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Mapping as a risk and cost assessment methodology

Proactive transformer mapping assists in operational and financial decision-making

ABSTRACT

Transformers are key assets in a power plant. This article explores the use of mapping transformer populations to quantify the operational and economic costs due to various risk factors, including design, external, and accelerated aging risks. Generation, start-up, and auxiliary transformers are typically designed for specific functions within an operating block in a power plant. The planning, manufacturing, and installation of custom-designed power transformers can take many years to complete. Once in operation, the premature failure of these critical assets before their expected End of Life (EOL) can be devastating to the electric utility or industrial company owner. The mapping process aids in the proactive identification of those transformers that may create the most economical and performance risk. The process helps to identify remediation, conservation, and conditioning actions that ensure that these critical assets function throughout their planned lifetime.

KEYWORDS

mapping, risks, critical assets, transformer aging, accelerated aging, risk assessment, economic cost, maximizing critical assets, preventative maintenance

Mapping is a robust, proactive process that provides an overall picture of potential risks and worst-case scenarios, including financial risks and cost comparisons

1. Introduction

Our January 2020 article [1] focused on the use of the mapping process as a starting point to determine the appropriate remediation and conservation measures that your maintenance team needs to take to ensure a transformer block subjected to accelerated aging performs over the long-term. This article expands on mapping and risk assessment to identify the actions required to extend the operating lifetimes of transformers subjected to other forms of risk, such as design and random external risks. In cases of these risks, the mapping process generates different remediation and conservation strategies to ameliorate and control them. These strategies are then compared so that the option that best balances risks can be implemented with an evaluation of operational and financial considerations. We use a hypothetical example, based on typical field experience, to illustrate these concepts.

2. Types of risk

A transformer block is a complex system. The transformers and auxiliary equipment that comprise an operating block are interconnected and must function as designed for the block to meet operational objectives over an extended period. The issues of accelerated aging and its effect on premature failure have already been addressed in previous articles. A transformer block can also be at risk due to poor design and / or workmanship that create functional weaknesses in a transformer. These, in turn, can cascade throughout the system to cause outages, fires, or other system performance issues in the transformer block. Defects, such as poor welded joints or a defective head gasket sealing, can increase the risk of failure of an individual piece of equipment or the entire transformer block. Random factors, such as lightning strikes, natural disasters, or short-circuiting, create another form of risk that is difficult to predict.

The term end of life (EOL) is **commonly used** to describe the time at which a transformer becomes inoperable. This term is imprecise as it does not convey the actions that can be taken to reduce the risks that most affect a transformer block. These actions could include oil reconditioning and monitoring in the case of accelerated aging or creating redundancy in the system to protect from the abrupt failure of critical assets. A useful term used in this article is the remaining substance (RS), which conveys the concept of a valuable asset that can be consumed or conserved, depending on how the risks are managed. RS was introduced by DTC (Daemisch Transformer Consult company) as a more actionable term instead of relative terms like lifetime or lifespan. It is based on the complete picture taken from the condition assessment resulting from DGA, Furan analysis, oil condition monitoring, and all other available information. It, therefore, is not a simple "index," rather a concise analysis based on the interaction of indicators, experience, and expertise. The decline in RS is exponential if the appropriate measures are not proactively taken. It is important to institute the remedial and / or conservation measures early enough so RS can be preserved in good operating condition throughout the required operating lifetime of the transformer. Field experience suggests that once RS reaches 60 %, the remaining operating life of the transformer is only six years. By taking proper and timely action to manage risk factors, the transformer's lifetime can be extended by another 10 to 15 years. The chart in Fig.1, created by the author, depicts the trajectories of RS with and without conservation measures.

2.1. Type 1 failures

Type 1 failures refer to age-related degradation of electro-mechanical assemblies such as bushings, OLTCs, and solid insulation that can contribute to transformer block failure. The risks caused by accelerated aging are quantified in the mapping process through DGA and transformer fluid testing. These testing procedures provide indications of the level of depolymerization of the solid insulation in the transformer as it cannot be measured directly. The level and rate of exposure of cellulose to aging accelerators such as high temperature, moisture, oxygen (O_2), and acids are the starting points to this process. These influence the physical and electrical properties of the transformer and influence the rate of accelerated aging.

Type 1 risks are accurately determined with today's increased sophistication of test methodologies and technologies.

By taking proper and timely action to manage risk factors, the transformer's lifetime can be extended by another 10 to 15 years

All transformers are exposed to various risks; as they age, their poor design can create functional weaknesses, which can be detected during the operation of the transformer

Once the effects of the accelerators are quantified, measures to conserve the cellulose insulation can be undertaken to extend the lifetime of the transformer. These measures include gas monitoring and oil regeneration. If managed properly, Type 1 risks can be controlled to slow age-related degradation and EOL of a transformer. It is important to understand that even when the proper actions are taken, the transformer will continue to age but at a slower rate than otherwise. This means that the probability of failure from type 1 risks increases with time.

2.2. Type 2 failures

Type 2 failures are associated with inadequate design or poor construction of a transformer, which often causes sudden EOL conditions. The inadequate design of a transformer's cooling system creates overheating, which in turn contributes to accelerated aging and a higher probability of premature failure. Poor workmanship on welding joints results in gateways for oil leakage or the ingress of moisture and atmospheric gases into the transformer, which again causes accelerated aging leading to premature failure. Type 2 risks can develop when the poor design or poor-quality workmanship of a new transformer causes the premature failure of the transformer, resulting in significant lost revenue and repair / replacement costs. Understanding how the new equipment reacts to actual field conditions when connected to existing equipment in the block takes time.

The probability of Type 2 failures begins at a high level, but with time, it declines as the transformer is checked, and adjustments are made to optimize its performance. Proper vetting can take years before the probability of failure reaches normal levels.

2.3. Type 3 failures

Type 3 failures are external influences, such as lightning or short-circuits, which can generate sudden and catastrophic transformer failures. The risk from a lightning strike is unquantifiable due to the uncertainty of the timing and severity of the strike. However, the short circuit of a third-party grid or station transformer also can create this type of risk. Type 3 risk is uncontrollable and random. Type 3 risks are incorporated into the mapping process by focusing on the transformers, which are most exposed to this uncertainty.

The uncertainty surrounding Type 3 failures makes them difficult to predict. As such, the cost in the event of a Type 3 failure is often used as a proxy for the risk. These measures include lost revenue from a loss of power production over some period or the cost of buying power on the open market. Type 3 risk does not increase or decrease over time and can be thought of as a uniform probability distribution over the lifetime

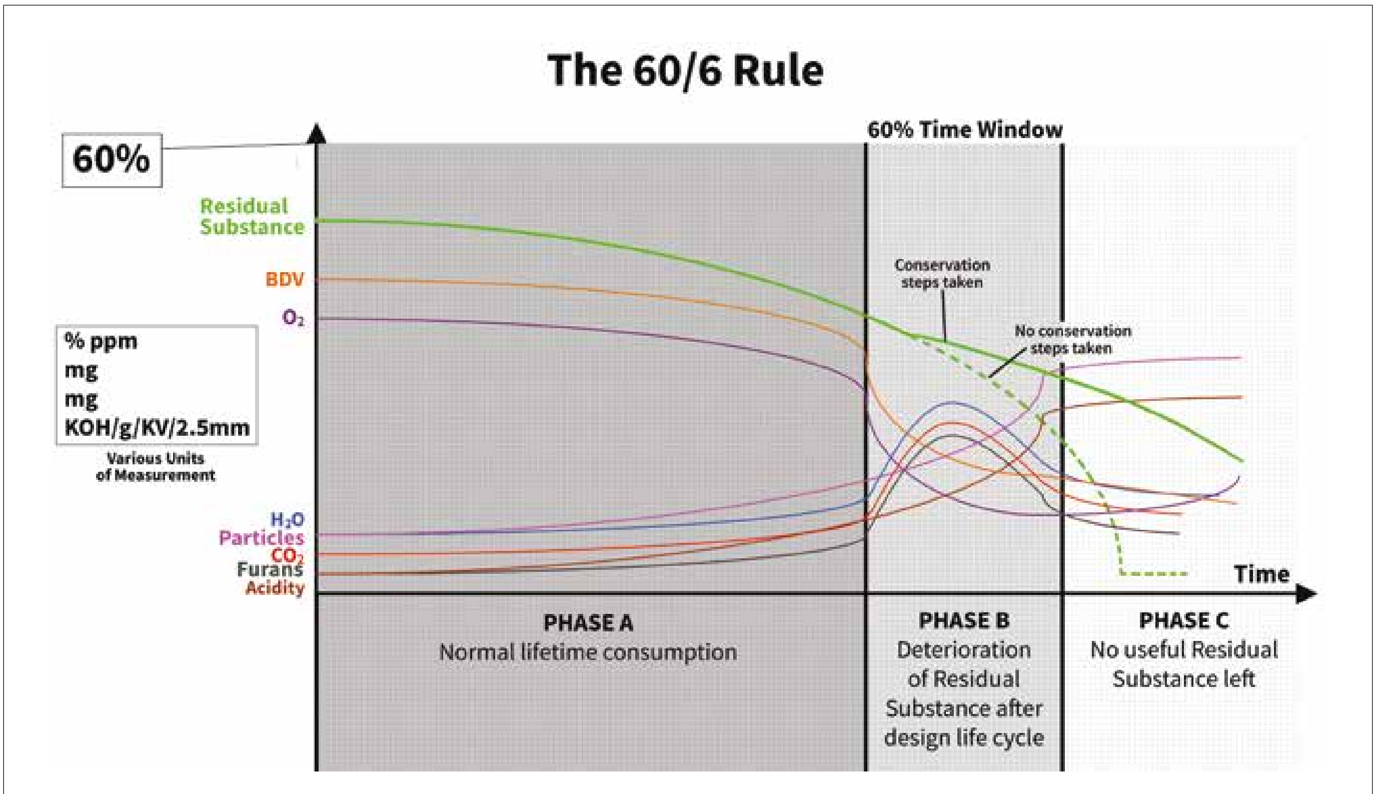

Figure 1.The nature of accelerated aging of power transformers with and without conservation measures

of the block. Type 3 failures are especially dangerous when they affect weakened assets, which cause a cascade of outages to other units in the block.

3. Reasons for mapping

All transformers are exposed to various risks. They age over time, causing premature failure. Their poor design can create functional weaknesses, which are only detected when operating over time. Random weather or grid-related risks can cause a complete transformer block shutdown. The mapping process described in this article is used to identify the risk to which a transformer block is exposed and what actions are needed to counteract the negative impact they have on performance. The process also considers the objectives of the plant owner, which may include the timing of plant shutdown or operating extensions, financial or safety goals. If not maintained properly, the original financial justification of the transformer and functional block in which it operates may not be reached. The final outcome of the mapping process is to provide multiple options that the plant owner can select based on an acceptable level of risk and required economic commitment.

4. The mapping process

The mapping process consists of eight steps. Each step builds on the next, resulting in the evaluation of different long-term replacement, remediation, and conservation actions that can be taken to reduce the risks of EOL. These action plans identify their associated costs and risks to enable the transformer block operator to select the actions best suited to meet the objectives of the plant.

The steps in the mapping process will be described using the following scenario:

5. Scenario description - A case study

In order to ensure that the transformers in a combined heat and power plant (CHP) would operate until its planned shutdown in six years, a preservation plan was developed for the plant. The initial phase of this plan was to regenerate insulating fluid for high-voltage, start-up, and station supply transformers. One year after the start of the preservation plan, the second phase of conditioning and conservation actions to one of the generation step-up units (GSU) began when a transportable conditioning unit was installed. In the third year of the conservation process, a second transportable conditioning unit was installed to further augment the conditioning of a second GSU transformer.

The mapping process consists of eight steps; each step builds on the next, resulting in the evaluation of different long-term replacement, remediation, and conservation actions that can be taken to reduce the risks of EOL

The data being collected from online gas monitoring systems over the first three years of the lifetime extension program, provided a significant amount of baseline information on the trend of RS. The analysis of this data raised the possibility of a longer lifetime extension. Because of this, it was decided to augment the assessment of critical assets in the plant. The scope was changed to include the evaluation of three scenarios where the cost and risks of a longer operating period would be evaluated. The three scenarios would allow the plant owner to compare the different alternatives so that he could determine whether a further ten-year extension was feasible and, if so, which course of action would be optimal. The motivation for this broader scope was to determine if the plant could continue to generate power and heat production revenues at a reasonable cost without incurring significant operating risks.

The mapping steps to accomplish this broader assessment of the CHP are as follows:

5.1. Mapping step 1: Statement of objectives

Identify the life extension options available to the CHP transformer block to ensure safe and reliable operation until a scheduled extended plant shutdown in 12 years. Provide the asset owner a complete risk/reward assessment of the proposed options.

5.2. Mapping step 2: Data collection and documentation

A complete history of the following data should be available and must include:

a. Dissolved Gas Analysis (DGA) - The collection of historical data on the types and changing levels of certain gases is a critical phase of the mapping process.

b. Oil condition measures, including oil acidity, interfacial tension (IFT), breakdown voltage (BDV), furan content, and inhibitor content.

c. Data regarding maintenance and failures must also be collected.

A key objective of this stage of the mapping process is to begin to understand the interactions of the aging accelerators and their influence on the aging process, as indicated in Fig 2.

5.3. Mapping step 3: Data analysis

1. The DGA analysis at this stage provides the data from which transformer condition diagnostics and risks are identified.

2. Measuring oil's aging impact on power transformers indicates the acceleration of the aging rate and the actions needed for its amelioration.

3. Maintenance history and data can show when and how mechanical anomalies occurred and record the mechanical design of replaced parts such as cooling systems and on load tap changer (OLTC)

Table 1 shows the number and function of the ten transformers in the CHP and their EOL assessment. The EOL assessment is also a complex procedure that includes the analysis of important indicators of O_2 consumption, the level and

The purpose of transformer mapping is to estimate the remaining lifetime, the potential for lifetime extension, and to assess investments as well as long-term preservation plans

types of furans, and the rate of decline of oil quality.

The data gathered in Step 2 is used to develop an understanding of the potential areas of risk and the possible replacement, remediation, and conservation strategies needed to extend the life of this CHP transformer block by another ten years.

Each transformer's aging condition was assessed based on a number of factors derived from continuous gas monitoring and indicator trends. Data collected from the transformer provide clues to its operating (service) condition. If high rates of gassing are found, for example, they may suggest hotspots due to poor cooling, which then leads to accelerated aging. High oxygen consumption may also indicate high rates of cellulose degradation due to high oil acidity. The expert assessment of these clues pinpoints the true service condition of the transformer. The appropriate remedial and conservation measures based on the transformer's actual service condition can then be implemented. The remaining lifespan estimates for each transformer were made, and each transformer was assigned to a remaining lifespan category, as shown above. Other factors such as load capacity, RS, and the possibility of advanced breakdown (PoAB) due to Type 2-3 risks were evaluated too. PoAB factors are explained in the previous article [1].

5.4. Mapping step 4: Risk assessment

- **Transformer GSU1**- This generator step-up transformer shows a slightly reduced substance ranking due to a number of factors. These include higher O_2 consumption and a high furan re-saturation rate, which indicates some accelerated aging. Treatments such as oil regeneration, remove furans from the insulating oil. In old, highly degraded transformers, furans trapped in the transformer's windings are not removed during such treatment. These furans reenter (re-saturate) the furan-free oil after regeneration. The rate of re-saturation can be quite high, where in one or two years, the furan content could be as high as it was before oil treatment. Some indications of high heat in some zones suggest the overloading of this transformer. Two different "high heat zones" can be found in a transformer. The temperature ranges in which they are found are different. A hotspot is a localized high heat zone with temperatures in the range of 300 – 600 °C. Temperature spikes to over 1000 °C can also occur. Hotspots are created by dirty or faulty electrical connections such as poor solder joints. They result in excessive gassing and high accelerated aging rates of the transformer. A hot zone has temperatures in the 150 to 300 °C range. These hot zones do not produce excessive gassing but do contribute to cellulose degradation. Hot zones are created

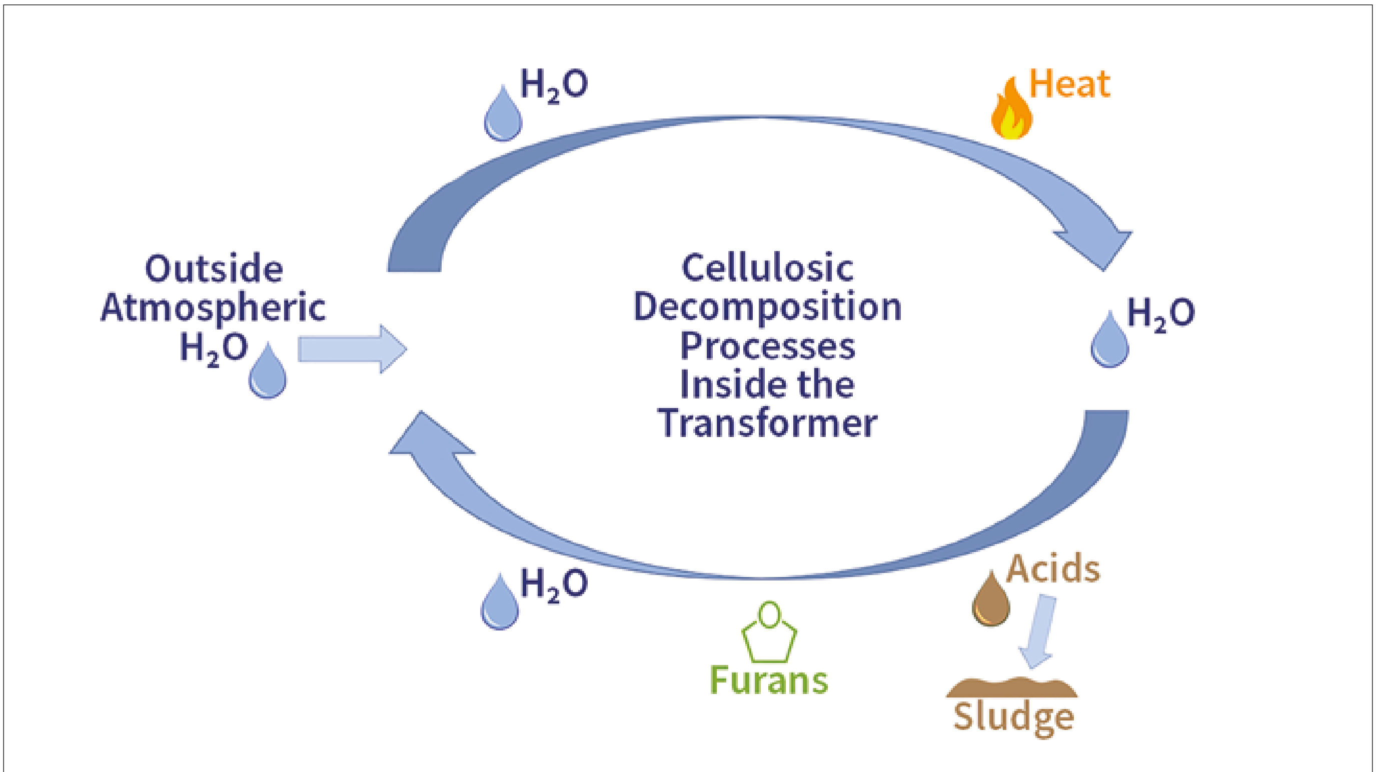

Figure 2. The cellulose decomposition process and its by-products in power transformers

Table 1. Ten transformers in the CHP

Transformer Type	ID	Aging Condition
GSU	GSU1	
	GSU2	
	GSUOLD1	
	GSUSpare1	
Auxilliary	AUX1	
	AUX2	
	AUX3	
	AUX4	
	AUX5	
	AUXB1	

Remaining Lifespan	Color
High	10+ years
Reduced	7-9 years
Greatly Reduced	5-6 years
Negligible	< 4 years

by poor oil circulation resulting in insufficient cooling. Oil acidity was good. It was determined that GSU1 would need to operate with simultaneous gas conditioning to slow the O_2 aging process. **Estimated remaining lifetime is four years.**

If, for example, high rates of gassing are found, they may suggest hotspots due to poor cooling, which then leads to accelerated aging

- **Transformer GSU2-** This generator step-up unit is in slightly better condition than GSU1. While RS is in the same range, a leak in a diverter switch shows acetylene in the system accompanied by a partial discharge. As is recommended for GSU1, GSU2 should be operated with the shared simultaneous gas conditioning unit. The **estimated remaining lifetime is greater than five years.**

- **Transformer GSUOLD1-** This generator step-up (GSU) transformer is in a precarious condition. All EOL factors were so low, indicating RS was non-existent. It can be used as a backup only under controlled conditions. **Estimated remaining lifetime is less than two years.**

- **Transformer GSUSPARE1-** This transformer was acquired from a peak-load gas-fired power station years ago. It is in excellent condition, despite being 15 years old. It was only in operation for approximately two years. Available data are not reliable as gas samples were taken while the transformer was not operating. Inspection of its bushings shows some capacitance deviations, which creates a fire risk. If re-testing confirms that the capacitive deviations remain and TANδ testing shows voltage leakage, it is recommended that the bushings be replaced. **Estimated remaining lifetime is over ten years.**

- **Auxiliary Transformers AUX1-** AUXB11- AUX 1 and 2 show some problems caused by defective tap selectors and leaky diverter switches, which cause high C_2H_2 levels. AUX3, AUX4, AUX5, and AUXB11 showed inconsistent readings of decreased moisture with higher BDV. This could be due to a lack of data reported on these units. Estimated remaining lifetimes for AUX1, AUX2, and AUX3 are approximately five years. **Estimated remaining lifetimes for the remaining auxiliaries are over five years.**

5.5. Mapping step 5: Classification of the units based on priority-of-importance criteria

The key transformers in the CHP are the GSUs: GSU1 and GSU2. The redundant older GSUOLD1 has the greatest probability of not reaching the extended 10-year operating limit. Permanent deployment of the existing conditioning units will reduce the Type 1 risk of premature failure of GSUOLD1 if needed for backup, but the risk cannot be eliminated completely. The redundancy and excellent functionality of GSUSPARE1 also reduce operational risk for the GSU cohort of transformers. The acquisition of new GSUs would almost guarantee to reach the 10-year extension but may introduce Type 2 risks, including financial risks in resale or deployment at the closing of the CHP.

The auxiliary transformers are a riskier cohort but have less impact on the operation of the CHP. The redundancy in this cohort is sufficient to minimize most risks to the entire plant. The connection of AUX1 to an external power source will further reduce the risk of losing revenue because of a decrease in the generating capacity of the plant due to premature failure.

5.6. Mapping step 6: Preventative and conservation measures

The scenarios defined below are intended to reveal the different risks that may arise when replacement, remediation, and conservation measures are taken.

Different investment scenarios are made that address and neutralize different types of risks associated with transformers in order to adjust to the client's budget

- Scenario 1 - No procurement of new transformers and no access to reserve transformers for redundancy. Possibility of loss of third-party grid transformer near the CHP. This scenario is exposed to high Type 3 risk with an extensive or total breakdown of the plant due to the lack of backup of the GSU transformers in the event of a third-party grid transformer failure. In addition, a failure of one of the GSU's would reduce revenue generation from power production by 50 %, as illustrated in scenario 1 (Table 2). Heat generation revenues may also be lost.

- Scenario 2 - Invest in the three conservation and conditioning systems and replace old GSU1 with a newer reserve transformer (150 MVA/ KV 110/10). This scenario provides backup for the GSUs and spares for start-up and station supply auxiliary transformers. Along with the procurement of more preservation and conditioning units for the existing auxiliary transformers, Type 1 risk from their accelerated aging can be reduced so that the required 10-year extension of an operating lifetime can be achieved. The switch of the older GSU1 to a newer reserve will reduce Type 1 risk. Acquire new backup auxiliary transformers (3 x 30 MVA 10/6 KV) for start-up and station supply for redundancy. This increases Type 2 risk, which will decline over time. Also, the addition of a connection to an external grid transformer to allow supply from outside the block will reduce Type 3 risk in the case of a random risk event. This scenario is exposed to some Type 2 and 3 risks.

- Scenario 3 - Switch out GSU1 with a newly acquired GSU (150 MVA / KV 110 / 10). Switch out GSU2 with GSUSPARE1. GSU2 can be used as a backup. Acquire three backup auxiliary units (3 x 30 MVA 10 / 6 KV). GSU1 and GSU2 can be backup GSU transformers for the new GSU and GSUSPARE1, which become the operating GSUs for the plant. Acquire three preservation and conditioning units to be rotated amongst the six operating auxiliary units. Replace defective switches and bushings. This scenario is exposed to similar levels of Type 2 and 3 risks. In addition, there is some financial risk created in the event the GSU is not sold or recommissioned at the end of the ten-year extension.

5.7. Mapping step 7: Scenario cost estimates and risk exposure

The costs and benefits for each option are summarized in Table 2.

5.8. Mapping step 8: Long-term preservation plan

Based on the economic analysis and associated risks of each of these scenarios, scenario 1 can be rejected outright as the benefits are offset by the level of risk in the event any one of the key assets fails. It is estimated that the loss of energy production from this plant could cost up to €200,000 per day. With a lead time of 18 months to receive a replacement transformer, this daily loss of revenue would continue to increase. As this is a CHP operation, heating revenues would also be lost during the winter months.

If scenario 2 is selected as the long-term approach to extending the life of the CHP, both technical and economic risks will be low. The backup units for the GSU and auxiliary transformer will minimize much of the risk in the event of a short-circuit of either a third-party grid transformer or an auxiliary start-up or supply unit. The conditioning and monitoring units will ensure RS is con-

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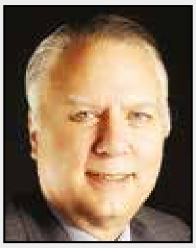

Charles Cole serves as Vice President of Polywater's International Division where he is responsible for the development of new global markets. Cole collaborates with partners, working side-by-side to develop products that help them address field challenges and increase their abilities to maximize the life of critical assets. In this role, he has focused on developing markets in Asia, Central and South America, and Oceania by overseeing the growth of Polywater's global network of subsidiaries and local partners. His current focus has been on the increasing demand for intermediate repair solutions in India by expanding our on-the-ground presence. Additionally, he has steered the start-up of light manufacturing facilities to cover South American markets and established new rep offices in key markets.

Table 2. Scenario cost estimates and risk exposure

Scenario 1

Description	Cost (€)	Comments
Transformer conditioning units	175,000	New transformer conditioning units
Transformer maintenance	75,000	Older units require more maintenance
Total Investment	**250,000**	
Risk		**Comments**
Type 1	Moderate	Possible EOL of older units
Type 2	None	No new transformers installed
Type 3	High	No back-up of GSU

Scenario 2

Description	Cost (€)	Comments
Transformer conditioning units	250,000	Acquire three transformer conditioning units
Auxilary Transformers	1,500,000	Acquire three auxilary transformers
Transformer maintenance	25,000	Reduced due to acquisition of new auxilary transformers
Total Investment	**1,775,000**	
Risk		**Comments**
Type 1	Negligible	Transformer Conditioning units reduce EOL condition
Type 2	Low	New auxilary transformers have sufficient back-up
Type 3	Low	Sufficient reserve units and connection to grid
Financial	None	NA

Scenario 3

Description	Cost (€)	Comments
Transformer conditioning units	500,000	Acquire three transformer conditioning units
GSU Transformers	2,000,000	Acquistion of one GSU unit
Auxilary Transformers	1,500,000	Acquistion of three auxilary units
Transformers Maintenance	0	No maintenance due to new transformers
Total Investment	**4,000,000**	
Risk		**Comments**
Type 1	Negligible	New transformers reduce accelerated aging issues
Type 2	Moderate	May be design/quality issues with new GSU/aux.
Type 3	Low	Sufficient reserve units and connection to grid
Financial	Moderate	Possible delay in recommissioning of new GSU

served to reduce the risk of accelerated aging in the older units.

If scenario 3 is selected, Type 2 risks will increase, making the overall risk profile slightly higher than scenario 2's profile. Scenario 3 benefits come at a much higher investment in new equipment than scenario 2. The higher investment also generates a financial risk if there is a significant delay in selling or recommissioning the new GSUs after the ten-year extension period.

Summary

This article has shown how the mapping process can be used to quantify the technical, economic, and financial risk of transformer populations. The causes of transformer failure, e.g., poor design / workmanship, random external phenomena, and accelerated aging, determine the level of uncertainty to which a transformer block is exposed. Based on the level of uncertainty and where this uncertainty is the greatest, appropriate remediation and preservation / conservation measures can be developed to ensure both technical and economic objectives are met.

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[1] Daemisch, Georg, *Mapping transformer populations – A key to optimize maintenance processes in order to minimize risks and cost*, Transformers Magazine, Vol 7, No.1, 2020