Transformer fleet condition assessment using advanced analytics

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ABSTRACT

Power transformers are expensive (~50% of substation investment) and critical components of our energy infrastructure. Transformers are generally highly reliable, however there are different degradation processes which eventually limit their life. It is critical for end users to understand the risk of failure of their transformers so that resources can be most practically allocated for repair, refurbishment, or replacement. This article provides a case study for a fleet of eight (8) transformers that were above 50 years of age.

KEYWORDS:

condition assessment, life extension, risk mitigation, reliability

Condition assessment is defined as "the method to identify the indications that can be used to determine the extent of the degradation of the components and sub-components of the transformer

1. Introduction

CIGRE 761 technical brochure [1] defines condition assessment as "the method to identify the indications that can be used to determine (and quantify where possible) the extent of the degradation of the components and sub-components of the transformer". During the last decade, there has been a renewed interest in condition assessment as many transformers are approaching their end of life. To maintain the reliability of the electrical power system, it becomes very important to plan for refurbishment or repair of transformers within a certain allocated budget and to be performed during a scheduled outage.

Typically, the process starts with non-intrusive methods such as dissolved gas analysis (DGA), visual inspections, and electrical tests. Further investigation may be required with further electrical testing or more intrusive methods such as internal assessment. Transformer condition assessment should be a structured, consistent methodology to analyse transformer conditions and calculate the transformer risk of failure. The analytical method should be an expert system that incorporates a probabilistic model which always assigns a risk factor to any given transformer – both for long-term reliability and short-term functionality, based on when transformers are classified in the red (urgent), yellow (priority) or green (normal) zones [2]. Transformer candidates for life extension should be assessed for their condition to ensure there are no pre-existing issues and there is significant cellulose life remaining. Based on the assessment, several life extension techniques can be utilised, such as:

1. Replacement of bushings – Bushings have been shown to be a leading cause of transformer failure [3] and should be condition assessed for life extension.
2. Replacement or maintenance of on-load tap changer – Similar to bushings, on-load tap changers are a leading cause of transformer failure [3]. Major maintenance or upgrade to vacuum technology of the on-load tap changer can extend the transformer life. Vacuum on-load tap changers are different from conventional ones in that they use vacuum interrupters, which offer superior performance and reliability compared to conventional tap changers.
3. Digitalisation – Equipping existing transformer with the latest state of the art sensors and monitoring equipment enables proactive/predictive maintenance based on the real-time condition of the transformer [4].
4. Oil reclamation or replacement – The oil inside the transformer can degrade over time, and oil properties can usually be returned to near-new oil values by oil reclamation [5].
5. Cooling upgrades - A design study can determine if the MVA of the transformer can be increased with changes in cooling (such as adding fans) [6]. It is very typical to be able to increase the nameplate MVA rating by 5 - 10% with cooling modifications and with no increase in the winding temperatures (no increased cellulose aging).
6. Low Frequency Heating - The Low Frequency Heating (LFH) technology can achieve large moisture reductions in cellulose for transformers [7]. The process around this technology has matured through experience, and excellent results are regularly achieved in a wide range of transformer sizes, types, and applications.
7. Several other options, such as transformer re-gasketing, are available. Gaskets age over time due to mechanical stress and heat. Aged gaskets can leak, causing moisture and oxygen ingress into the transformer, which can hasten cellulose aging. The complete replacement of all gaskets can be an outcome of condition assessment.

In this article, transformer condition assessment will be described for a fleet of 8 transformers, each of which was over 50 years old and had life extension options determined to improve reliability.

Hitachi Energy's Mature Transformer Management Program (MTMP) uses all early warning signs of transformer monitored parameters and calculates the risk of failure for a fleet of transformers

2. MTMP method of risk assessment

Hitachi Energy's Mature Transformer Management Program (MTMP) [8] uses all early warning signs of transformer monitored parameters and calculates the risk of failure for a fleet of transformers. Estimating the risk of failure of a transformer involves analyzing historical failure data, gaining knowledge of design issues, and interpreting diagnostic test results. The following are the key aspects of the risk of failure algorithm:

A. Risk of short-circuit failure – An assessment of the likely short-circuit strength of the windings and clamping structure based on Hitachi Energy's knowledge of design practices for transformers of that type and voltage, the incidence and magnitude of short-circuit through fault events, historical information, and condition of the windings.

B. Winding thermal condition – This is based on the expected condition of the paper insulation as determined by Hitachi Energy's knowledge of the typical design practices of the time, DGA data and loading history. Aged, brittle insulation is more susceptible to fail under mechanical and electrical stress conditions.

C. Risk of dielectric failure – This is an assessment of the dielectric withstand capability of the transformer insulation system (oil, paper, etc.) and the electri-

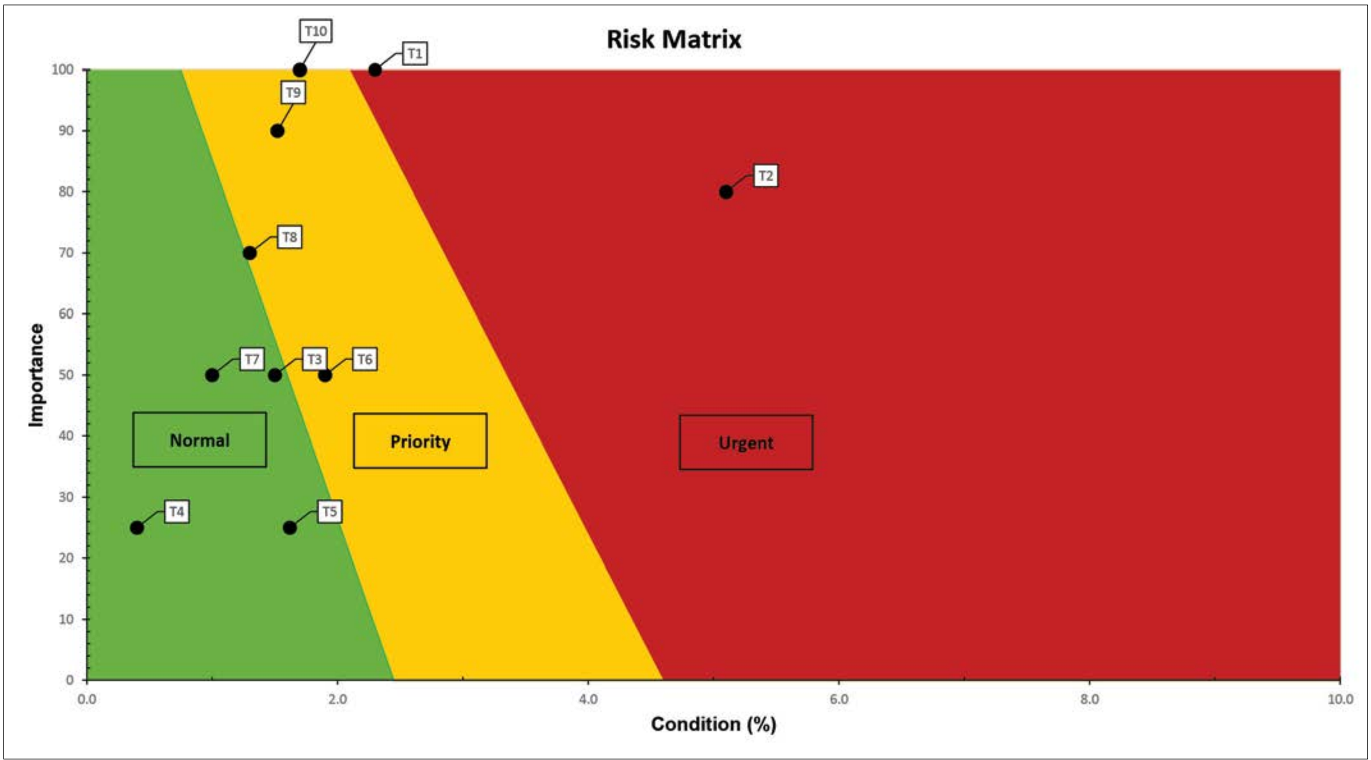

Figure 1. Risk management approach to identify transformer risk of failure.

cal stress imposed by the power system and naturally occurring events.

D. Accessory failures – Failure of transformer accessories such as bushings, pumps, or tap changers may cause a failure or loss of service of the transformer.

E. Random Failure risk – This is due to causes not associated with the design of the transformer or its condition.

This approach to fleet risk screening involves a combination of the risk of failure assessment and the relative importance of a transformer to the utility system. Each transformer in the fleet is assigned a risk of failure and relative importance and displayed on the risk management plot, as shown in Figure 1. Those that fall in the Red Zone are transformers with a combination of high risk of failure and/or higher importance for the system. These are classified as Urgent or those requiring immediate action. The next transformers are those in the Yellow or Priority zone. Action would normally be taken on these transformers as soon as the Urgent transformers have been taken care of. The transformers in the Normal category would typically not require anything other than normal basic maintenance unless circumstances move either the risk of failure or importance to a higher value (into the Yellow or Red Zone).

The risk assessment of the transformers is classified in red (urgent), yellow (priority), or green (normal) zones based on their risk of failure algorithm

3. Transformers under investigation

The transformer population considered in the study update consisted of 8 transformers, as listed in Table 1.

- Included is the relative importance of each transformer that was provided by the end user.
- Units 1- 6 are duplicate single-phase Generator Step Up (GSU) transformers.
- Units 7 and 8 are 3 phase service station transformers.

Table 1. Transformers considered in the fleet risk assessment

ID No.	Position	Importance	MVA	Year of manufacture
1	T1 - A	75	23	1968
2	T1 - B	75	23	1968
3	T1 - C	75	23	1968
4	T2 – A	75	23	1968
5	T2 – B	75	23	1968
6	T2 – C	75	23	1968
7	SS-1	100	1	1968
8	SS-2	50	1	1968

Table 2. Transformers considered in the fleet risk assessment

ID No.	Position	Furan (ppm) current estimated	Estimated DP	Ageing
1	T1 - A	2.019	405±60	Severe
2	T1 - B	0.693	535±58	Significant
3	T1 - C	1.820	418±61	Significant
4	T2 – A	1.364	453±60	Significant
5	T2 – B	0.731	528±58	Significant
6	T2 – C	1.508	441±60	Significant
7	SS-1	0.056	798±85	Minimal
8	SS-2	0.070	778±73	Minimal

To estimate the technical end of life of transformers, dissolved oxygen and water content in paper (WCP%) is required

Because of the age of the transformers, estimation of the cellulose condition was required. When assessing the quality of the solid insulation, it is best practice to consider the average length of the glucose chains of the cellulose molecules as the determining quality indicator [9], normally denoted as the Degree of Polymerization (DP) value. It is common to assume that the DP value of new and dried kraft paper is in the range of 1000-1250 and that the DP value of 200 denotes a region where the solid insulation has reached end-of-life [10].

Based on the age of the units, kraft paper was assumed. Measured Furan values, CO_2/CO trends, and correlation with oil/winding temperature were used to estimate the current DP value as shown in Table 2, using the L. Cheim et al. [11] model.

To estimate the technical end of life of these transformers, dissolved oxygen and water content in paper (WCP%) is required. However, the WCP% was not provided by the laboratory, so a worst-case value of 1.25% was used as suggested in [12] for transformers ≥ 230kV. Online techniques to measure the water content of transformer insulation are desirable because other methods, such as dielectric response, require that the unit be taken offline and electrically isolated from the network. This is not required when installing water activity or %RS sensors. These will be very helpful in improving the technical end-of-life estimation.

Oxygen values were obtained from the DGA reports. The calculated end of technical life is listed in Table 3.

Based on the expected years remaining, it can be noted that all the units are ideal for life extension based on condition assessment. However, one needs to assess other factors which may call for early replacement.

3.2 Risk assessment for transformers under investigation

The probability of failure for the priority and urgent units is broken down as listed in Table 4 and as shown in the risk matrix in Figure 2.

3.2.1 Risk of short-circuit failure

One of the more common types of failures in power transformers is a winding failure caused by the forces associated with a through fault. The transformer test results did not show any signs of past short cir-

Table 3. Calculated life expectancy for the transformer fleet considered

ID No.	Position	Estimated DP	Oxygen O_2	WCP %	Hot spot temperature	Years remaining
1	T1 - A	405±60	30,600 ppm	1.25%	72ºC	9.9
2	T1 - B	535±58	31,000 ppm	1.25%	72ºC	11.6
3	T1 - C	418±61	31,400 ppm	1.25%	72ºC	9.6
4	T2 – A	453±60	29,500 ppm	1.25%	72ºC	10.4
5	T2 – B	528±58	28,400 ppm	1.25%	72ºC	11.5
6	T2 – C	441±60	28,400 ppm	1.25%	72ºC	10.1
7	SS-1	798±85	30,900 ppm	1.25%	72ºC	13.9
8	SS-2	778±73	29,600 ppm	1.25%	72ºC	13.8

Table 4. Calculated probability of transformer failure

ID No.	1	2	3	4	5	6	7	8
Position	T1-A	T1-B	T1-C	T2-A	T2-B	T2-C	SS-1	SS-2
Accessory	0.63	0.63	0.63	0.76	0.77	0.62	1.76	1.76
Dielectric	0.24	0.24	0.24	0.33	0.43	0.68	2.07	1.37
Thermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Miscellaneous	0.70	0.30	0.50	1.00	0.80	0.30	1.20	0.90
Short circuit	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04
Total	1.62	1.22	1.41	2.14	2.05	1.65	5.08	4.07

cuit events. The main factors contributing to short circuit risk of failure are the following: degree of polymerisation, MVA, historical loading, manufacturer, and age. All units showed low short-circuit risk.

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3.2.2 Thermal winding aging risk

An important factor in the risk of failure is the condition of the paper insulation. Aged transformers with brittle insulation and/or loose windings are more likely to experience a failure under the same through-fault conditions than compared to other transformers of the same design that do not have brittle insulation or loose windings. This principle was incorporated into the risk of failure analysis by the thermal winding risk factor. As with the short circuit risk factor, this factor is only one component of the risk of failure equation, and so only the relative comparisons of the factor for the different transformers are meaningful. The main factors contributing to the thermal risk of failure are specific DGA gasses and oil preservation type. There is no associated thermal risk to this fleet of transformers.

3.2.3 Risk of dielectric failure

The risk of dielectric failure involves both design and condition issues. Both design

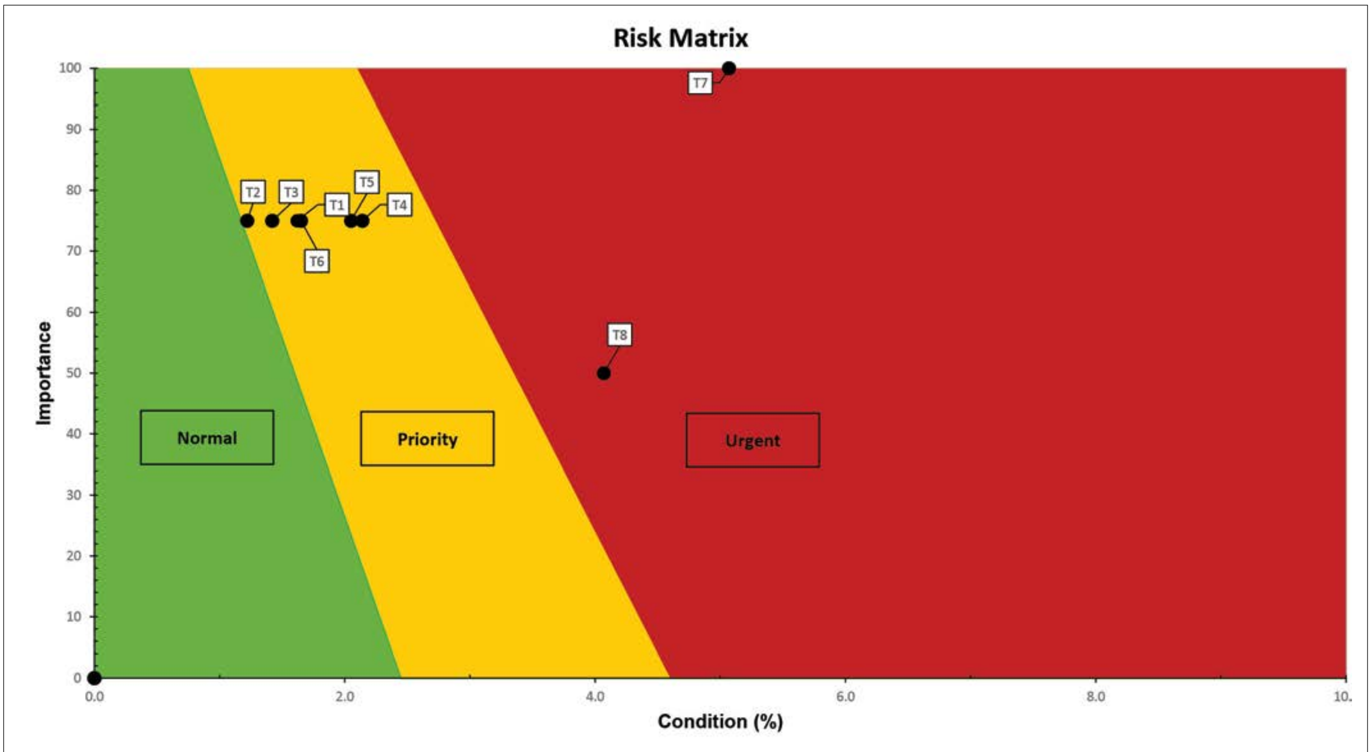

Figure 2. Calculate the risk of failure for transformers under investigation.

The main factors contributing to the thermal risk of failure are specific DGA gasses and oil preservation type

knowledge and historical information were used in this evaluation, as well as the diagnostic test data. Variation of historical diagnostic test results also affects the dielectric risk.

The main factors contributing to the dielectric risk of failure for these transformers are the following: acetylene levels, oil quality, and insulation power factor values.

3.2.4 Accessory failure risk

Accessory failure refers to the loss of service due to either the failure or operational breakdown of an accessory. The main factors contributing to accessories risk of failure were the following: bushing power factor results (or lack thereof), accessories service age, Load Tap changer (LTC) type, and LTC step count.

3.2.5 Miscellaneous failure risk factor

One of the environmental risks associated with transformers involves the loss of transformer dielectric and cooling fluid in the tank through tank leaks or around gasket joints in the auxiliary equipment. Small leaks pose little risk to the failure of a transformer, however if the transformer enters a vacuum condition, moisture may enter the tank and can, over time, increase the risk of dielectric failure. In addition, oil leaking into the ground of the substation could pose an environmental hazard. In severe leak cases, a fire in the substation can spread to other equipment or control buildings because of saturated oil in the soil. Rust could develop into a leak if left unchecked. Leaks can also develop in radiators, tanks, or other components due to vibration, rust, or transportation.

Another concern in this risk category is the presence of PCB in the oil. PCB fluids were widely used as non-flammable dielectric fluids from the 1930s through the 1970s. While PCBs do not cause failures, their use is banned or limited due to bioaccumulation and health concerns.

The number of leaks or rust spots and their severity as well as the presence of PCBs, were used to determine this risk, as shown in Table 4. SS-1 and T2-A showed the highest levels of oil leaks.

3.3 Recommendations for transformers under investigation

The below specific actions were recommended for the transformers:

- Plan for oil samples/DGA on the units on a yearly basis.
- Include in oil analysis power factor testing at 25°C and 100°C. This will provide evidence of oil contamination vs oil aging.
- All LTC units with a count exceeding 100,000 should receive a full inspection report.

While PCBs do not cause failures, their use is banned or limited due to bioaccumulation and health concerns

Table 5. PF test results for T2 transformers

Date	2004	Latest test result	Difference %
T2-A	0.38%	0.55%	45%
T2-B	0.33%	0.84%	154%
T2-C	0.55%	0.81%	47%

- Perform oil leak repairs as needed. Besides the environmental concerns, oil leaks cause oxygen to enter the unit, which accelerates insulation aging. Oil leaks can also cause dielectric failure if the leak is big enough and the oil drops below the active part.
- The PCB content of the units is of concern. Any spill with oil that is 2 ppm or greater is considered a PCB spill. Since most of the units are leaking, T1 and SS units can be considered as PCB spills. The units are not in oil containment pits. Also, if the oil is removed from these units (for maintenance, internal inspection etc), then the oil cannot go back into the transformer. It is recommended to seek PCB mitigation as soon as possible. The oil containment system needs to be considered immediately.
- Based on a CIGRE bushing reliability study [13], approximately 78% of bushings fail within 40 years of operating service. The bushings on the units are assumed to be the original bushing (i.e., the age of these bushings is > 53 years). There is also a high likelihood the bushings contain PCB in the oil. These bushings should be planned for replacement.
- Insulation power factor and capacitance should be performed periodically. It is one of the leading methods for detecting moisture and contamination within a transformer. The last test on the T1 transformers was from 2004 – this should be repeated and compared to the 2004 results for any discrepancy. The last insulation power factor test on the T2 transformers showed an increase in the LV to ground values compared to previous results. The values are shown in Table 5. While the limit is 1.0% [14], the large increase could indicate a future problem. It is recommended to investigate by performing a dielectric frequency response (DFR) test on T2-B and T2-C.
- A low water content of mineral insulating oil is necessary to achieve adequate electrical strength and low dielectric loss characteristics, extend insulation life, and minimise metal corrosion. The T2-B and T2-C latest oil samples tested moisture beyond the recommended limits set by IEEE standard C57.106-2015. These units should be processed to remove the excess moisture.
- Numerous studies have shown water and oxygen to be the most aggressive factors causing the acceleration

Table 6. Recommended short term action plan

Position	ID#	Possible risk mitigation actions								
		[L1] = 6 months, [L2] = 1 - 2 Yrs., [L3] = 2 - 3 Yrs., [L4] = 3 – 5 Yrs								
		PCB mitigation	PF and cap. test	Replace bushings	Consider replacing unit	Fix oil leaks	Re-gasket unit	Add inhibitor	LFH	DFR
1	T1-A	[L2]	[L2]	[L3][3]		[L1][1]	[L1][1]	[L2][2]		
2	T1-B	[L2]	[L2]	[L3][3]		[L1][1]	[L1][1]	[L2][2]		
3	T1-C	[L2]	[L2]	[L3][3]		[L1][1]	[L1][1]	[L2][2]		
4	T2-A	[L2]		[L3][3]		[L1][1]	[L1][1]	[L2][2]	[L2]	[L4]
5	T2-B	[L2]		[L3][3]		[L1][1]	[L1][1]	[L2][2]		[L4]
6	T2-C	[L2]		[L3][3]		[L1][1]	[L1][1]	[L2][2]	[L2]	[L4]
7	SS-1				[L1]					
8	SS-2				[L1]					

- 1 = Re-gasketing unit should be performed during fixing oil leaks
- 2 = Add Inhibitor after PCB Mitigation is performed. Installation of silica-gel breathers is also an option.
- 3 = Replace bushings during oil leaks fix, if possible.

Numerous studies have shown water and oxygen to be the most aggressive factors causing the acceleration of cellulose deterioration

of cellulose deterioration [15]-[16]. Oxidation inhibitors can be added to mineral insulating oil to slow the formation of oil sludge and acidity under oxidative conditions. They are used particularly in transformers partially or freely exposed to air during service life. Since all the units are free breathing, adding oil inhibitors will extend the life of the oil.

- Acetylene (C_2H_2) is created from arcing in oil or paper at very high temperatures (above 1000°C). The presence of acetylene in the SS transformers indicates an incipient fault. It is recommended to replace these units due to these gassing issues, age, and PCB content.

Based on the fleet assessment, the following short-term action plan is recommended to the end user, as listed in Table 6.

3.4 Return on investment for life extension interventions

A principal concern for asset managers is the return on investment (ROI) for life extension actions. Below, a Net Present Value (NPV) analysis is carried out for the given recommended actions:

- Fixing oil leaks
- Transformer re-gasketing
- Addition of oxygen inhibitor
- Perform dryout using Low Frequency Heating technology
- Addition of silica gel breather

Table 7 lists the estimated improvements in oxygen content and WCP% after performing these actions.

The Net Present Value (NPV) of a replacement deferral through life extension can be calculated as

$$PV_{defferal} = \left(\frac{1}{(1+i)^{Lc}} - \frac{1}{(1+i)^{Le}}\right) \times 100\%$$

where

- Current Life Remaining L_c = 9.9 years
- Extended Life remaining after intervention L_e = 20.33 years
- Life Extension achieved = 10.43 years

Table 7. Improvements in transformer parameters after life extension interventions

ID No.	Oxygen O_2	WCP %	Hot spot temperature	Years left	Life extension achieved
Pre-intervention	High O_2	1.25%	72°C	9.9	~ 10 years
Post - intervention	Medium O_2	~1%	72°C	20.33	

Contrary to intuition, it makes financial sense to extend the life of transformers that are nearing the end of life as the financial benefits are collected in the very short term

3.4.1 Variation in discount rate and cost of intervention

Table 8 provides a sensitivity analysis for NPV calculations for variations in discount rate and cost of life extension at a particular hot spot temperature. Favorable NPV results are obtained over a wide range of discount rate variations and cost of intervention.

Table 9 provides a sensitivity analysis for NPV calculations for variations in hot spot temperature. The main conclusions that can be drawn are:

- The highest NPV values appear in the middle of the temperature range (60°C < HST < 85 °C) and do not correspond to the absolute longest life extensions.
- Maximum absolute life extension in years is achieved in the lower range of temperatures considered. The remaining life without any intervention already exceeds the practical limit of 40 - 50 years thus NPV is negative.
- Contrary to intuition, it makes financial sense to extend the life of transformers that are nearing the end of life (ex: current DP=450) as the financial benefits are collected in the very short term.

Table 8. Life extension NPV analysis: Variation in cost and discount rate

		← Discount rate (%) →									
		1%	**2%**	**3%**	**4%**	**5%**	**6%**	**7%**	**8%**	**9%**	**9%**
← Cost of life extension interventions →	1%	8%	14%	19%	22%	23%	24%	25%	25%	24%	23%
	2%	7%	13%	18%	21%	22%	23%	24%	24%	23%	22%
	3%	6%	12%	17%	20%	21%	22%	23%	23%	22%	21%
	4%	5%	11%	16%	19%	20%	21%	22%	22%	21%	20%
	5%	4%	10%	15%	18%	19%	20%	21%	21%	20%	19%
	6%	3%	9%	14%	17%	18%	19%	20%	20%	19%	18%
	7%	2%	8%	13%	16%	17%	18%	19%	19%	18%	17%
	8%	1%	7%	12%	15%	16%	17%	18%	18%	17%	16%
	9%	0%	6%	11%	14%	15%	16%	17%	17%	16%	15%
	10%	-1%	5%	10%	13%	14%	15%	16%	16%	15%	14%
	11%	-2%	4%	9%	12%	13%	14%	15%	15%	14%	13%
	12%	-3%	3%	8%	11%	12%	13%	14%	14%	13%	12%
	13%	-4%	2%	7%	10%	11%	12%	13%	13%	12%	11%
	14%	-5%	1%	6%	9%	10%	11%	12%	12%	11%	10%
	15%	-6%	0%	5%	8%	9%	10%	11%	11%	10%	9%
	16%	-7%	-1%	4%	7%	8%	9%	10%	10%	9%	8%
	17%	-8%	-2%	3%	6%	7%	8%	9%	9%	8%	7%
	18%	-9%	-3%	2%	5%	6%	7%	8%	8%	7%	6%
	19%	-10%	-4%	1%	4%	5%	6%	7%	7%	6%	5%
	20%	-11%	-5%	0%	3%	4%	5%	6%	6%	5%	4%

Life extension of aged transformers is a viable and practical approach and should be based on proper condition assessment and return on investment calculations

- At a higher temperature range, transformers degrade faster, and technical life extension is not financially viable.

3.5 Summary

This article provided a case study for a fleet of eight (8) transformers aged above 50 years using the Hitachi Energy MTMP advanced analytics program. This program uses early warning indicators for transformer monitored parameters to calculate the risk of failure for a fleet of transformers using historical failure data, knowledge of design issues and interpretation of diagnostic test results. The transformers had their condition assessed to ensure there were no pre-existing issues and there was significant cellulose life remaining.

Among these 8 transformers, the GSUs are recommended for life extension due to good return on investment even with low DP values of 450. However, the service station transformers, despite having higher DP values of 798, are recommended to be replaced due to the presence of acetylene PCB in oil, and LTC problems.

Life extension of aged transformers is a viable and practical approach and should be based on proper condition assessment and return on investment calculations.

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Table 9. Life extension NPV analysis: Variation in Hot Spot Temperature (HST)

Initial DP = 450, Kraft paper/mineral oil, cost of life extension= 10% x new transformer cost, discount rate = 5%	
Hot spot (°C) temperature	**NPV @ Moisture reduction from 1.25% to 1%**
50	-10.00%
55	-8.00%
60	1.00%
65	12.00%
70	14.00%
75	11.00%
80	5.00%
85	0.00%
90	-4.00%
95	-6.00%
100	-7.00%
105	-8.00%
110	-9.00%

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