gas analysis (DGA) devices attached, an option to consider is to allow 'moderate' load increases say from 125% to 135% and not include these monitoring devices to save costs. The dashed line in Fig. 6 shows the additional possible savings.

## PROTECTION AND MONITORING SYSTEM

Even though this analysis indicates that transformers may technically be kept in service longer than is the present policy at Manitoba Hydro, it is not disputed that there is a very small increase in the likelihood of failure of the apparatus. It is therefore recommended that if the longer life policy is adopted, a more elaborate protection and monitoring scheme is justified.

A highly recommended form of monitoring is on-line dissolved gas analysis, and several such devices are commercially available.

Another 'line of defence' is a new multi-function transformer protection and monitoring system that provides not only the usual protection functions (differential protection, etc.) but also continuous monitoring of potentially damaging conditions such as the aforementioned dissolved gas analysis records, high harmonic current content, through-fault current stress, top oil temperature, hot spot temperature, and rate and accumulated thermal loss of life conditions.

In the case studied here, the cost of these protection and monitoring devices is well below the anticipated transformer replacement cost savings, especially considering that such devices can probably be re-used.

## CONCLUSIONS

This paper demonstrates a methodology to quantitatively determine the **savings** that can be realized by keeping power transformers in service longer than is the present practice.

The final recommendation for the particular case studied here was to **delay replacement by nine years**. This was considered to be a judicious choice since the loss of life and hot spot temperature both start to increase exponentially and the 'savings' curve starts to flatten out.

It is shown that it is more **economical to overload** existing transformers and accept the penalty of increased loss of life, than to relieve the loading by installing larger or more transformers. It is recognized that such a new policy, if followed, will lead to a greater dependence on the short-term or emergency overload capabilities of existing transformers and might increase the use of mobile transformers in the event of an outage or failure.

Based on loss of life and probability of failure analyses, it was determined that the risk of failure due to overloading for loading up to 160% of rating, is very small.

Sophisticated on-line **transformer monitoring and relay systems** for dissolved gas analysis and other important transformer parameters can be used as an added information source to safely **improve transformer loadability** and instill confidence in a longer in-service life policy for large transformers. A second benefit is that these devices are capable of alarming to indicate that a **potential problem** is developing so that it can be dealt with before serious damage occurs.

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## BIOGRAPHIES

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