Development of a Cost-Benefit and Risk-Based Maintenance Model for Power Transformers

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Dedicatoria

A mi madre, a mi padre. A mis hermanos. A mis amigos. A Julián, siempre a Julián.

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Resumen

Esta tesis presenta una aproximación diferente para la evaluación de mantenimiento en transformadores de potencia. A partir de la evolución de condición de salud de un transformador de potencia, y los conceptos de costo, riesgo y beneficio asociados a ésta, se puede predecir cuando la aplicación de mantenimiento es ideal para dicho transformador. Para esto, primero se hace uso de información histórica de carga y de pruebas de 5 transformadores de potencia de muestra para obtener su evolución de condición de salud y tasa de falla en el tiempo. Para evaluar los efectos de mantenimiento, se aplica los esquemas de mantenimiento propuestos previamente en la bibliografía. Finalmente, se plantean las condiciones para evaluar el modelo de riesgo y el modelo de costo-beneficio, por medio de la evolución de condición de salud y el plan de remuneración vigente para los transformadores de potencia en Colombia. De este modelo se obtendrá los momentos en los cuales aplicar mantenimiento en el transformador le representan mayor beneficio al operador.

Palabras clave: transformador de potencia, condición de salud, evaluación de riesgo, probabilidad de falla, evaluación de mantenimiento.

Abstract

This thesis presents a different approach for maintenance evaluation in power transformers. From the evolution of the health condition of a power transformer, and the concepts of cost, risk and benefit associated with it, it can be predicted when the maintenance application is ideal for such transformer. For this, first load and tests historical data of 5 sample power transformers are used to obtain their evolution of health condition and failure rate in time. To evaluate the maintenance effects, maintenance schemes previously proposed in the literature are applied. Finally, the conditions for evaluating the risk model and the cost-benefit model are proposed, through the evolution of health condition and the current remuneration plan for power transformers in Colombia. From this model it will be obtained the moments in which applying maintenance in the transformer represent the greatest benefit to the operator.

Keywords: power transformer, health index, risk evaluation, probability of failure, maintenance evaluation.

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Symbol	Term	SI Unit	Definition
θ_A	Ambient temperature	$^{\circ}C$	The temperature of the medium in which the asset heat is dissipated (air, water, or earth)
θ_{HS}	Hot-spot temperature	$^{\circ}C$	Temperature measured in the winding hottest-spot
θ_{TO}	Top-oil temperature	$^{\circ}C$	Temperature measured in the top part of the oil
U	Rated voltage	kV	Transformer rated voltage
S	Rated power	MVA	Transformer rated power

Abbreviations

Abbreviation	Term
UPME	Unidad de Planeación Minero Energética
Expansion plan 2016-2030	Plan de expansión de referencia Generación-Transmisión 2016-2030
STN	Sistema de Transmisión Nacional
STR	Sistema de Transmisión Regional
CREG	Comisión de Regulación de Energía y Gas
ENEL - Codensa	ENEL - Codensa S.A ESP
SAMP	Strategic Asset Management Plan
AM	Asset management
UC	Cost per constructive unit
SAIDI	System average interruption duration index [h]
SAIFI	System average interruption frequency index [No. int]
ENS	Energy not supplied [kWh]
MTTF	Mean time to failure [h]
MMTR	Mean time to repair [h]
HI	Health index or health condition
$\lambda(HI)$	Failure rate
P_{10}	10^{th} percentile

Abbreviation	**Term**
P_{50}	50^{th} percentile or median
P_{90}	90^{th} percentile
POF	Probability of failure
NIL	Normal insulation life [h]
DGA	Dissolved gas analysis
OLTC	On-line tap changer
C_2H_2	Acetylene [ppm]
C_2H_4	Ethylene [ppm]
CH_4	Methane [ppm]
C_2H_6	Ethane [ppm]
H_2	Hydrogen [ppm]
CO	Carbon monoxide [ppm]
CO_2	Carbon dioxide [ppm]
O	Oxygen [ppm]
N	Nitrogen [ppm]
$TDCG$	Total sum of dissolved combustible gases [ppm]
DP	Degree of polymerization
F_{AA}	Accelerated aging factor
L_F	Loss of life
$2-FAL$	Furan: 2-furfural
$2-FOL$	Furan: 2-Furfurol
$5-HMF$	Furan: 5-Hyroxymethyl-2-furfural
$5-MEF$	Furan: 5-Methyl-2-furfural
$2-ACF$	Furan: 2-Acetylfuran
C_{ins}	Installation cost
C_{inv}	Investment cost
C_M	Maintenance cost
h_{OS}	Hours out of service
P_{TR}	Transformer power
CRO	Regulation price

1. Introduction

Among the different economic sectors and companies, there is always interest in developing plans and strategies that allow balancing performance with costs. Inside an electrical system, operators invest in assets for providing a good performance, then, it is necessary to use decision tools.

Assets represent a high investment for any system and their deterioration in an electrical system implies disadvantages like: interruptions, overcharges, compensation costs, among others. When it comes to critical assets, their appropriate use and management becomes a matter of study, depending on the principles of Asset Management (AM) and electric regulation of the country [1]. That is why in this chapter, it is important to discuss about the aspects, problems and regulation that affect the management of power transformers in an electrical system [2].

1.1. About power transformers

Electrical systems are composed of hundreds of different assets and divided into several branches. However, not all assets are managed in the same way. In the last years, the power transformer has become a highly studied asset inside the AM of electrical systems. Since the beginning, the transformer is one of the most important assets inside a system, because it is needed in almost all stages of the electrical system (Generation, Transmission and Distribution) and represents a high investment for the operator.

There are several types of transformers and each one has a different function like: current transformer, voltage transformer, power transformer and distribution transformer. However, the power transformer is the object of study in this research.

There are two main related factors that affect these assets mainly:

- The first one is overload. When the system and the power transformer itself is overloaded, there is a risk of accelerated aging. This implies a higher risk of failure and changes in the reliability of the system.

- The second one is aging. Regardless of the load supported by the transformer, it ages constantly. For assets like current and voltage type, it depends on the load of the substation; and in distribution transformers, which are dry-type, it represents a problem, but taclked differently.

For the power transformer, this relation between load and aging represents a big concern due to the possible accelerated aging in the insulating paper [3]. When the insulating paper has lost its insulating properties, a replacement is necessary.

Inside the power transformer, there are several elements and some of them are considered more critical for its functioning. In some references, they are separated in different systems divided into two categories: internal systems and complementary/auxiliary systems. The internal systems are composed of: ferromagnetic core, windings, fastening and insulation systems. Some of the complementary systems are: tap changers, bushings, measure and protection systems. However, in other references that study the aging of the transformer through Health Condition, the most important parts are: windings, core, tank and external parts like bushings, and measure and protection systems.

The study of these parts through analysis and tests is the start for evaluating the health condition of the transformer. Different models will be used in the next chapters in order to evaluate their health condition and propose a maintenance model.

1.2. Background and justification

Within an electrical system, there is a large amount of assets. Each of these assets has its own evolution of health condition over time with its associated reliability. The condition of an asset refers to the state of reliability it has over its useful life. This condition evolves from a reliable state, after the commissioning, to an unreliable state, when a replacement is necessary [4] [5] [6].

Due to the investment and operational costs related to the power transformer, it is one of the most critical assets. Along its operation, this asset can present accelerated aging caused by different electrical, thermal and mechanical stresses. Asset management presents a variety of strategies and tools in order to improve the performance of an asset based on the benefits to the company and the user. Maintenance is a fundamental strategy to sustain and manage the performance of this asset.

In the case of Colombia, the UPME's Expansion Plan 2016-2030 [7] contemplates several expansion projects for the selected period. According to [7], overload and low voltages, in different areas of the system, are some of the identified problems that represent a risk for the Colombian electrical system. These problems are mainly located in remote areas where the system is less reliable.

On the one hand, the overload of power transformers is considerably dangerous. If this asset fails, it can cause overloading in other assets, substations and, therefore, possible contingencies, especially in STN and STR connections. These possible contingencies represent an accelerated aging in the affected assets.

On the other hand, low voltages are associated with generation units out of service connected to a single transformer, which can cause loss of demand and imbalance of the dispatch. In some parts of the Colombian electrical system, it is common to find assets loaded 110%, thus most of the projects planned by the UPME in service are related to the replacement and addition of assets. This situation is common in power transformers located in remote substations. Through these projects, it is expected to move from the overload condition and low voltages to an adequate performance status at the end of the period. Therefore, it is observed that the trend in the Expansion Plan is to reduce the service outputs related to the power transformers failures in the Colombian electrical system.

Expansion Plan 2016-2030 also carries out an economic evaluation that takes into account the costs and benefits obtained from the expansion projects. These benefits are measured in improvement of operator reliability indices and reduction of costs by compensation. Expansion projects are represented in constructive units (UCs) [7], which translate into a component of reliability and cost associated with these projects of expansion.

In this sense, within the long-term considerations of the STN, there are three main actions: Planning, Execution, and Operation and Maintenance. These considerations are compiled in the CREG Resolution 011 of 2009 [8] and CREG Resolution 097 of 2008 [9] for the economic evaluation of the operation and maintenance of the assets of STR and STN [7].

Additionally, CREG Resolution 015 of 2018 [10] changes the scheme for remuneration plans in assets belonging to the electrical systems. This resolution is based on the set of standards ISO 55000 [11]. In this resolution, the CREG demands operators to develop and implement an asset management system.

Taking into account these considerations, a power transformer is one of the most important assets of the system, and is the one that represents a higher risk for the operator, and also for the electrical system. Consequently, its planning in operation and maintenance has great importance in the long-term for the Colombian electrical system and is subject of study in this research.

1.3. Problem statement

Analyzing the whole panorama around electrical assets currently, the power transformer is identified as a vital asset inside the electrical system. In the Colombian case, in recent years there has been a trend in overloading and low tensions. These problems are also associated with power transformers. Consequently, expansion projects within the Expansion Plan 2016-2030 by the UPME are focused on mitigating these problems from the point of view of assets reliability and the associated ENS. In the long-term, organizations such as the UPME and network operators also associate expansion and operation and maintenance activities with a cost-benefit ratio that represents an improvement in reliability indices.

Within AM, there are several strategies that are intended to improve the condition and therefore the useful life of the asset. Among these, maintenance is one of the most used strategies. Though, it is essential to ask: which is the best maintenance action associated with risk? What is the profit between Cost and Benefit?, and is it feasible to develop a scheme that comprises the Cost-Benefit component? For answering these questions, it is necessary to adjust a new model of maintenance based on the traditional schemes and taking into account the risk associated with the condition of the asset, the balance in reliability improvement and the investment cost. Therefore, to obtain a better performance applied to the Colombian case, it is a necessary to propose a maintenance strategy for power transformers that includes both, cost-benefit and risk constraints, from the point of view of the network operator.

1.4. Objectives

1.4.1. Main objective

To develop a maintenance model for power transformers that includes the cost-benefit relationship and the risk associated with the actions of the model.

1.4.2. Specific objectives

- Perform a review of currently available maintenance schemes and their respective reliability models.
- Perform a failure risk model for the maintenance model.
- Develop a new maintenance model and a cost-benefit model.

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2. Health condition in power transformers

Summary

In this chapter, health condition model for power transformers is presented. For this, all indices considered for this research are presented with their respective models and weights. Later, health condition simulation for all sample transformers is presented along with their reliability component.

Introduction

When it comes to manage power transformers, there are several studies that propose different power transformer condition assessment and life-management techniques [1]. In order to evaluate the impact of a maintenance, it is necessary to establish a model of health condition. Health condition is one of the most used in this kind of assets. For this purpose, there are different indices obtained from inspection and tests applied to the transformer, which can be measured in general form or in a specific part of the asset [1] [2]. The condition can be associated with a failure rate from an extrapolation with previous data [2]. Health condition and failure rate are necessary for evaluating maintenance in the power transformer.

2.1. Monitoring through health condition

When assets are manufactured, there is a given period of time in which their functioning is guaranteed under rated conditions. In the case of a transformer, specifically a power transformer, this time of guaranty is given by the NIL [3], which depends on the insulation life.

The insulation life refers to the condition of the insulating paper in the power transformer. When this paper has lost all its properties, it is considered as the end-of-life of the transformer. This insulation life will be explained in Chapter 4 from the concept of polymerization degree and furans content described in Section 2.2. When the asset is aging quickly, a higher failure rate is expected.

Health condition is one of the most used models for analyzing the condition of an asset. The estimation of this condition has been widely studied for power transformers. It consists in evaluating health indices based on tests data through a weighted sum in order to obtain a single index. Although there is no consensus about how many indices are necessary or the importance of each one. The study in [4] presents an evolution of weights for obtaining health condition in a power transformer.

Generally, there are some tests that are not regularly performed in the transformer, hence there is a lack of information when it comes to analyzing the evolution of indices related to these tests. However, many of the summarized studies use real data to develop their research [4]. Because of this lack of data, most of studies focuses only in DGA, furans content and age indices. This research proposes implementing HI monitoring with *9* different health indices that are presented in Section 2.2. Several of these indices have been studied before, such as DGA, furans content, aging factor, load and saturation over water [5].

For this model, the data used were provided by ENEL-Codensa, which is an operator, whose most of its market is located in Cundinamarca, Colombia, specially in Bogotá. ENEL-Codensa belongs to the Grupo de Energía de Bogotá and is the largest electricity utility in the country.

The information provided by ENEL-Codensa corresponds to a project developed together with Universidad Nacional de Colombia. This project consisted in implementing an Asset management system for evaluating ENEL-Codensa assets. In this AM system, shunt bank capacitors, power transformers, switch-gear cells and other assets were managed.

In most of the cases, such as dielectric strength or interfacial tension indices, statistical data of different transformers were used to observe their evolution in time. Growing rates were found for some health indices according to their own load. In other cases, no growing rate was found, but a constant behavior in time instead.

2.2. Health indices

There are several health indices that can be considered in order to estimate HI in a power transformer. According to their importance, weight can be approximated. Some of these indices have more studies and proposed models as background, although, some tests such as bushing condition, infra-red or DGA of OLTC are not common practices for the maintenance operators [6], thus, they are not considered for estimating HI. Table 2.1 presents some of the most known tests that can be applied to power transformers for analyzing health condition.

Table 2.1.: Indices considered from some studies [1].

Index	
DGA	Load history
Power factor	Infra-red
Oil quality	Overall condition
Furan or age	Turns ratio
Leakage reactance	Winding resistance
Core-to-ground	Bushing condition
Main tank corrosion	Cooling equipment
Oil tank corrosion	Foundation
Grounding	Gaskets, seals
Connectors	Oil leaks
Oil level	DGA of OLTC
OLTC oil quality	Overall OLTC condition

The indices considered for this research are:

- **Dissolved gas analysis index (DGA):**

  It is one of the most common used indices, since it has been widely studied [5] [7]. It is evaluated through the sum of dissolved combustible gases ($TDCG$) in oil according to Eq. (2.1), where C_2H_2, C_2H_4, H_2, CH_4, C_2H_6, CO are the concentrations of acetylene, ethylene, hydrogen, methane, ethane and carbon monoxide, respectively.

  There are other gases produced inside the transformer, such as N and O. These gases are not taken into account because they are incombustible. Additionally, the IEEE Std C57.104 [8] proposes the initial values of these dissolved gases, and some limits for their evaluation.

  $$TDCG = C_2H_2 + C_2H_4 + H_2 + CH_4 + C_2H_6 + CO \tag{2.1}$$

  From the data obtained by gases chromatography, it is also possible to establish an approximation to the fault type that might occur in the transformer depending on the gases concentrations. This methodology was proposed by Duval and consisted in finding some specific ratios from key gases in order and the correlation with historical fault data [9]. These gases are CH_4, C_2H_4 and C_2H_2.

Currently, there is a new methodology for finding the fault type in transformers, which consists in a pentagon with 5 key gases. Depending on the ratios of these key gases, this methodology proposes different types of fault, some of them which were not considered in the triangle. This new pentagon proposes different fault types depending on 5 gases concentrations: H_2, C_2H_6, CH_6, C_2H_4, and C_2H_2. The description of these fault types is presented in Table 2.2.

Table 2.2.: Fault types by Duval pentagon [10].

Abbreviation	Fault Type
F_{PD}	Partial discharge
F_{T1}	Thermal fault $< 300°C$
F_{T2}	Thermal fault $300 - 700°C$
F_{T3}	Thermal fault$> 700°C$
F_{D1}	Low energy discharge (Sparking)
F_{D1}	High energy discharge (Arcing)
F_{S-120}	Stray gassing of oil at $120°C$
F_{S-200}	Stray gassing of oil at $200°C$
F_O	Overheating $< 250°C$
F_C	Possible carbonization of paper

- **Dielectric strength index (DS):**

  This index refers to the monitoring of dielectric strength in the transformer oil. It belongs to the physical-chemical tests performed in the transformer when a scheduled maintenance is performed. The dielectric strength index can also be affected by breakdowns inside the tank, moisture and other compounds in the insulating oil [11].

  Dielectric strength measures the voltage necessary to produce spark between two electrodes immersed in a sample oil. These electrodes are usually separated by a gap of 1 mm, but other standards consider a gap of 2 mm. There are established limits for this index which vary depending on the standard and on the transformer rated voltage [12].

Limits for evaluating this index depend on the power transformer maximum voltage and are based on [1].

- **Interfacial tension index (IFT):**

  The interfacial tension quantifies the balance in forces, when there are different mixed phases. In this case, it refers to the oil interfacial tension relative to other compounds and contamination inside the oil. These compounds can be dissolved gases, furans or water particles produced inside the tank. A considerable decrease of interfacial tension generally represents a growth of products dissolved in the paper. When the transformer is aged, this index tends to decrease [13].

  The limits for evaluating this index are divided according to the maximum voltage in the power transformer [1].

- **Acid number index (AN):**

  The acid number index measures the acidity of the oil in the tank. This number represents the necessary mass of potassium hydroxide (KOH) in milligrams for neutralizing acid in every gram of the oil [13] [14]. Generally, this number tends to increase due to external conditions along the aging of the transformer. Otherwise, it tends to remain constant in time.

  Usually, if this number increases, it can be an indicator of higher oxygen production inside the oil, or even filtration of water. The study in [14] presents suggested values for this index, however, the limits for evaluating this index depend on the transformer voltage [1].

- **Water content index (H_2O):**

  In an oil-immersed power transformer, water content affects directly both insulating parts: paper and oil. Water content depends on the temperature inside the tank or top-oil temperature (Θ_{TO}), due to the decomposition of hydrocarbons [15]. However, the moisture inside the tank tends to remain constant as the particles of water move from the paper to the oil following Θ_{TO}, but staying the same amount. This amount of water particles may increase under external circumstances, which are not taken into account in this research. This index is evaluated according to the limits presented in [1].

- **Furans content index (Fur):**

  Furans content index is one of the most important indices and has a higher weight than others because, since it is used for evaluating HI, but it is also directly related to the remaining life of the transformer [16]. Furans are compounds derived from the insulating paper and are dissolved in the oil. When this paper has lost all its insulating properties, it is considered that the transformer is at the end of its useful life. These compounds are: 2-furfural ($2-FAL$), 2-Furfurol ($2-FOL$), 5-Hyroxymethyl-2-furfural ($5-HMF$), 5-Methyl-2-furfural ($5-MEF$), and 2-Acetylfuran ($2-ACF$) [17].

For estimating the condition of insulating paper, the degree of polymerization is used. The degree of polymerization (DP) is the average number of glucose rings in the insulating paper. An average transformer is expected to have a DP of 1100 at the beginning of its life and this value decreases along its operation. When a DP of 200 is measured, it is considered an extremely aged transformer [18]. The DP is generally estimated through the most representative and stable furan, $(2-FAL)$, according to Eq. (2.2) [19]. However, if the paper is thermally treated, then the DP is calculated through the sum of all furans.

$$DP = \frac{log_{10}(2 - FAL \times 0.88) - 4,51}{-0.0035} \tag{2.2}$$

When oil is filtered, due to a maintenance action, furans content measure is not consistent with previous measures. However, deterioration in paper is irreversible, therefore, it is expected to increase in time. For this reason, furans index can be approximated through the years in operation, as shown in Eq. (2.3) [5], where: F is the amount of furans and t_{years} is the operation time in years.

$$log(F) = -1.8308 + 0.0578 \times t_{years} \tag{2.3}$$

Since, the furans content is related to the remaining life of the transformer, it is considered that the transformer is totally degraded when furans index achieves its poorest condition. Yet, HI can be different from 1 when the asset reaches the end of its life. Limits for evaluating this index are based on [1].

- **Load factor (Load):**

  Load factor has also been implemented in different studies for HI calculation [5] [20]. In some cases, the impact of overload monthly peaks are evaluated in the aging of the transformer. However, in this research, the load factor is evaluated through the amount of peaks that are evaluated in the loading factor F_L.

$$F_L = \frac{\sum_{i=0}^{4}(4-i) \times N_i}{\sum_{i=0}^{4} N_i} \tag{2.4}$$

  Equation (2.4) estimates F_L, where [1]:

  - N_0 is the amount of peaks under 0.6p.u., with $i = 0$
  - N_1 is the amount of peaks between 0.6p.u. and 1p.u., with $i = 1$
  - N_2 is the amount of peaks between 1p.u. and 1.3p.u., with $i = 2$
  - N_3 is the amount of peaks between 1.3p.u. and 1.5p.u., with $i = 3$
  - N_4 is the amount of peaks above 1.5p.u., with $i = 4$

- **Loss of life (L_{life}):**

  Finally, the loss of life of a transformer refers to the cumulative hours of aging of the transformer, depending on its aging factor. In some references, this index is related directly to the years in operation of the transformer [5], t_{years}). The aging of the power transformer is highly important for its health condition, and generally, used or associated to another health index. Load and operation conditions have an impact on the health condition of the transformer. Some references discuss about its aging through the electrical model of the transformer. With this model, it is possible to estimate hot-spot, θ_{HS}, and top-oil temperatures θ_{TO}, from the operating conditions of the transformer [3].

  In this research, this index is estimated by obtaining the aging factor, F_{AA}. For this purpose, θ_{TO} and θ_{HS} temperatures are calculated from Eq. (2.5) - Eq. (2.6) [5] [21], where $\Delta\theta_{TO}$ is the rise of top-oil temperature over ambient temperature and $\Delta\theta_{TO}$ is the rise of hot-spot temperature over oil temperature.

$$\theta_{TO} = \theta_A + \Delta\theta_{TO} \tag{2.5}$$

$$\theta_{HS} = \theta_A + \Delta\theta_{TO} + \Delta\theta_{HS} \tag{2.6}$$

  By solving these equations, the evolution in time of θ_{TO} and θ_{HS} is obtained according to the characteristic load. Then, the Arrhenius Law is applied to obtain: aging factor, F_{AA}, and loss of life, L_{life}, in hours, which are inversely proportional to NIL in hours. Commonly, for a power transformer in oil, this value is around 180.000 hours or 20 years according to IEEEC57.91 [3].

  The Law of Arrhenius is derived from the verification made by Dakin in [22]. The author developed a relationship between the temperature of the material and its degradation, which gave as a result an increase in temperature in the transformer. Therefore, by using the electrical-thermal model of the transformer and the Arrhenius Law, it is possible to obtain F_{AA} according to Eq. (2.7), where θ_{HS} is the winding hot-spot temperature in $°C$ [3] [5]. Evaluation of F_{AA} for all sample transformers according to the projected load is presented Appendix A.2.2.

$$F_{AA} = exp\left[\left(\frac{15.000}{383}\right)-\left(\frac{15.000}{\theta_{HS}+273}\right)\right] \tag{2.7}$$

Finally, F_{EQA} is the equivalent aging of the transformer, which is calculated in a period of time, generally 24 hours. It shows the real aging of the transformer in the time interval according to Eq. (2.8).

$$F_{EQA} = \frac{\sum F_{AA} \cdot \Delta t}{\Delta t} \tag{2.8}$$

With F_{EQA}, loss of life is calculated as seen in Eq. (2.9) [3] [23].

$$L_{life} = \frac{F_{EQA} \cdot t}{NIL} \tag{2.9}$$

- **Saturation over water index (%Sat):**

  The saturation index describes the proportion of water and oil inside the transformer. For analyzing this index, it is necessary to introduce the concept of solubility, as shown in Eq. (2.10), where W_c is the initial water content and S_0 is the solubility of water in oil.

$$\%Sat_{H2O} = \frac{W_c}{S_0} \tag{2.10}$$

  Solubility is the amount of dissolved water in oil at a given temperature, therefore, it depends on the temperature in the oil (θ_{TO}) [15]. This solubility can be determined by Eq. (2.11) [24] [25]. Limits to evaluate saturation are based on [24].

$$Log(S_0) = \frac{-1567}{\Theta_{TO}} + 7.0895 \tag{2.11}$$

2.2.1. Weights and limits

After describing the required indices in Section 2.2, it is necessary to determine the weight of each one of these indices. Since there is no agreement about the importance and weight of each index, or even the limits, most of these weights were based on references [4] [26], and on expertise opinion. Generally, DGA and Furans indices present the highest weights for evaluating power transformers. These weights are presented in Table 2.3 and the corresponding condition to each one of these r_i in Table 2.4. Finally, a weighted sum can be obtained according to Eq. (2.12).

$$HI = \frac{\sum_{i=1}^{n} \omega_i r_i}{\sum_{i=1}^{n} \omega_i} \tag{2.12}$$

Table 2.3.: Limits and weights for all indices

Index		Condition				
		Good	Acceptable	Poor	Very poor	Weight
Furans content [ppb]		$Fur \leq 0.1$	$0.1 < Fur \leq 0.25$	$0.25 < Fur \leq 0.5$	$Fur > 0.5$	10
DGA [ppm]		$TDCG < 720$	$720 \leq TDCG < 1920$	$1920 \leq TDCG < 4630$	$TDCG \geq 4630$	7
Dielectric strength [kV]	$U \leq 69kV$	$DS \geq 45$	$35 \leq DS < 45$	$30 \leq DS < 35$	$DS \leq 30$	3
	$69kV < U < 230kV$	$DS \geq 52$	$47 \leq DS < 52$	$35 \leq DS < 47$	$DS \leq 35$	
	$U \geq 230kV$	$DS \geq 60$	$50 \leq DS < 60$	$40 \leq DS < 50$	$DS \leq 40$	
Water content [ppm]	$U \leq 69kV$	$H2O \leq 30$	$30 < H2O \leq 35$	$35 < H2O \leq 40$	$H2O > 430$	2
	$69kV < U < 230kV$	$H2O \leq 20$	$20 < H2O \leq 25$	$25 < H2O \leq 30$	$H2O > 30$	
	$U \geq 230kV$	$H2O \leq 15$	$15 < H2O \leq 20$	$20 < H2O \leq 25$	$H2O > 25$	
Interfacial tension [mN/m]	$U \leq 69kV$	$IFT \geq 25$	$20 \leq IFT < 25$	$15 \leq IFT < 20$	$DS \leq 15$	5
	$69kV < U < 230kV$	$IFT \geq 30$	$23 \leq IFT < 30$	$18 \leq IFT < 23$	$DS \leq 18$	
	$U \geq 230kV$	$IFT \geq 32$	$25 \leq IFT < 32$	$20 \leq IFT < 25$	$DS \leq 20$	
Acid number	$U \leq 69kV$	$AN \leq 0.05$	$0.05 < AN \leq 0.1$	$0.1 < AN \leq 0.2$	$AN > 0.2$	2
	$69kV < U < 230kV$	$AN \leq 0.04$	$0.04 < AN \leq 0.1$	$0.1 < AN \leq 0.15$	$AN > 0.15$	
	$U \geq 230kV$	$AN \leq 0.03$	$0.03 < AN \leq 0.07$	$0.07 < AN \leq 0.1$	$AN > 0.1$	
Saturation over water [%]		$\%Sat \leq 0.1$	$0.1 < \%Sat \leq 0.25$	$0.25 < \%Sat \leq 0.5$	$\%Sat > 0.5$	2
Load factor		$F_L \geq 3.5$	$2.5 < F_L \leq 3.5$	$1 < F_L \leq 2$	$F_L < 1$	2
Loss of life [h]		$L_{life} \leq 45000$	$45000 < L_{life} \leq 90000$	$90000 < L_{life} \leq 135000$	$L_{life} > 180000$	2

Table 2.4.: Values of r_i evolution for every index

Index [r_i]	Condition			
	Good	Acceptable	Poor	Very poor
r_i	0-0.25	0.25-0.5	0.5-0.75	0.75-1

2.3. Reliability component

In Electrical Engineering, reliability is generally defined as “the ability of the system to perform under given conditions for a given time interval” [27]. Although reliability applies for a large amount of terms related to Power Quality, it focuses only on equipment outages and, consequently, on customer interruptions [28]. According to this, Availability is a subset of Reliability, and Reliability is a subset of Power Quality focused on interruptions.

Reliability indices of an operator are obtained from statistical data of the load conditions, components, and customers. Applied to a specific operator, its reliability indices may depend on the configuration of the substation and the function it develops. $SAIDI$ and $SAIFI$ are some these customer-based reliability indices. These indices are related to the amount of interruptions and the duration of these interruptions that the customer perceives, therefore, they give an idea of the service quality perceived by the user.

Since it is complicated to obtain wide operator information for estimating its reliability indices, for this research, reliability indices focused in one asset are evaluated. For the Colombian case and according to the current regulation [29], service quality is defined taking into account reliability indices such as maximum hours of unavailability and maximum percentage of ENS per asset. Therefore, applying actions for improving reliability indices improves service quality and reduces costs for the operator.

2.3.1. Failure rate and reliability

After obtaining the health condition of an asset (HI), it is possible to associate this condition to a failure rate based on statistical data. Some experts, such as Brown in [2], propose some key considerations for analyzing the aging of an asset:

- Probability of failure tends to increase.
- Maintenance costs tend to increase.
- The replacement of certain parts can be difficult to achieve.
- Old equipment may become technologically obsolete.

The last two considerations cannot be applied directly to this model, since it clearly depends on the criteria of the operator and owner of the power transformer. However, the first two considerations are necessary for the failure rate model. Indeed, an exponential function can be obtained with an initial condition C, as shown in Eq. (2.13), where the failure rate depends on the health condition score (HI) [5] and A, B, and C are calculated by interpolation from statistical data [2].

$$\lambda(HI) = Ae^{(B \cdot HI)} + C \tag{2.13}$$

Table 2.5.: Constants for calculating failure rate.

Asset	Constants		
	A	B	C
S $\leq$ 25 MVA	0.0156	2.2478	-0.0081
S $>$ 25 MVA	0.0096	2.5618	-0.0046

After obtaining the failure rate of the asset, reliability (R) and probability of failure (POF) can be found according to Eq. (2.14) and Eq. (2.15).

$$R = e^{-\lambda(HI)} \tag{2.14}$$

$$POF = 1 - R \tag{2.15}$$

2.4. Health condition simulation

This section presents the results of health condition simulation for 5 sample transformers along 35 years in intervals of one hour. Health indices described in Section 2.2 were simulated taking into account previously proposed models such as furans content, but also taking into account historical data obtained from ENEL-Codensa presented in Appendix A.

The sample transformers are not new nor recently installed, therefore it is not expected to have a "long live". All indices simulated with historical tests data start with the last value registered on the tests from Appendix A.1. Most of last tests used were taken in 2018, which is the year of simulation start. For the other indices, load projection from Appendix A.2.1 is used. For finding HI, limits and weights from Table 2.3 were used, and for calculating $\lambda(HI)$, constants from Table 2.5.

Transformers to be analyzed are: T1, T2, T3, T4 and T5. From these transformers, T1 and T2 belong to the same substation, while the others belong to different substations. General information of these power transformers taken as example is shown in Table 2.6. From these transformers, only T5 is a three winding transformer, which means that its winding are separated in three different tanks. That is the reason why it counts with tests in every tank phase: A, B and C, presented in Appendix A.

Table 2.6.: Transformers general information.

Transformer	Installation year	Brand	U_{max} [kV]	S [MVA]
T1	1973	JEUMONT SCHNEIDER	115	20
T2	1970	MITSUBISHI	220	90
T3	2006	SIEMENS	115	40
T4	1987	MITSUBISHI	230	56
T5	1974	SIEMENS	500	90

With respect to aging information presented in Table 2.7, with the exception of T3, all transformers have been in operation for several years. However, this is not reflected in their DP and elapsed life values. Generally, a new transformer is considered to have a DP of 1100 [30]. When the transformer starts to lose its solid insulating properties, DP tends to decrease. A 200 value of DP represents that the transformer has reached the end of its life. The DP calculation formula was presented in Eq. (2.2). The DP values for all transformers were obtained from the last furans content test performed according to Appendix A.1.

Table 2.7.: Aging information

Transformer	Operation time [years]	DP	Elapsed life [years]
T1	45	512.76	6.80
T2	48	788.38	2.96
T3	12	1082.10	0.14
T4	31	621.81	5.08
T5	44	960.40	1.20

Hence, although T1, T2, T4 and T5 have been in operation for several years, they are not entirely aged according to their DP values. In the other hand, transformer T3 has been in operation for 12 years, however, according to is DP value, it is barely aged [30].

2.4.1. Transformer T1 health simulation

In Fig. 2.1 it is possible to appreciate the simulation of health indices for T1 along 35 years. For this transformer, while some indices tend to stay constant along time such as Load and AN, it is possible to observe an increase along time for the others. For example, furans index for this transformer starts with 0.8 out of 1, which represents a poor condition, taking into account the end of life of the transformer. DS and $H2O$ indices also tend to reach its maximum condition after 10 years of simulation, which does not mean that the transformer is dead, but means that failures inside the tank for deficit of dielectric strength or excess of water are more likely. In addition, $\%Sat$ and IFT indices tend to have a similar behaviour until year 15. Although DGA index has a high weight, the evolution of this index in time remains in good condition.

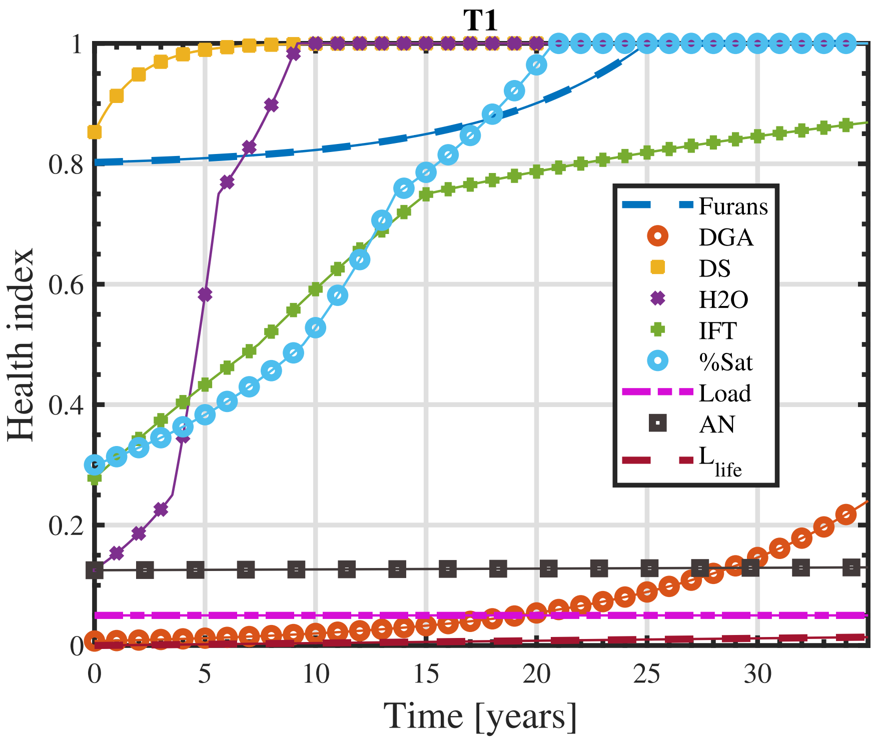

Figure 2.1.: Health indices simulation for T1.

Figure 2.2 presents the health condition (HI) in the left axis and failure rate of health condition ($\lambda(HI)$) in the right axis for transformer T1. According to Table 2.6, T1 was installed in 1973, which means that it has been operating around 45 years. However, according to the last value of its tests, its HI is near to 0.4 in 2018, when the simulation begins. This demonstrates that despite its 45 years of operation, this transformer has good health condition. This can be explained due to the low loading that can be appreciated from the historical load data from Fig. A.1. Besides, before furans content achieves 1 in condition, the worst condition of the asset by the end of its life is around 0.64.

Although simulation lasts 35 years, according to the furans content, the transformer is considered at the end of its life when furans index achieves 1. Therefore, although others indices do not reach 1 after 25 years of simulation, HI is considered 1 when the furans index is 1.

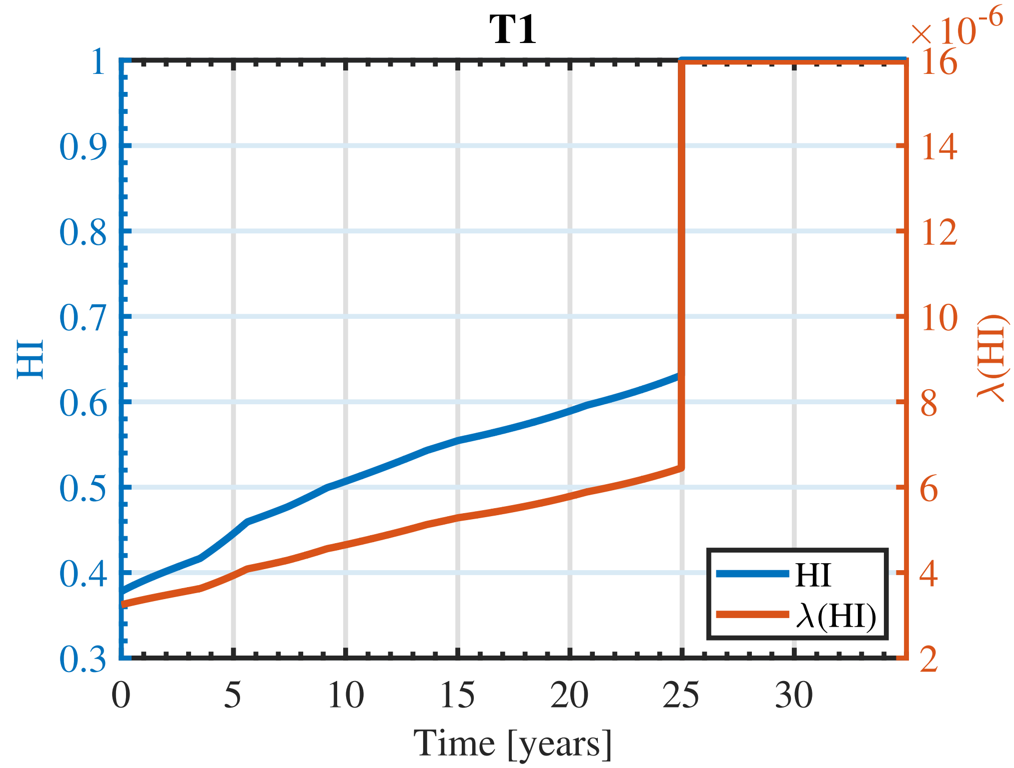

Figure 2.2.: Health condition and failure rate simulation for T1.

2.4.2. Transformer T2 health simulation

Transformer T2 is also an example of power transformer that has been in operation for several years according to Table 2.6, yet it is not considerably aged. This is a common behaviour in some operators that own several assets such as transformers in one substation. Figure 2.3 presents health indices of T2 along 35 years of simulation. Indices evolution for this transformer are different according to its lasts tests from Appendix A. Load index tend to remain constantly low due to its low loading from load projected. Therefore, its loss of life index remains at the minimum along simulation time. Furans and DGA indices, which have the highest weights, evolve slowly along time. The rest of physical-chemical indices tend to achieve its poorest condition after year 10.

Figure 2.4 shows the corresponding health condition and failure rate for T2. According to Fig. 2.4, at 2018 when the simulation starts, its HI is around 0.28. This value is relatively small taking into account its years of operation. According to its historical load in Fig. A.2, in the last five years, its loading has been between 0.2 and 0.4 p.u., which explains its good health condition. Besides, physical-chemical indices such as $\%Sat$, $H2O$ and IFT present a high and similar gradient in the first 5 years of simulation, which represent a high contribution to the HI weighted sum. In fact, after 6 years of simulation, its HI achieves 0.4 which is when some operators begin monitoring HI transformer for applying CBM.

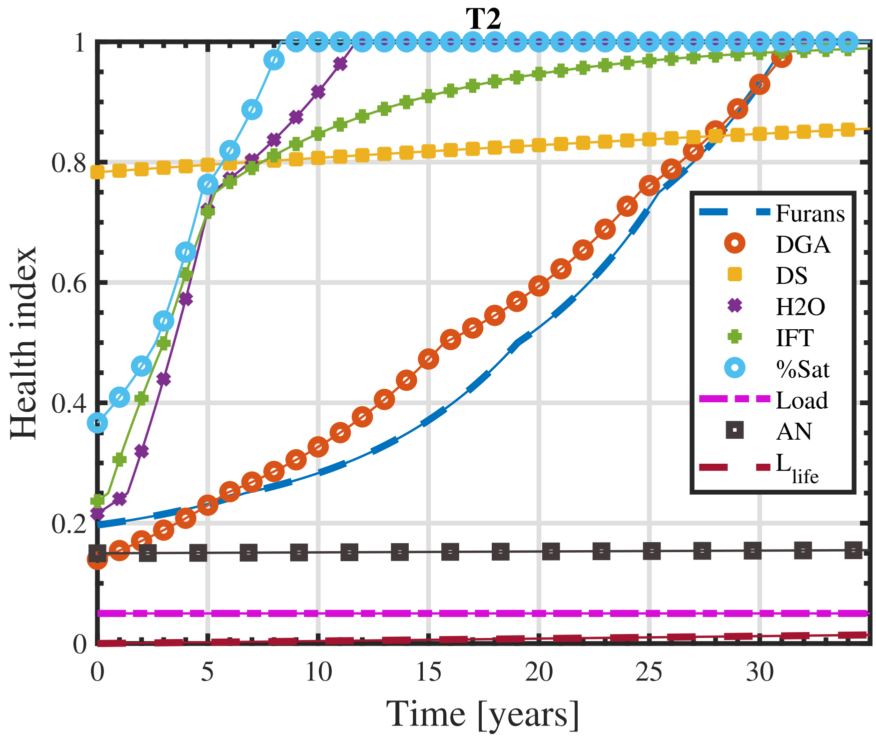

Figure 2.3.: Health indices simulation for T2.

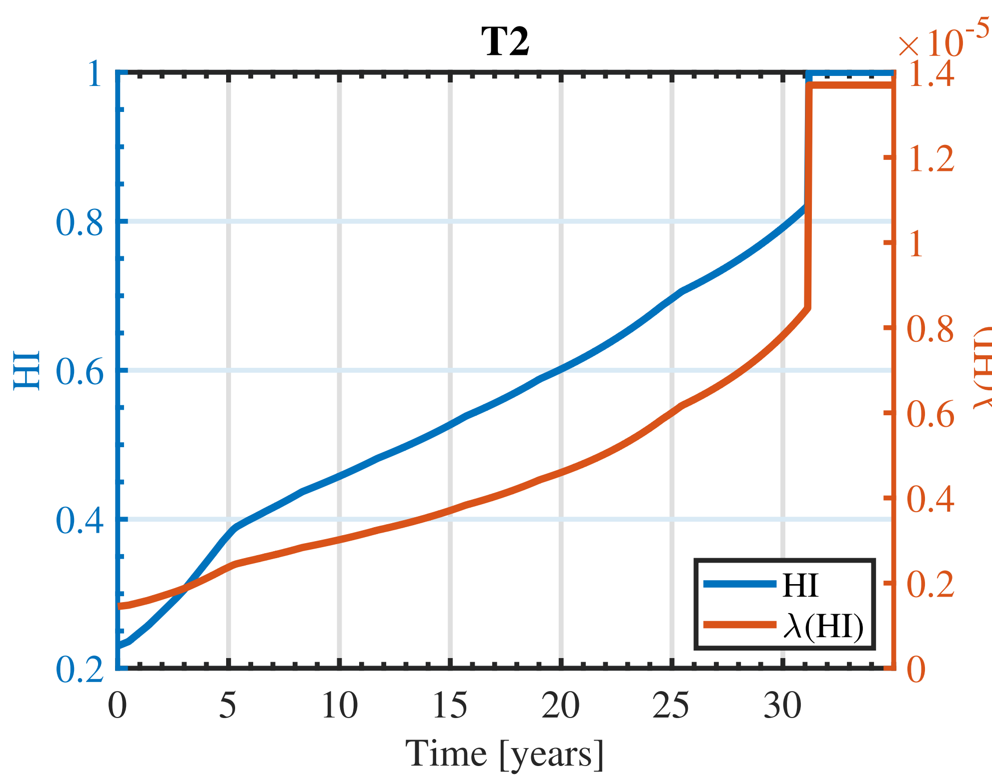

Figure 2.4.: Health condition and failure rate simulation for T2.

2.4.3. Transformer T3 health simulation

Figure 2.5 presents health indices of T3 in the simulation time. This is a case of a young transformer that was installed in 2006 as seen in Table 2.6. The DS index presents a quick evolution in the first years of simulation, and finally achieves its poorest condition before 5 years of simulation. Likewise, IFT presents a high gradient in the first five years of simulation, yet it reaches it poorest condition after 20 years of simulation along with $\%Sat$. When the simulation begins, its furans content reveals its low aging, and its end of life because of furans index is produced after 31 years of simulation. DGA and $H2O$ indices do not achieve their poorest condition before the end of life of the asset. Due to its low loading, Load and L_{life} indices remain with a minimum condition along the simulation time. AN index also remains contant in time.

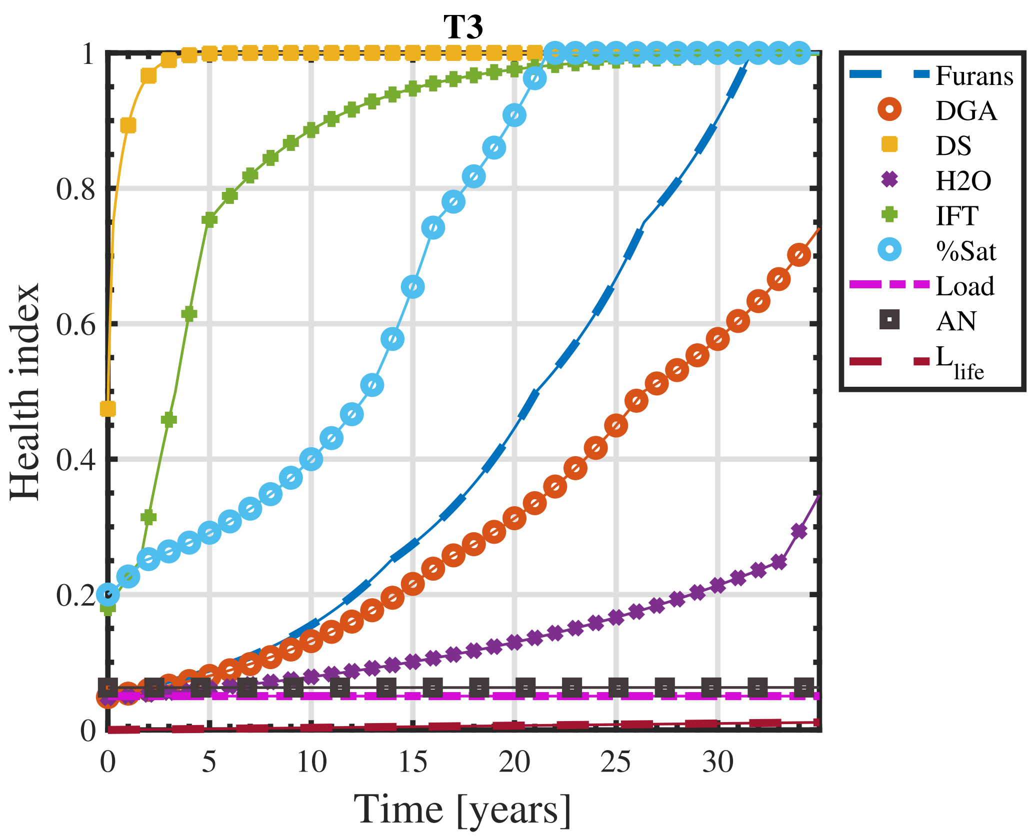

Figure 2.5.: Health indices simulation for T3.

Figure 2.6 presents the health condition (HI) and failure rate of health condition ($\lambda(HI)$) for transformer T3 in different axes. In this figure, it is possible to observe a higher gradient in the first five years of simulation. This is mainly the result of DS and IFT indices, that evolved quickly in this period of time. After year 5, gradient decreases. The transformer achieves 0.4 in HI after 15 years of simulation, which is an average evolution for a young transformer.

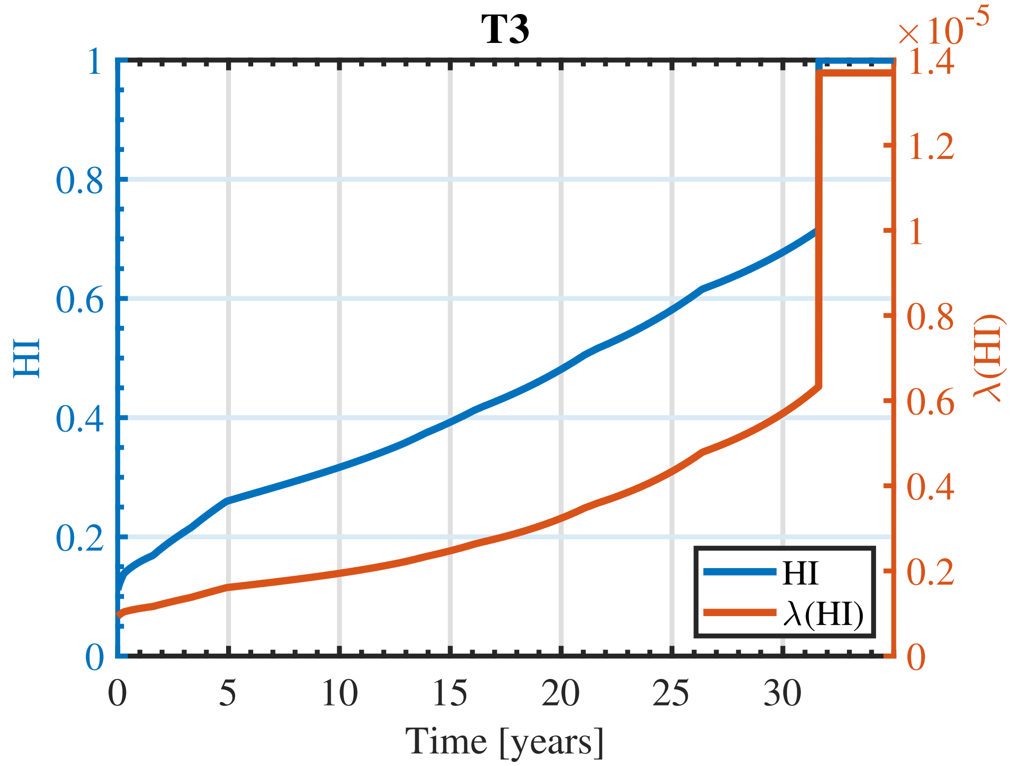

Figure 2.6.: Health condition and failure rate simulation for T3.

2.4.4. Transformer T4 health simulation

In Fig. 2.7 it is possible to observe health indices simulated for T4. This is another case of an old transformer, yet not entirely aged despite its years of operation according to Table 2.6. When the simulation starts, its furans index is around 0.5, but it takes around 30 years more in order to reach the end of its life. DS index presents a poor condition since the beginning of the simulation and achieves the poorest before 3 years of simulation. Other indices from physical-chemical test such as IFT and $H2O$ present a high and similar gradient in the first years of simulation. DGA and Furans indices show an average evolution for an old transformer. Its low loading from its projection load in Appendix A is noticeable in Load and L_{life} indices. AN index does not increase in the simulation time.

Figure 2.8 presents HI and $\lambda(HI)$ for T4. This transformer reaches its end of life before completing 30 years of simulation. The gradient of HI for this transformer tends to be higher en first five years of simulation, which can be the result of physical-chemical indices such as: DS, IFT and $H2O$.

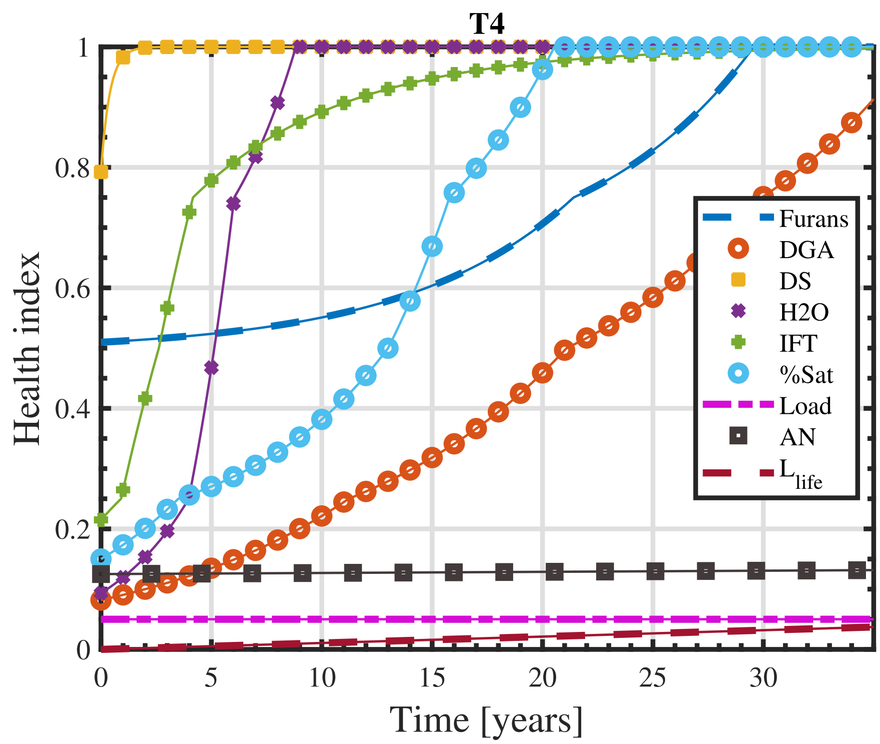

Figure 2.7.: Health indices simulation for T4.

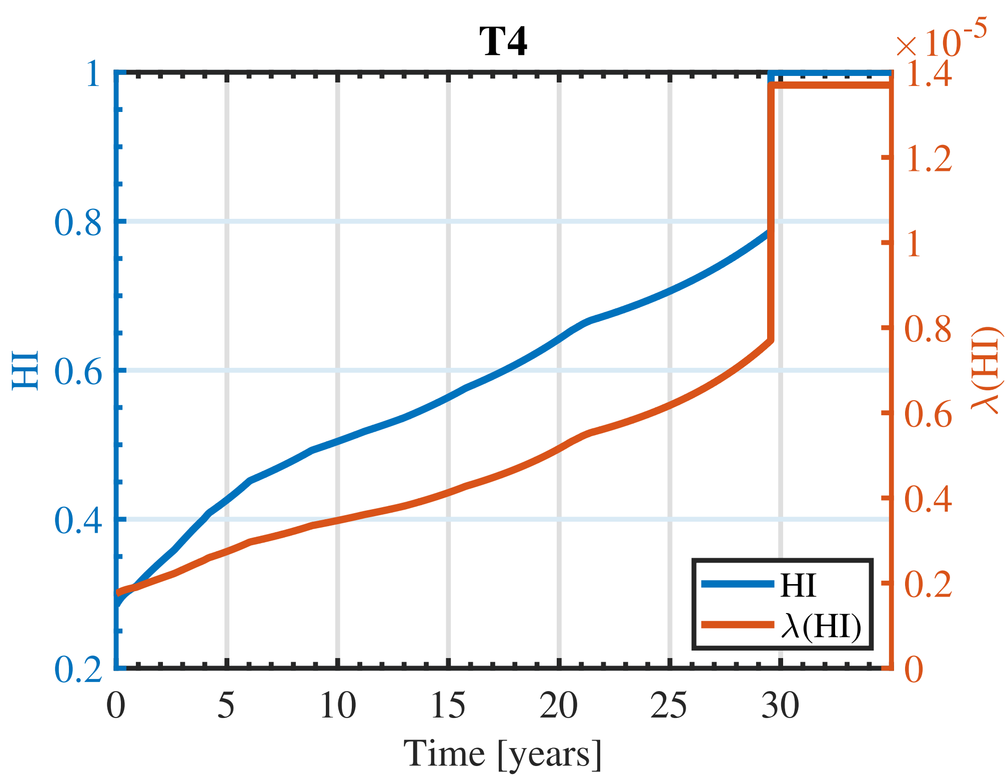

Figure 2.8.: Health condition and failure rate simulation for T4.

2.4.5. Transformer T5 health simulation

Finally, transformer T5 is the case of a transformer that has been highly loaded according to its historical load from Fig. A.5. This can explain its poor condition in some indices such as DS, IFT and %Sat when the simulation begins. In addition, these indices evolve with a similar behaviour in the firsts years of simulation. These poor values in physical-chemical indices may indicate a higher probability of failures inside the tanks. Its value of Load and loss of life indices corroborate the high loading that presents this taken from Appendix A. causes a high loss of life. Yet, this does not mean that the asset is at the end of its life. In fact, its last value of furans content displays a young transformer with furans index below 0.1 when the simulation begins. AN index remains constant for this transformer. Furans and DGA indices present an average evolution for an old transformer. Health indices of this transformer are shown in Fig. 2.9.

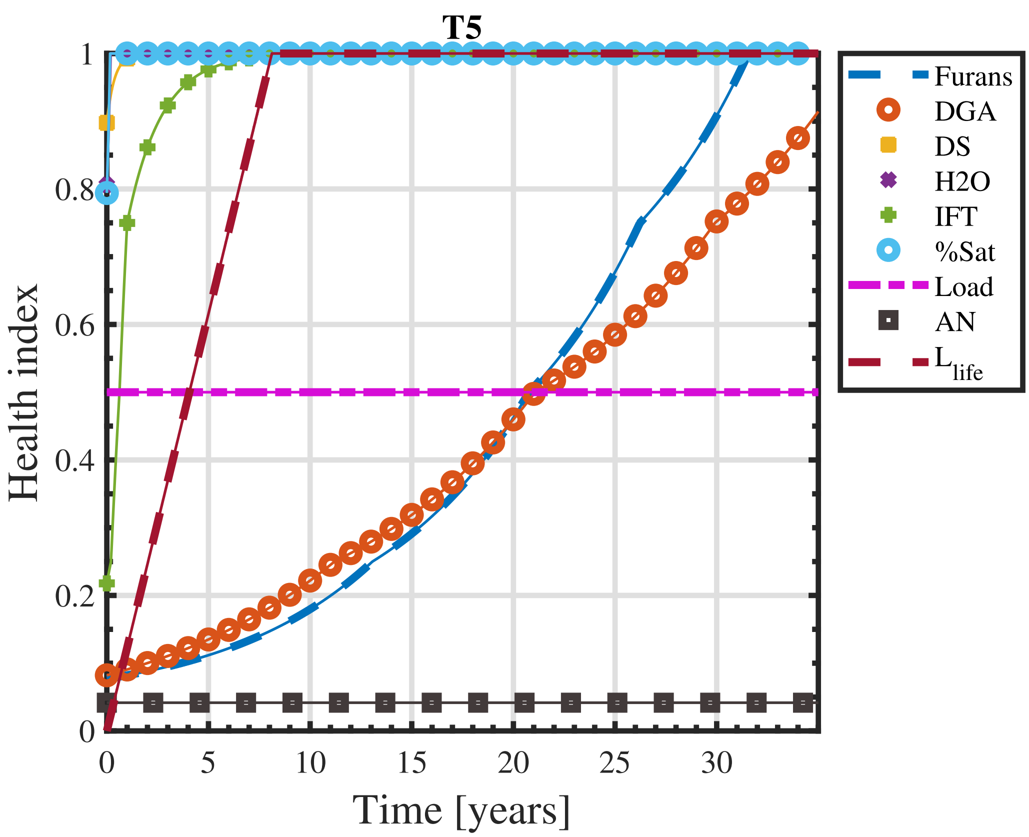

Figure 2.9.: Health indices simulation for T5.

According to its health indices evolution presented before, when the simulation starts with values of the last test in 2018, this transformer presents a health condition of 0.23, yet it increases until 0.4 in only one year. This represents a high gradient due to the quick evolution of DS, IFT and $\%Sat$. This transformer reaches its end of life after 32 years of simulation according to its furans index as shown in Fig. 2.10.

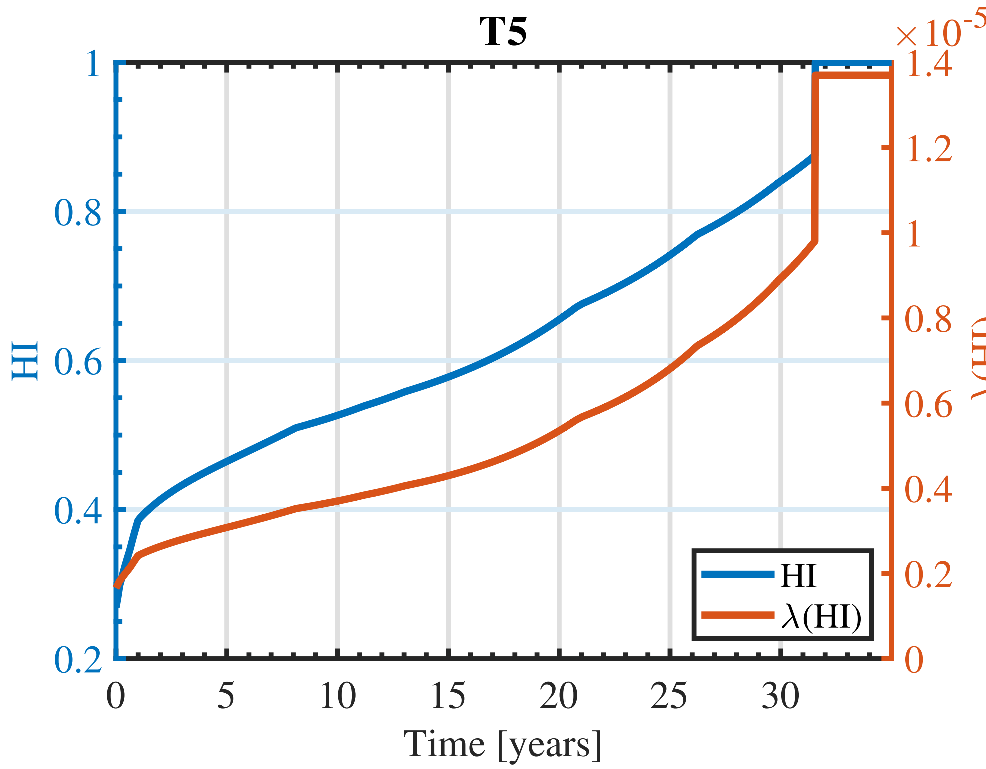

Figure 2.10.: Health condition and failure rate simulation for T5.

In summary, the maximum health condition for all transformers was only achieved because furans index evolved until its poorest condition. Although, that does not mean that all indices are in their poorest condition. According to the health indices simulated for all sample transformers, after 35 years of simulation, most of these indices did not achieve their worst condition. The end-of-life is an important aspect to take into account when managing an asset. For power transformers, this end-of-life is directly connected to the furans content. For this reason, furans index generally has a higher weight for the evaluation of health condition HI.

Conclusions

- The low loading presented in historical load data from Appendix A.2 corroborated that sample transformers are not considerably aged according to the furans content of the last test in Appendix A.1.
- This research presented a health condition model with 9 health indices in order to provide a more robust evaluation of HI. However, from the results obtained, it is possible to conclude that indices that tend to remain constant in time do not represent

a considerable contribution to the condition monitoring, such as AN. Likewise, it is possible that when the asset is not considerable loaded, its L_{life} and Load index do not contribute to the evolution of HI. This was the case of all transformers, with the exception of T5.

- From the indices related to the oil condition such as DS, IFT, $\%Sat$ and $H2O$, it was possible to observe similar patterns in their evolution in some points of the simulation, since they are closely related. Besides, the addition specially in T1, T2, T4 and T5.
- Through the health condition simulation of the sample transformers, it was confirmed that a power transformer can reach end of its life before its health condition achieves its poorest condition. This was the case of all sample transformers. It was also corroborated that these sample transformers arrive at the end of their life before the 35 years of simulation, due to its initial furans content.

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3. Maintenance applied to power transformers

Summary

In this chapter, AM theory is applied for power transformers. First, there is an introduction about what is AM and why it is applicable for power transformers through its condition monitoring. Then, maintenance is presented as a strategy for managing power transformers, where the maintenance schemes are defined. Later, the evaluation of schemes is presented for sample transformers taking into account their HI simulated in Chapter 2.

Introduction

Asset Management is composed by a series of actions in order to change the operation of a group of assets and obtain a gain over their useful life. For instance, it is expected to recover the economical return by ensuring safety and service levels [1].

Maintenance, considered as an strategy of AM, can help the operator to achieve these objectives and, it is also one of the most implemented for several assets, specially in the electrical system. For applying maintenance, first it is important to know the condition of the asset and the impact that this action may have on this condition. Analyzing the condition of the assets allows to consider other important aspects for managing an asset, such as [2]:

- Probability of failure, risk of failure, and reliability [2].
- Effective age versus actual age [3].
- Remaining life and life consumption [3].
- End-of-life [2].

For analyzing the effects of applying maintenance in power transformers, health condition simulations presented in Chapter 2 are used.

3.1. Maintenance as strategy for managing power transformer

Asset Management refers to the different actions and strategies that are applied to the assets with the purpose of improving their condition and reliability, taking into account the best combination between quality and the economical return for the service. Within these strategies, particularly for power transformers, maintenance is used in order to improve the asset condition, as well as the failure rate and other reliability indices [4]. This will reflect on an increase in the useful life of the asset [5]. In this strategy, four maintenance schemes are defined and classified according to Fig. 3.1 [1].

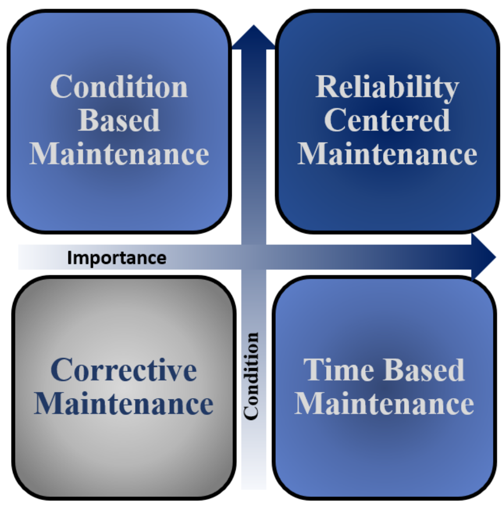


Figure 3.1.: Maintenance schemes.

- **Corrective Maintenance:** This is the type of maintenance in which there is no previous analysis for the decision of applying a maintenance. It briefly consists in developing a maintenance action or replacement when the asset fails. However, this type of maintenance may imply serious problems of reliability and compensation costs for the operator, since its condition is not monitored. Usually, the corrective maintenance is applied mainly to assets whose investment is not significant for the operator, or to those assets with a non-significant probability of failure [1].

- **Time based maintenance:** This type of maintenance, as its name indicates, is based on a period of time depending on the type of asset. Then, a time interval is established in which actions of maintenance are performed. This time interval may be suggested by the manufacturer or according to the operator needs [1]. This is the most common type of maintenance applied to assets in power systems. Some of the actions comprised in this type of maintenance are annual tests, loading check, or maintenance in specific parts. Generally, this maintenance scheme is not recommended for assets with an advanced health condition.

- **Condition Based Maintenance:** It is one of the most effective schemes of maintenance due to the monitoring of the condition performed. However, it implies the development of a model for every asset in order to prioritize or rank the set of assets [1]. It has as advantage the possibility of orientating maintenance actions to specific parts of the asset that may need prioritized maintenance.

- **Reliability Centered Maintenance:** Reliability indices of an asset depend on its condition. Therefore, this type of maintenance considers condition too, but reliability is prioritized depending on the performance impact of the asset [1]. Then, the maintenance actions are focused on those assets with lower reliability indices. In this case, it can also be considered to prioritize those assets that are more critical for the energy supply. Maintenance actions can be specified for every kind of asset, depending on their importance.

Previous studies on this topic have concluded that in some cases an investment in maintenance may not be necessarily the economically optimal solution [6], although it is feasible because of its gain in reliability indices. With respect to a power transformer, the schemes with better performance are CBM and TBM [6], since they improve the service while maintaining a good proportion with the economical return. This can be achieved by balancing reliability indices [7].

3.2. Evaluation of maintenance schemes

When it comes to simulate a certain model, it is necessary to set some conditions depending on the model. For evaluating the effect of maintenance when managing a power transformer, some considerations are set:

- An action of maintenance represents an improvement of health condition seen as a setback of one or more individual health indices to a previous condition. These indices on which are expected changes are those that are mainly focused in the tank/oil of the transformer.

- Costs by energy not supplied (ENS) will depend on the probability of interruptions obtained for each failure rate $\lambda(HI)$.

- In order to observe the effect of maintenance schemes in HI and $\lambda(HI)$, other costs are not considered in this part.

- The simulation of probability of interruptions depends entirely on the failure rate, yet it is not exact, then there is no certain way to establish when the asset will fail. Hence, corrective maintenance will not be included.

Taking into account the brief description of maintenance schemes presented in Section 3.1 and the bibliography related to maintenance as strategy for AM, there is no consensus nor indicative of which criteria should be considered for applying these maintenance schemes. Therefore, it was necessary to establish the criteria according to the definition of these maintenance schemes and the experience of ENEL-Codensa.

For applying time-based maintenance (TBM), it is necessary to establish a period of time depending on the type of asset and the operator needs. Most of operators tend to apply TBM with a period of time between 4 to 6 years. For this thesis, TBM will be applied with an interval of time of five years, starting in year 5 until the asset achieves 1 in HI. The impact expected in each maintenance is a setback to a previous condition of health indices that are obtained from tests applied to the tank/oil of the transformer. These indices are: DGA, DS, IFT, $\%Sa$t and $H2O$. In spite of furans content is obtained from an insulating oil sample, furans index is not a reversible index, due to the fact that the insulating properties of the paper inside the transformer are not reversible. Generally, when oil inside the tank is filtered for improving other indices, furans content is restarted, but this does not mean that the aging has been delayed. The rest of the indices will not be affected either.

With respect to condition-based maintenance (CBM), most operators start applying maintenances after the transformer has achieved a health condition of 0,4. This is the first criterion for CBM application. The other criterion for applying CBM is to find those moments when HI has higher gradient, which means that its health condition is getting accelerated. Generally, a change in HI gradient is due to a change of condition in one or several health indices. For this reason, HI gradient is found every year in order to identify the moments for applying CBM.

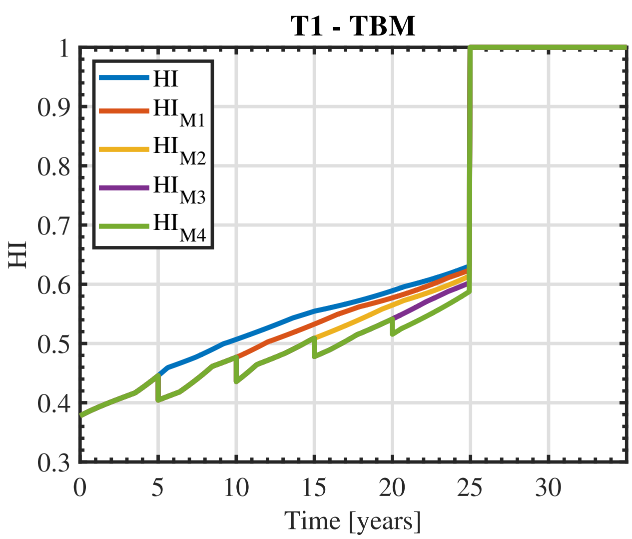
Finally, reliability-centered maintenance (RCM) follows the condition of the asset but also its importance. Therefore, it takes into account the evolution of reliability indices of the asset. Since, it is impossible to estimate some reliability indices without the whole information of the operator, indices focused on a single asset are used such as expected interruptions and probability of failure as presented in Section 2.3.1. The criterion used for applying RCM is finding those moments when there is an increase percentage in interruptions expected between years. Sames as TBM and CBM, only DGA, DS, IFT, $\%Sat$ and $H2O$ will be affected after every maintenance.

For evaluating this schemes of maintenance, HI curves from simulations presented in Section 2.4 are used. After every maintenance, a new curve of health condition is found (HI_{M_i}).

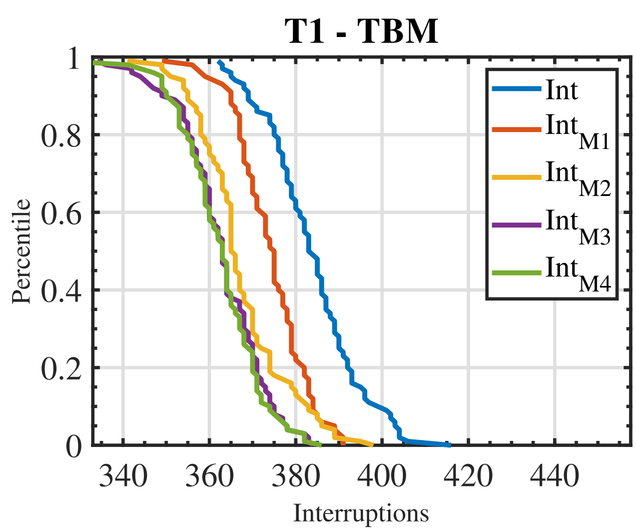
Expected interruptions will be evaluated in order to observe the total effect of applying these maintenance schemes. These expected interruptions are obtained through a Montecarlo simulation of failure rate ($\lambda(HI_M)$) with 100 repetitions along the simulation time. It consists in evaluating failure rate through the simulation of random numbers, in order to observe the distribution of this numbers. Expected interruptions are presented as a probability distribution, from which different percentiles will be used for analyzing the variations in results. Although health indices simulation is evaluated along 35 years, it is important to mention that expected interruptions are evaluated only from year 0 until HI achieves 1. Since a transformer valued with 1.0 in furans index is considered completely degraded, there is no point in observing its expected interruptions when health condition is 1.0.

3.2.1. Maintenance schemes applied to T1

Figure 3.2a shows the different HI curves found after applying TBM for T1. In this case, before health condition achieves 1, 4 maintenances were applied, generating 4 different curves. Besides, in Fig. 3.2b are shown expected interruptions for every corresponding curve. By applying every maintenance, it is observed a clear reduction in HI evolution according to Fig. 3.2a.



(a) HI curves per maintenance for TBM - T1



(b) Interruptions expected per maintenance for TBM - T1

Figure 3.2.: TBM results for T1

Likewise, in Fig. 3.2b there is a reduction of **21** interruptions between curve Int to Int$_{M4}$ in their P_{50} according to Table 3.1. However, reduction between Int$_{M3}$ and Int$_{M4}$ or even between Int_{M2} and Int_{M3} are not considerably high taking into account the cost that may imply applying maintenances M3 and M4. In this case, this is a decision that should make the operator in order to determine until which moment it is feasible keep applying TBM, or if it is better to try a different maintenance scheme.

Along the 25 years in which T1 has HI is lower than 1, it was possible to apply a total of 4 maintenances for T1. Therefore, $HI_{TBM} = HI_{M4}$ according to Fig. 3.3.

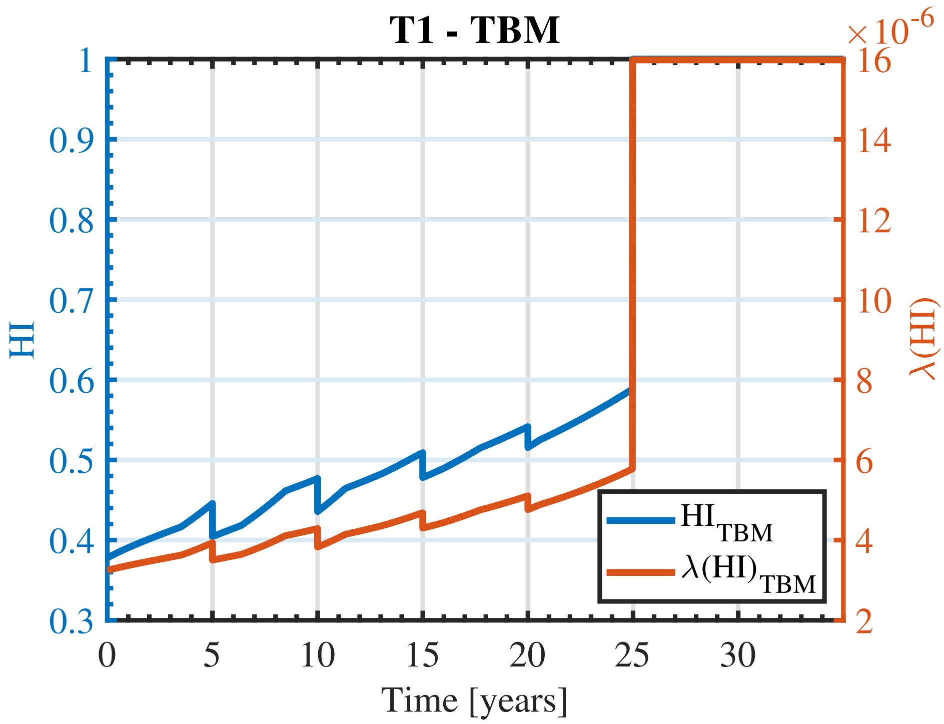
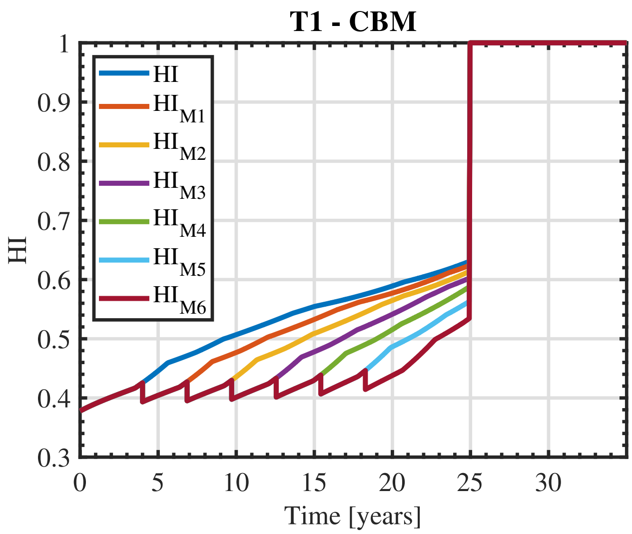


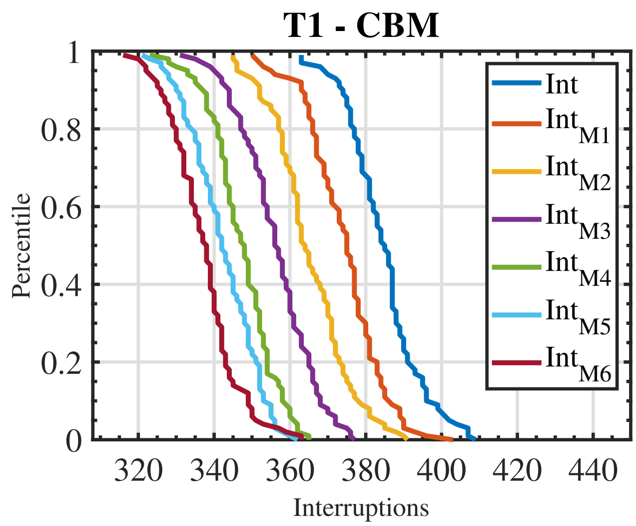
Figure 3.3.: HI and $\lambda(HI)$ for TBM - T1

With respect to CBM, a total of 6 maintenances were applied starting around year 4, when a change in HI gradient is found. The curves generated for T1 are presented in Fig. 3.4a. The expected interruptions for each of these curves are presented in Fig. 3.4b. Every of these expected interruptions curves show a decrease after every maintenance. However, in the lasts maintenance, the decrease is smaller, which can mean that this maintenance is probably not that useful. The reduction in interruptions expected for this case is **46**, which is higher than the TBM results, according to Table 3.1. This means that a maintenance based in condition can be more accurate than a time-based maintenance for this transformer.

Resulting HI curve for CBM is presented in Fig. 3.5, being $HI_{CBM} = HI_{M6}$.



(a) HI curves per maintenance for CBM - T1



(b) Interruptions expected per maintenance for CBM - T1

Figure 3.4.: CBM results for T1

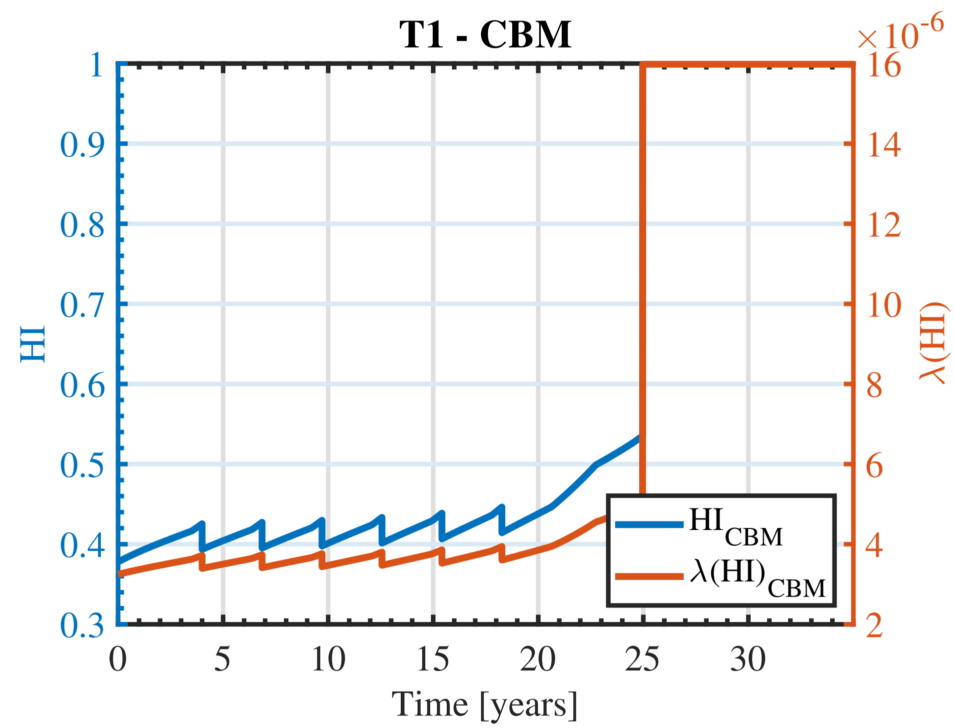
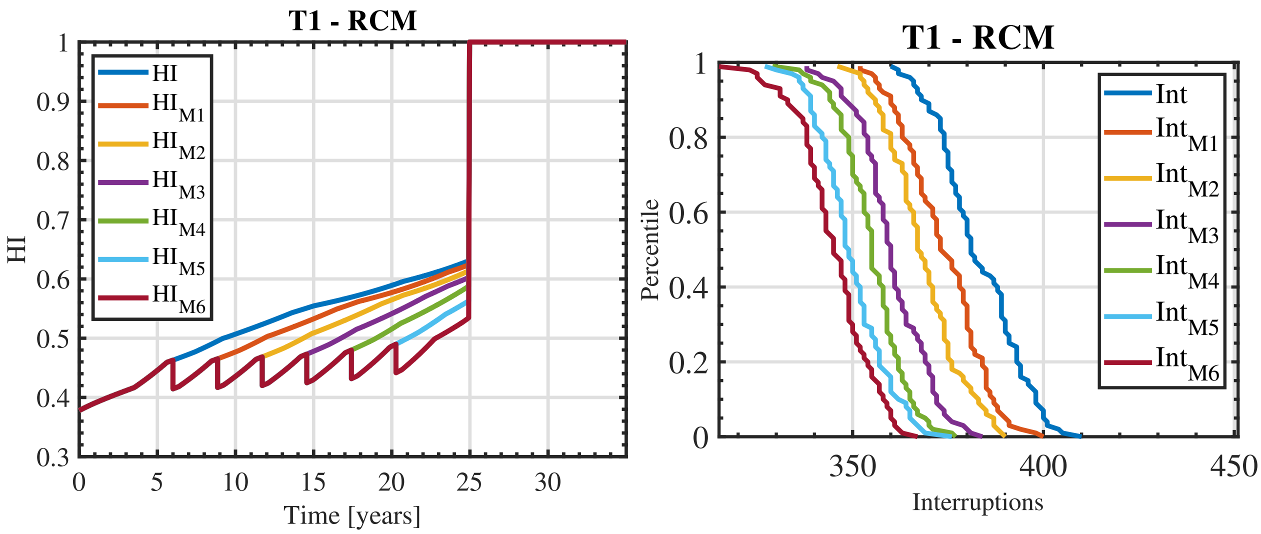


Figure 3.5.: HI and $\lambda(HI)$ for CBM - T1

Figure 3.6a shows all HI curves generated for T1 after applying RCM. The corresponding expected interruptions are presented in Fig. 3.6b.



(a) HI curves per maintenance for RCM - T1

(b) Interruptions expected per maintenance for RCM - T1

Figure 3.6.: RCM results for T1

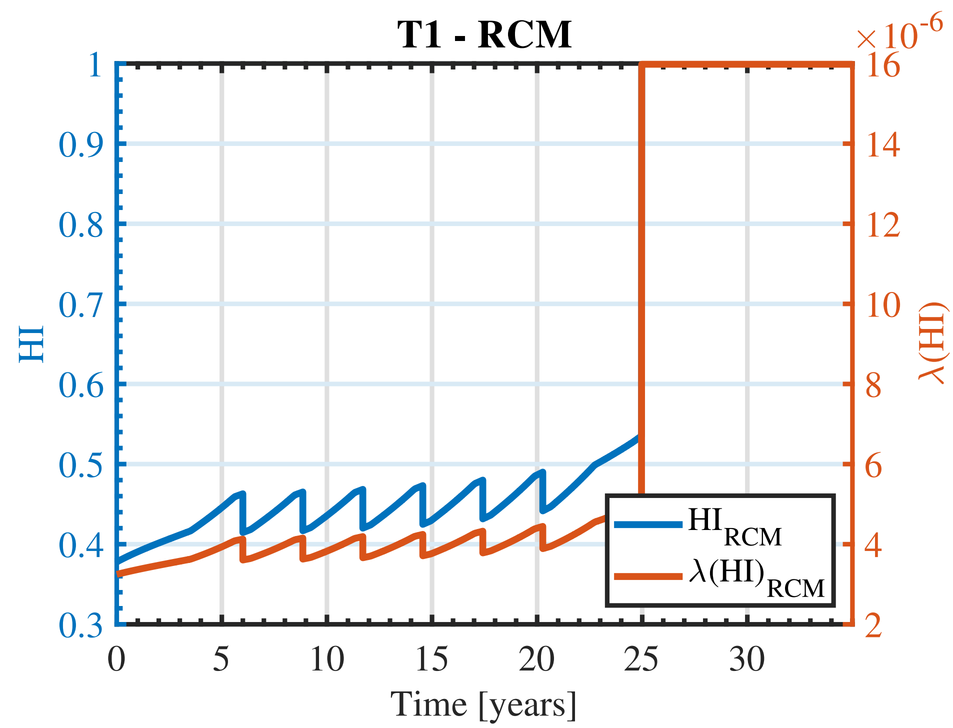


Figure 3.7.: HI and $\lambda(HI)$ for RCM - T1

First maintenance is applied around year 8, and then 5 maintenances more are applied until year 23. In every new HI curve, it is noticeable a clear reduction in health condition after every maintenance applied along time. The reduction in expected interruptions for this case is **29**, which is lower than the CBM results. Taking into account the three schemes evaluated, the best results for this transformer are presented by CBM. Resulting HI curve for this case is presented in Fig. 3.7, where $HI_{RCM} = HI_{M6}$.

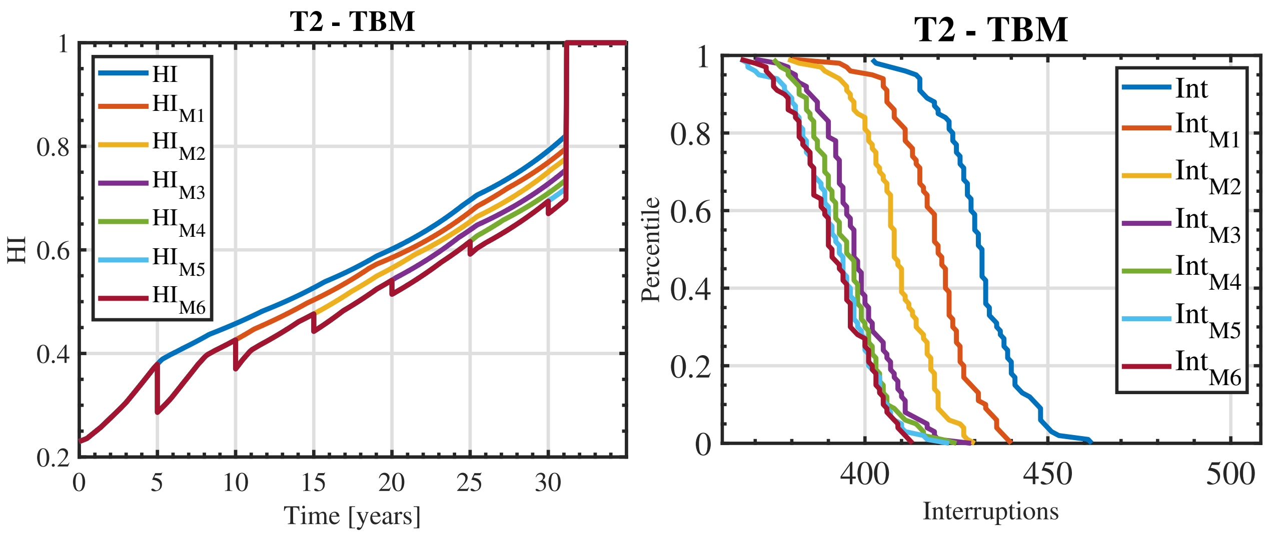
Table 3.1 presents a summary of expected interruptions reduction from 50^{th} percentile (P_{50}) evaluated in T1 per maintenance scheme. In every row, it is possible to appreciate reduction of expected interruptions between Int and the corresponding Int_{M_i}. For example, for RCM, reduction between Int-Int_{M4} and between Int-Int_{M5} is almost the same. This means that the last maintenance applied did not have a significant effect on the transformer. On the contrary, for TBM and CBM, after every maintenance, a reduction is appreciable. As mentioned before, and in accordance with results of Table 3.1, the best scenario for this transformer is CBM scheme. As this asset starts the simulation with a value of 0.4 for HI, then the first maintenance is applied by the fourth year. With this scheme it is possible to achieve a reduction of **46** expected interruptions according to the percentile 0,5. This represents a $11,9\%$ of reduction compared to the health condition without maintenance schemes applied. For this case, applying more maintenances may not be useful since the improvement in HI and expected interruptions can be minimal. All applied maintenances after the 20^{th} in TBM and RCM do not represent a considerable improvement in the assessment of the transformer.

Table 3.1.: Results summary for T1

Reduction in expected interruptions with P_{50}	TBM	% TBM	CBM	% CBM	RCM	% RCM
Int - Int_{M1}	9	2,3	9	2,3	11	2,9
Int - Int_{M2}	19	5	20	5,2	17	4,5
Int - Int_{M3}	21	5,5	28	7,3	24	6,3
Int - Int_{M4}	21	5,5	36	9,4	29	7,6
Int - Int_{M5}	-	-	42	10,9	35	9,2
Int - Int_{M6}	-	-	46	11,9	39	10,2

3.2.2. Maintenance schemes applied to T2

For transformer T2, the same criteria for TBM were applied. Since this transformer starts simulation with a lower HI value, its end of life is presented after 31 years of simulation. For this transformer, a total of 6 maintenances were applied, although the sixth maintenance may be considered unnecessary. The curves generated for each of these maintenances are shown in Fig. 3.8a.



(a) HI curves per maintenance for TBM - T2 (b) Interruptions expected per maintenance for TBM - T2

Figure 3.8.: TBM results for T2

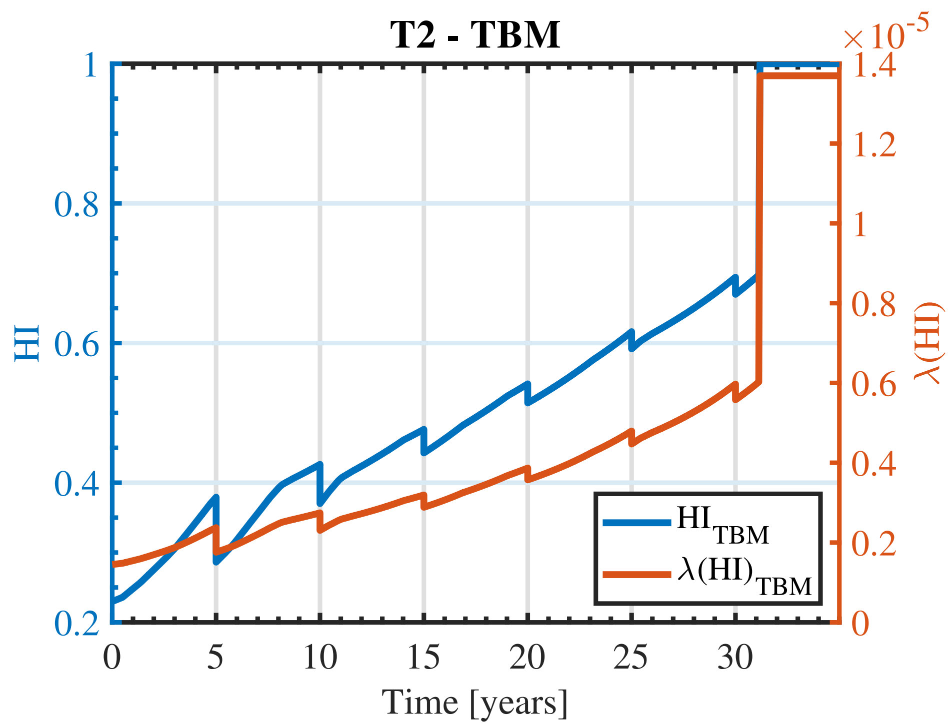
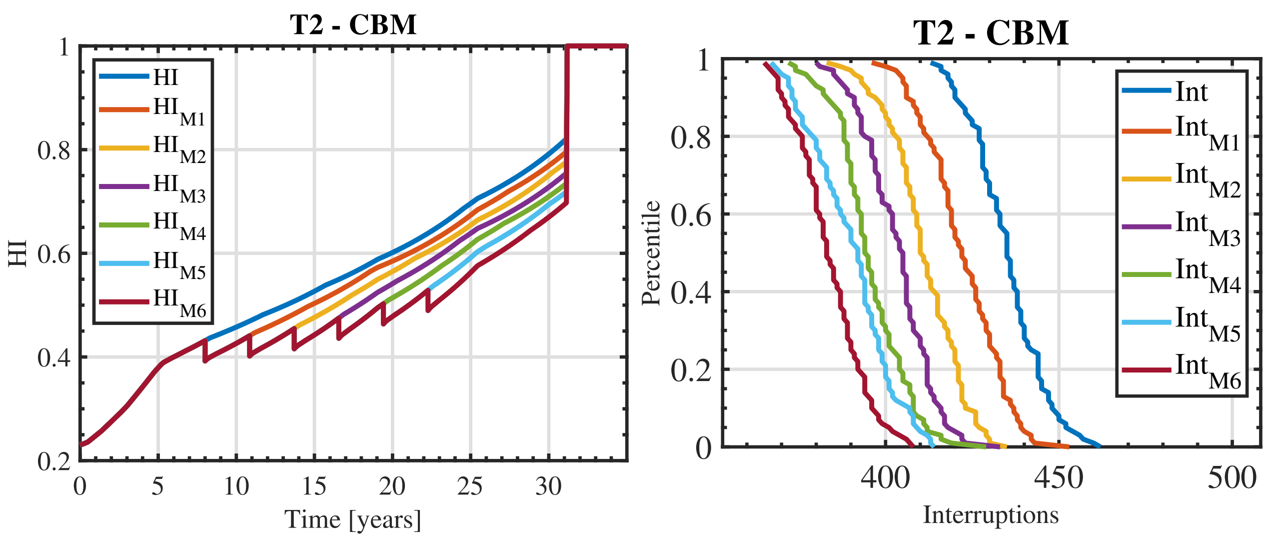


Figure 3.9.: HI and $\lambda(HI)$ for TBM - T2

In the same way, Fig. 3.8b presents the interruptions expected for every of these HI curves. The reduction of expected interruptions between Int and Int_{M6} is **45** taking as base percentile 0.5 from Table 3.2. In this case, it is observable that the difference between Int_{M6}, Int_{M5} and Int_{M4} are not representative according to Table 3.2. In this case, it may depend on the operator deciding whether if it is feasible to apply these maintenances.

According to these results, Fig. 3.9 presents the resulting curve for T2, $HI_{TBM} = HI_{M6}$.



(a) HI curves per maintenance for CBM - T2

(b) Interruptions expected per maintenance for CBM - T2

Figure 3.10.: CBM results for T2

For the CBM scheme applied to T2, different curves are shown according to the maintenances applied. Since this transformer achieves 0.4 in HI after 6 years of simulation, first maintenance is applied around year 8 when a gradient variation in HI is found. These curves generated are observed in Fig. 3.10a.

The corresponding interruptions expected of these curves are presented in Fig. 3.10b, where the difference between Int and Int_{M6} is around **53** interruptions as seen in Table 3.2. This reduction is barely higher than the one obtained by TBM, yet the best option so far.

Resulting HI curve for CBM is presented in Fig. 3.11, as $HI_{CBM} = HI_{M6}$.

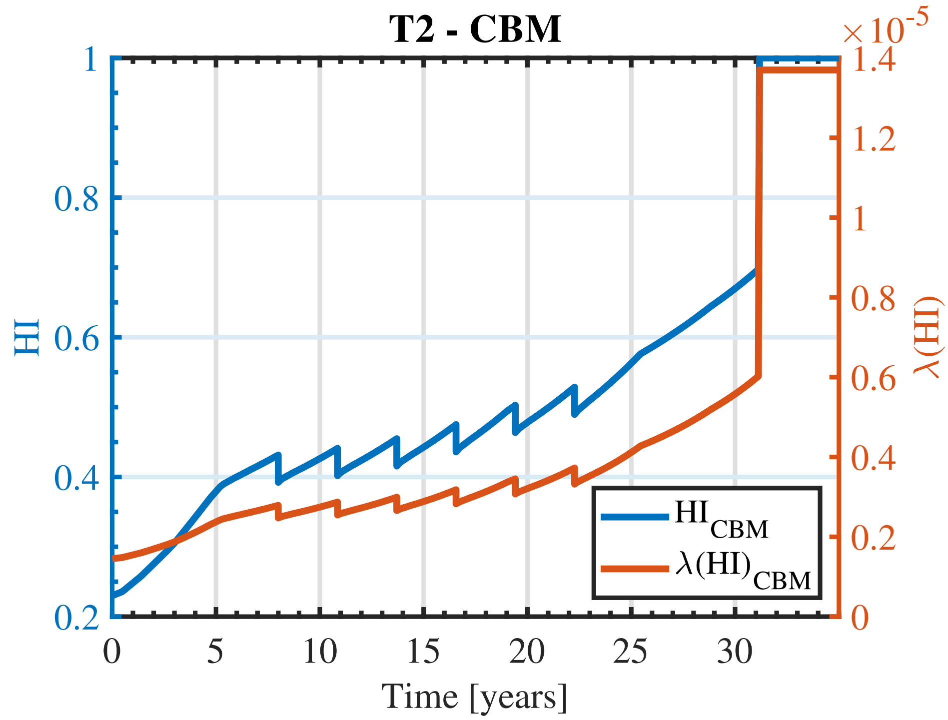
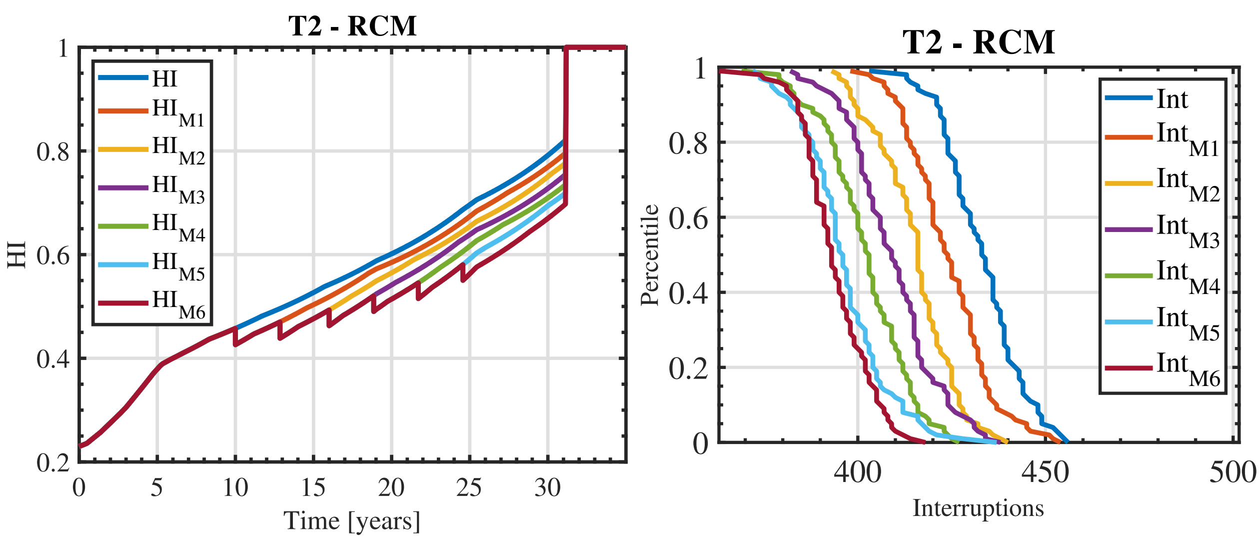


Figure 3.11.: HI and $\lambda(HI)$ for CBM - T2



(a) HI curves per maintenance for RCM - T2

(b) Interruptions expected per maintenance for RCM - T2

Figure 3.12.: RCM results for T2

With respect to RCM applied to T2, Fig. 3.12a presents HI curves generated after every maintenance applied starting around year 12 until year 27. It is appreciable a small effect on the transformer health condition after M4. The corresponding expected interruptions per HI curve are shown in Fig. 3.13. Same as TBM applied for this transformer, maintenance actions after the year 20 do not represent a considerable improvement in the health condition of the transformer.

Expected interruptions difference between M3 and M4, and between M5 and M6 are barely noticeable, which is in concordance with results from Table 3.2. Yet, the total reduction between Int and Int_{M6} is **43**, which is good but lower than for CBM. Therefore, for this transformer CBM remains as the best possible option for assessing.

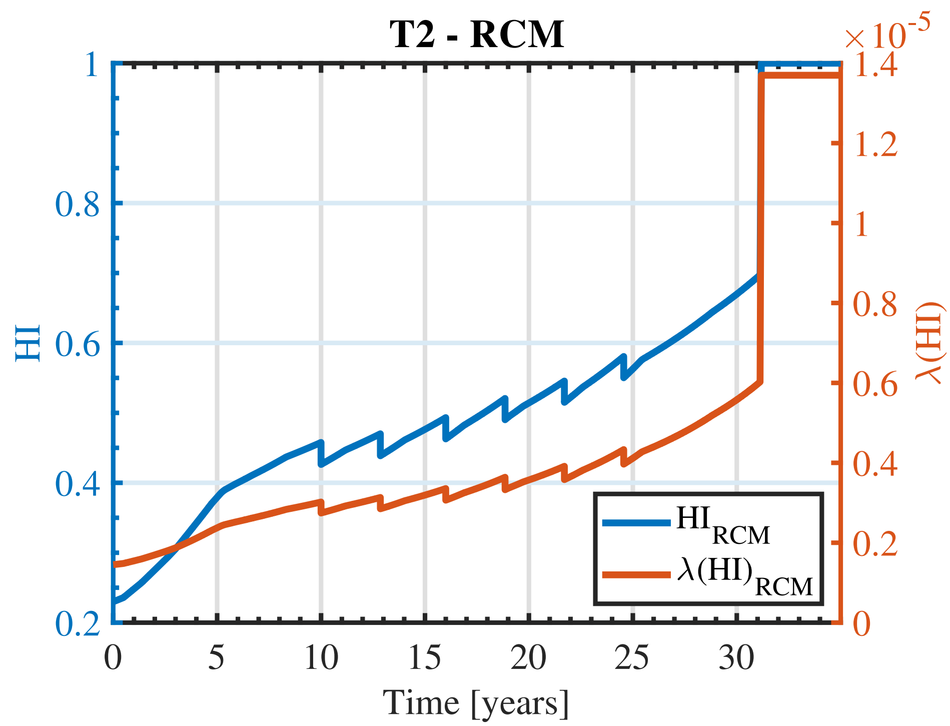


Figure 3.13.: HI and $\lambda(HI)$ for RCM - T2

In Table 3.2 are presented the results of interruptions reduction evaluated in T2 per maintenance scheme.

For this transformer, maintenance M6 for TBM seems to have a negative impact on the transformer health condition, since the reduction decreases between M5 and M6. However, a variation of ± 1 in distributions obtained by Montecarlo simulations with similar data, are highly common. Therefore, it is possible to consider negative variations as no variation. Likewise, maintenance M6 for RCM does not represent a high effect the expected interruptions of the transformer. As mentioned before, best scenario for this transformer was found through CBM scheme. By applying CBM to T2, a reduction of **53** expected interruptions is obtained. This reduction represents a reduction of $12,2\%$ with respect to the base case. TBM and RCM schemes also present good results for this transformer, however maintenances applied by TBM or RCM after year 20 turned out to be less meaningful, since the reduction in expected interruptions is minimal.

Table 3.2.: Results summary for T2

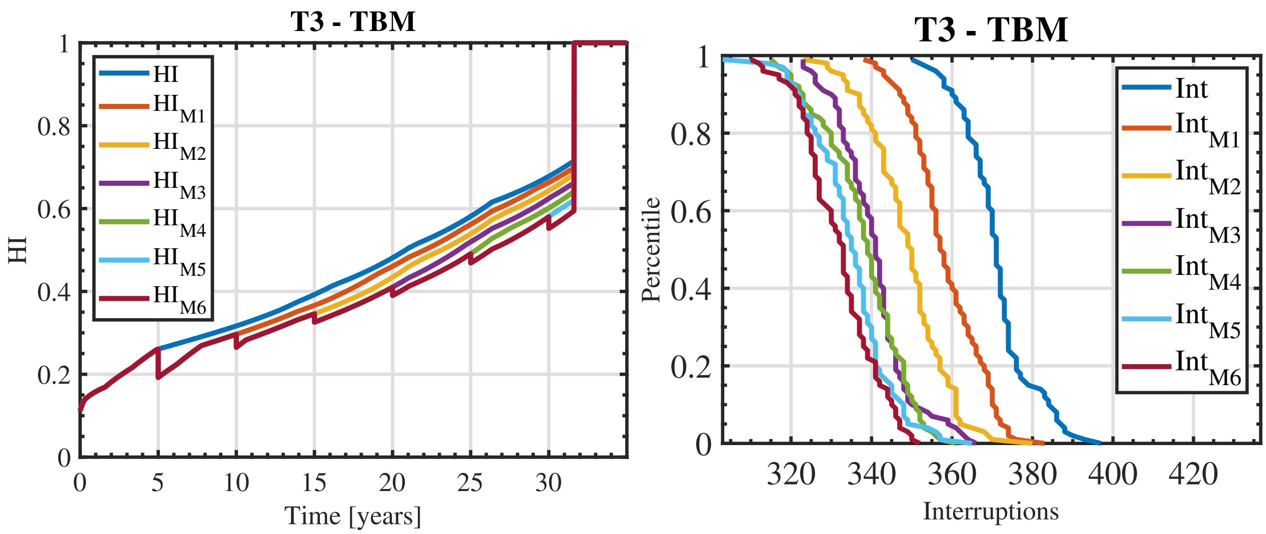
Reduction in expected interruptions with P_{50}	TBM	% TBM	CBM	% CBM	RCM	% RCM
Int - Int$_{M1}$	16	3,7	14	3,2	12	2,8
Int - Int$_{M2}$	28	6,5	26	6	20	4,6
Int - Int$_{M3}$	39	9	31	7,1	27	6,2
Int - Int$_{M4}$	41	9,5	42	9,7	33	7,6
Int - Int$_{M5}$	43	10	44	10,1	40	9,2
Int - Int$_{M6}$	45	10,4	53	12,2	43	9,9

3.2.3. Maintenance schemes applied to T3

The HI evolution of transformer T3 is similar to T2, since it achieves 1 in health condition after 32 years of simulation. Therefore, for this transformer, 6 maintenances can be applied along its lifetime, however the sixth maintenance might be unnecessary since it is close to the end of its life and may not have a noticeable impact. The curves generated for each of these maintenances are presented in Fig. 3.14a.

Likewise, for every of these HI curves, expected interruptions are presented in Fig. 3.14b. The reduction of expected interruptions between Int and Int$_{M6}$ is **37** taking as base percentile 0.5 according to Table 3.3. In this case, maintenance M6 seems to have a negative impact on the transformer in interruptions expected.

From curves presented before, Fig. 3.15 presents the resulting curve of HI, where $HI_{TBM} = HI_{M6}$.



(a) HI curves per maintenance for TBM - T3

(b) Interruptions expected per maintenance for TBM - T3

Figure 3.14.: TBM results for T3

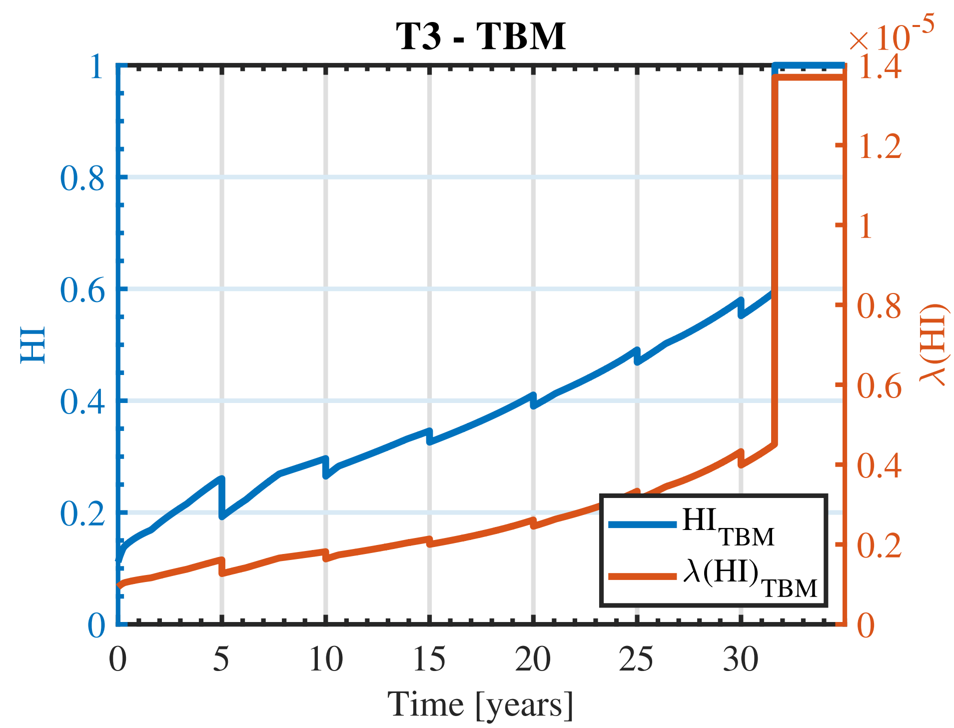
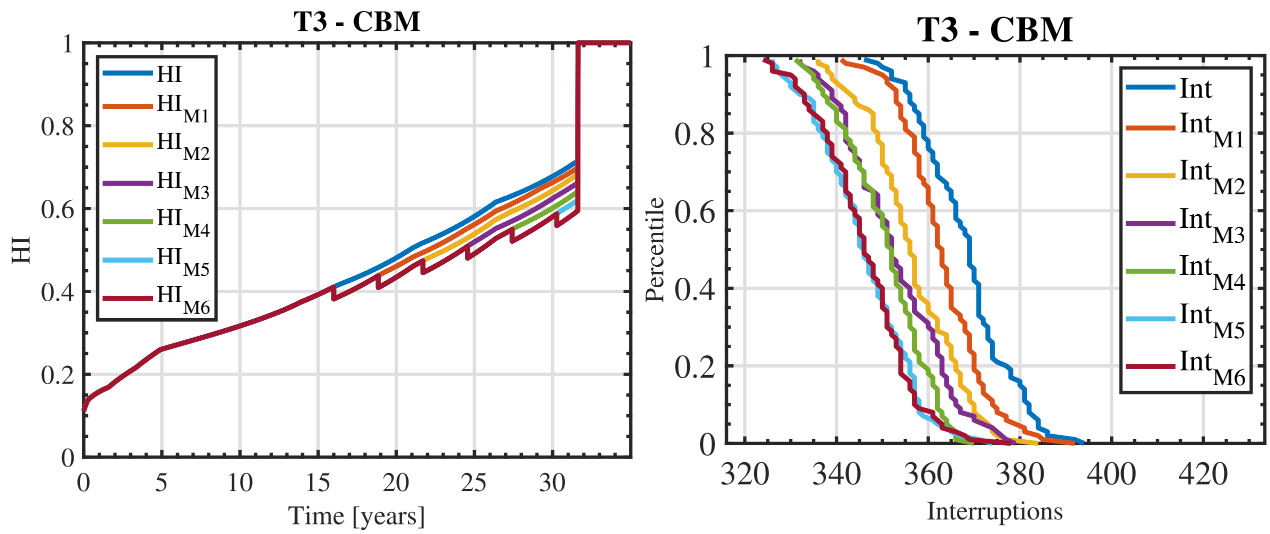


Figure 3.15.: HI and $\lambda(HI)$ for TBM - T3



(a) HI curves per maintenance for CBM - T3 (b) Interruptions expected per maintenance for CBM - T3

Figure 3.16.: CBM results for T3

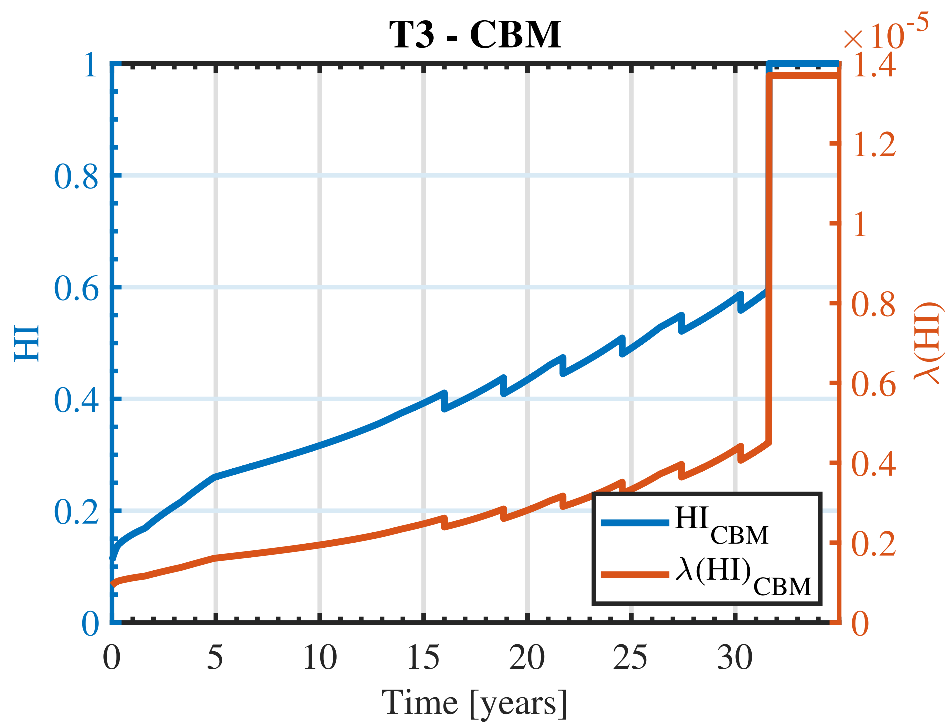
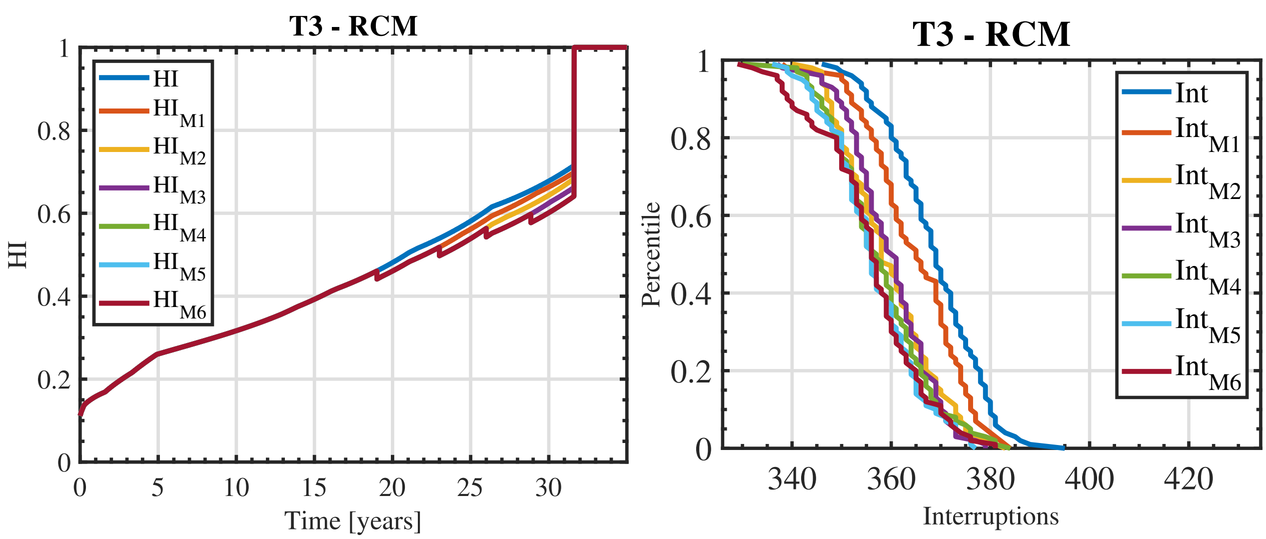


Figure 3.17.: HI and $\lambda(HI)$ for CBM - T3

Considering CBM for transformer T3, Fig. 3.16a presents the different curves generated after applying each maintenance. Since this transformer begins the simulation with a low value of HI, it achieves 0.4 of HI around year 16. Applying maintenance after year 16 seems to have a lower effect on the HI curves generated. Likewise, interruptions expected for each of these HI curves are presented in Fig. 3.16b.

Although there is a reduction of **24** interruptions between Int and Int_{M6}, this reduction is lower than obtained applying TBM. In addition, according to Table 3.3, maintenances M4, M5 and M6 do not cause any effect in the transformer health condition, nor the expected interruptions. Therefore, for this transformer, applying CBM is not the best option, since last maintenances applied do not represent a high impact on the transformer.

Resulting HI curve for CBM is presented in Fig. 3.17, as $HI_{CBM} = HI_{M6}$.



(a) HI curves per maintenance for RCM - T3

(b) Interruptions expected per maintenance for RCM - T3

Figure 3.18.: RCM results for T3

With respect to RCM applied to T3, there is a similar result to CBM. According to the criteria chosen for RCM, first maintenance in this transformer is applied after 20 years of simulation. In this case, applying maintenances after 20 years may not have a significant impact on the transformer health condition. A total of 4 maintenances are applied. Curves generated for these maintenances applied are shown in Fig. 3.18a. Likewise, Fig. 3.18b presents the corresponding expected interruptions, where the maximum reduction between

Int and Int$_{M4}$ is **14**. This reduction is even lower than the cases of TBM and CBM, which implies that RCM is not the best strategy for this transformer. Resulting HI curve for RCM is presented in Fig. 3.19, as $HI_{RCM} = HI_{M4}$.

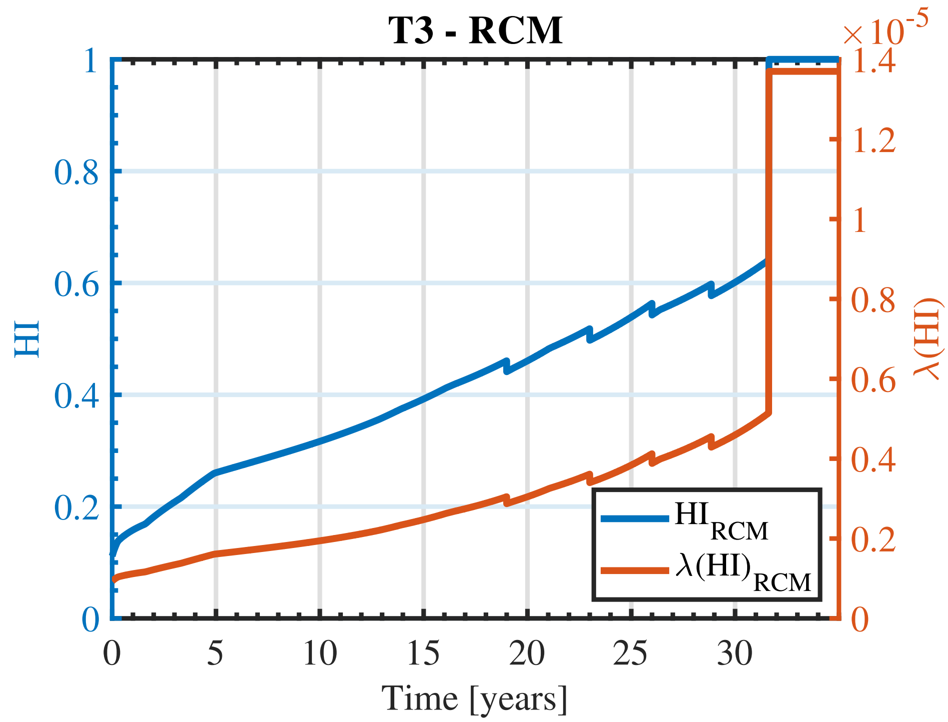


Figure 3.19.: HI and $\lambda(HI)$ for RCM - T3

Table 3.3.: Results summary for T3

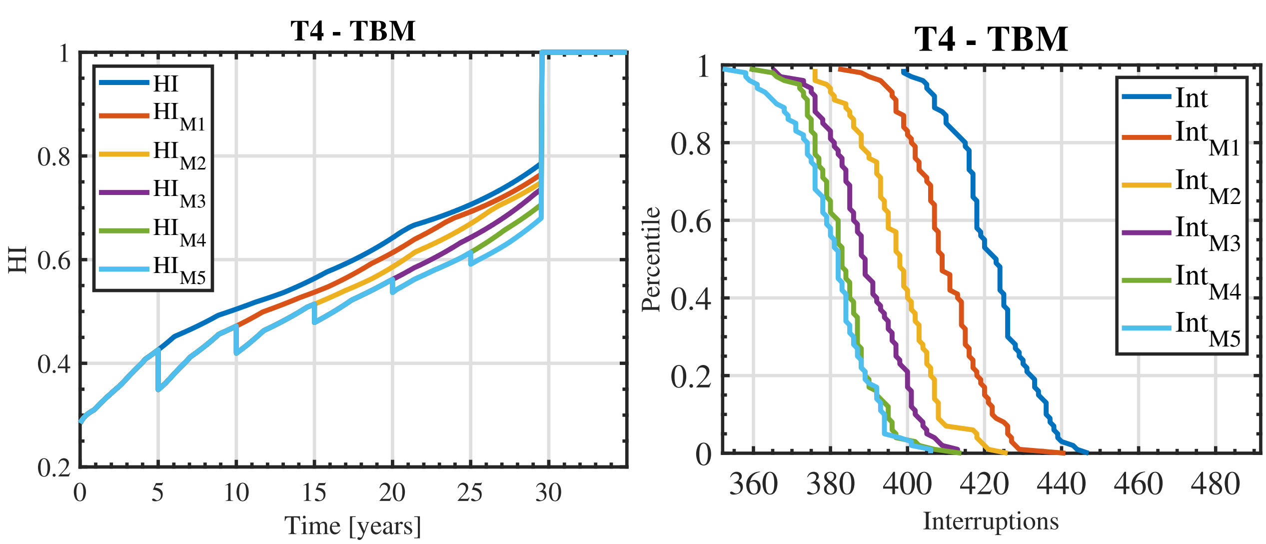
Reduction in expected interruptions with P_{50}	TBM	% TBM	CBM	% CBM	RCM	% RCM
Int - Int$_{M1}$	13	3,5	7	1,9	5	1,4
Int - Int$_{M2}$	20	5,4	14	3,8	12	3,3
Int - Int$_{M3}$	29	7,8	18	4,9	10	2,7
Int - Int$_{M4}$	31	8,4	18	4,9	13	3,5
Int - Int$_{M5}$	35	9,4	24	6,5	14	3,8
Int - Int$_{M6}$	37	10	24	6,5	14	3,8

Table 3.3 presents the summary results for T3 with all the maintenance schemes applied. As mentioned before, this is the case of a young transformer that ages slowly, therefore applying CBM or RCM do not represent noticeable effects on the transformer health condition.

Instead, unlike previous cases, TBM offers the best results for this transformer. When the simulation starts, this transformer presents a low value of HI. Therefore, when the first TBM maintenance is applied, this maintenance has a higher impact than the first maintenance applied by CBM when HI achieves 0.4 after 15 years of simulation. The application of TBM in this transformer when HI is low, can be considered as a preventive maintenance, since it prevents the transformer from an accelerated evolution of HI. Maximum reduction for TBM is **37** in expected interruptions, which is obtained after M5. This represents a 10% reduction of the total expected interruptions without maintenance In this case, M6 seems to be unnecessary.

3.2.4. Maintenance schemes applied to T4

For TBM applied to transformer T4, HI curves generated by every maintenance applied are shown in Fig. 3.20a. In total, 5 maintenances are applied in this case, each one representing a noticeable improvement in health condition transformer along its life. In the same way, Fig. 3.20b presents the interruptions expected for every of these HI curves. The reduction of expected interruptions between Int and Int$_{M5}$ is **40** taking as base percentile 0.5 as seen in Table 3.4. Interruptions reduction between last maintenances applied is barely appreciable. The decision of applying maintenance based on time after year 20 depends on the operator criterion. The resulting curve for this transformer is $HI_{TBM} = HI_{M5}$ as shown in Fig. 3.21.



(a) HI curves per maintenance for TBM - T4

(b) Interruptions expected per maintenance for TBM - T4

Figure 3.20.: TBM results for T4

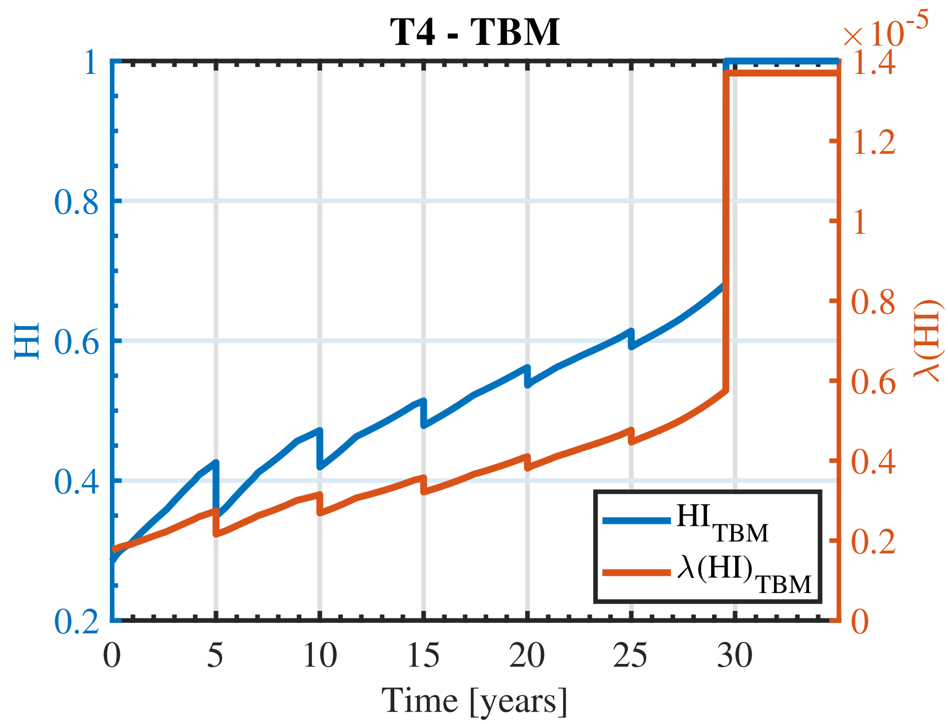
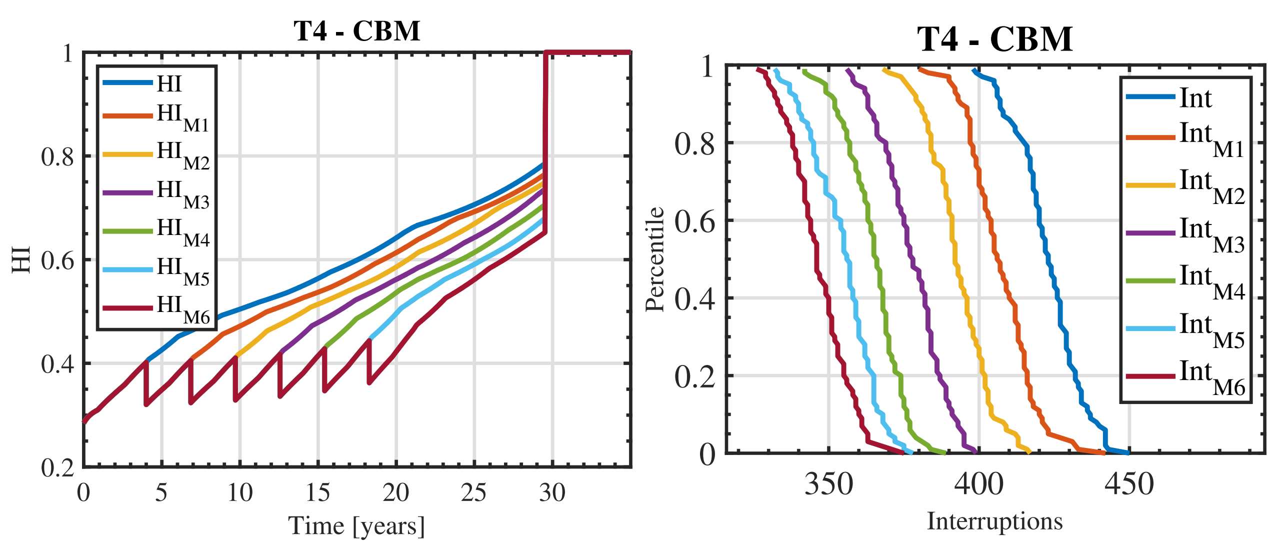


Figure 3.21.: HI and $\lambda(HI)$ for TBM - T4



(a) HI curves per maintenance for CBM - T4

(b) Interruptions expected per maintenance for CBM - T4

Figure 3.22.: CBM results for T4

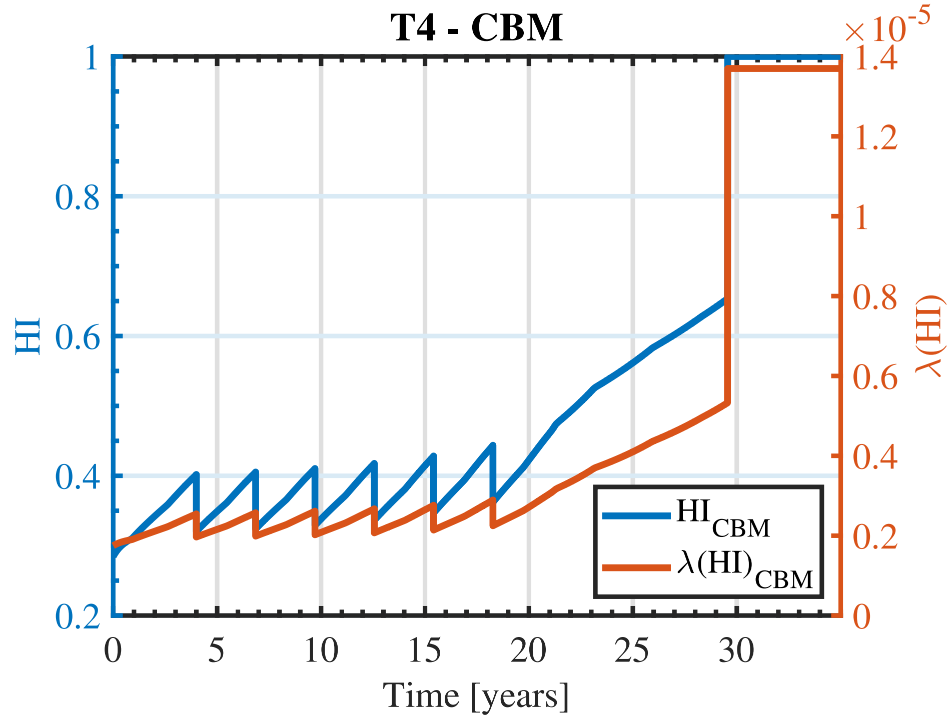


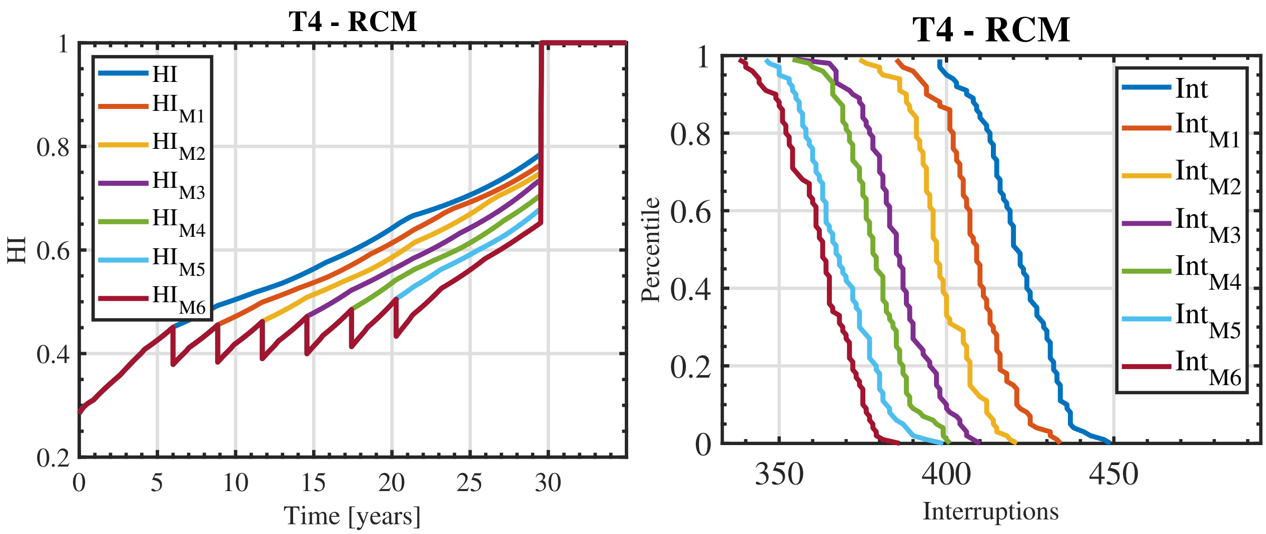
Figure 3.23.: HI and $\lambda(HI)$ for CBM - T4

Regarding CBM applied to transformer T4, this transformer has a increasing HI gradient since the beginning of the simulation. Due to this, the maintenance application starts around year 4. The high gradient evolution of its indices is reflected in the HI curves generated per maintenance. These curves are shown in Fig. 3.22a. Likewise, the impact of these transformers is reflected in Fig. 3.22b, where the difference between Int and Int$_{M6}$ is **76**. This reduction is considerably higher than for TBM case.

Resulting HI curve for CBM is presented in Fig. 3.23, as $HI_{CBM} = HI_{M6}$.

Evaluating RCM for transformer T4, in Fig. 3.24a it is possible to observe that 6 maintenances were applied starting in year 9 until year 24. In this case, after every maintenance, impact on transformer health condition is appreciable. However, a better impact could have been observed if first maintenance were applied before year 5, as seen in CBM. Figure 3.24b presents the corresponding expected interruptions. It is noticeable that there is a reduction of **59** in expected interruptions between curve Int and curve Int$_{M6}$.

According to Fig. 3.25, resulting HI curve for RCM is $HI_{RCM} = HI_{M6}$.



(a) HI curves per maintenance for RCM - T4

(b) Interruptions expected per maintenance for RCM - T4

Figure 3.24.: RCM results for T4

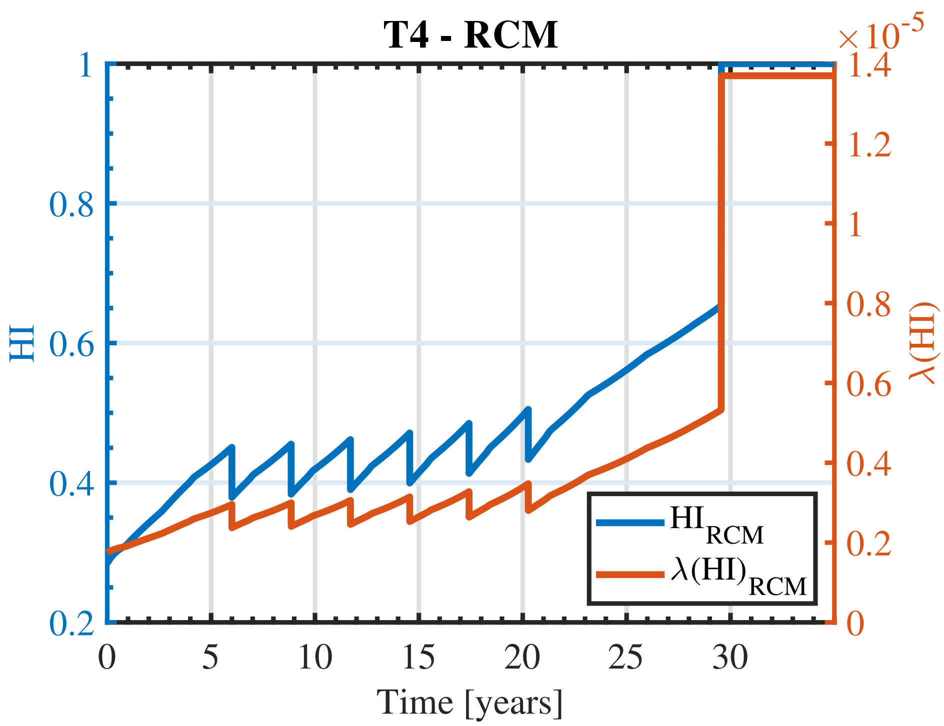


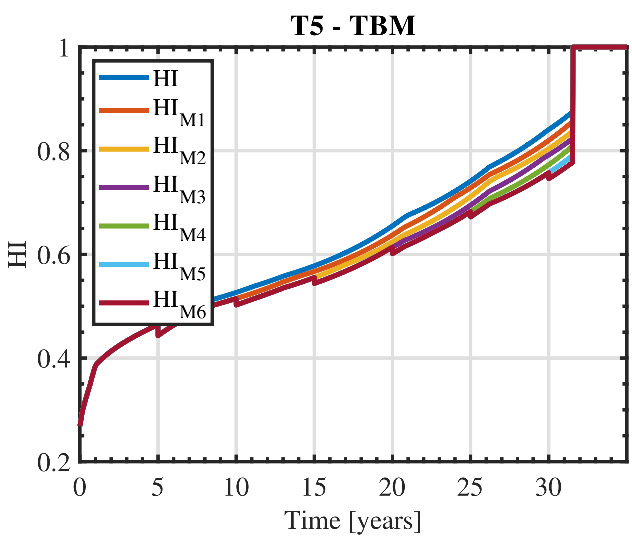
Figure 3.25.: HI and $\lambda(HI)$ for RCM - T4

Table 3.4 displays the results summary for T4. For all maintenance actions applied in every scheme, there seem to be a positive effect. Evidently, best scenario for T4 is CBM, since after M6, a total reduction of **76** expected interruptions is obtained, representing 18% of the total expected interruptions with respect to the base case without maintenance. TBM and RCM also can offer good results for assessing this transformer.

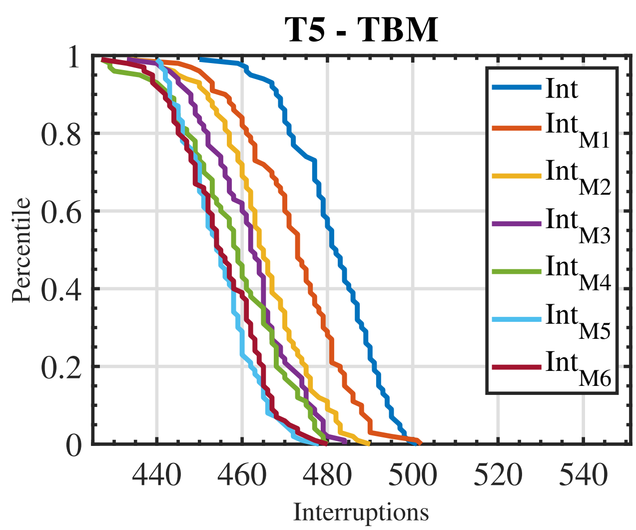
Table 3.4.: Results summary for T4

Reduction in expected interruptions with P_{50}	TBM	% TBM	CBM	% CBM	RCM	% RCM
Int - Int$_{M1}$	13	3,1	16	3,8	13	3,1
Int - Int$_{M2}$	24	5,7	30	7,1	25	5,9
Int - Int$_{M3}$	33	7,8	44	10,4	37	8,8
Int - Int$_{M4}$	39	9,2	56	13,2	44	10,5
Int - Int$_{M5}$	40	9,5	66	15,6	55	13,1
Int - Int$_{M6}$	-	-	76	18	59	14

3.2.5. Maintenance schemes applied to T5



(a) HI curves per maintenance for TBM - T5



(b) Interruptions expected per maintenance for TBM - T5

Figure 3.26.: TBM results for T5

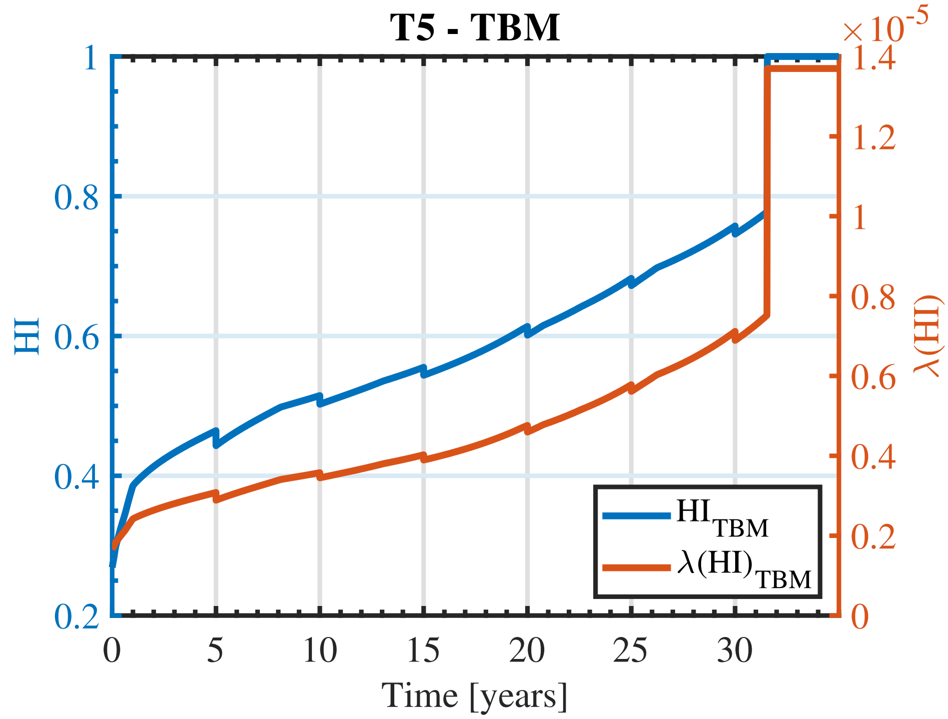
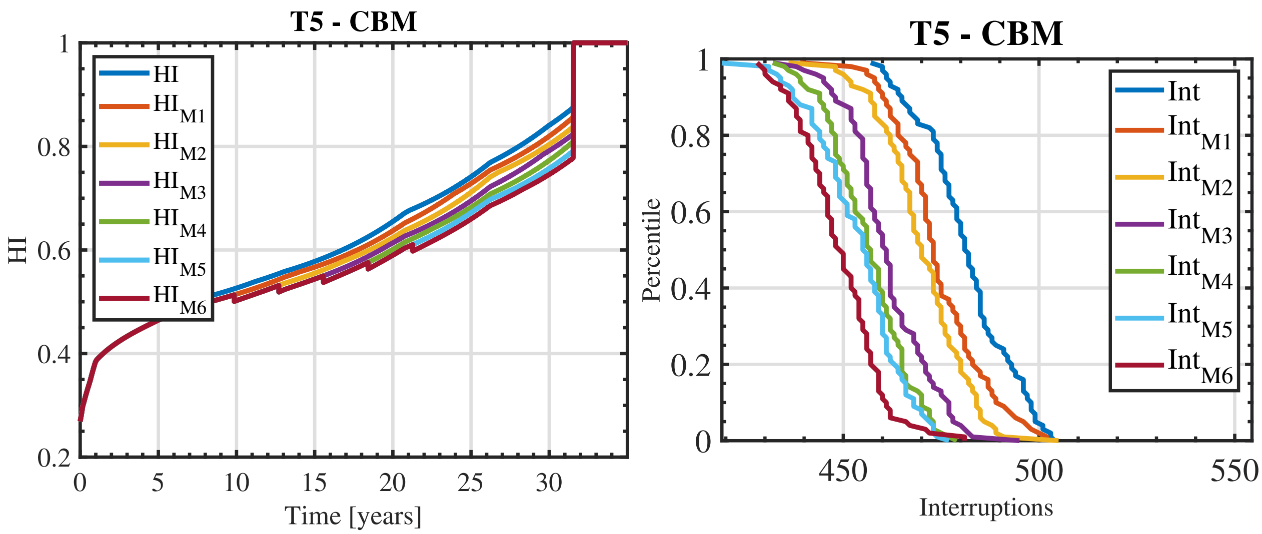


Figure 3.27.: HI and $\lambda(HI)$ for TBM - T5

Finally, for TBM to transformer T5, 6 maintenances were applied. The curves generated per maintenance are shown in Fig. 3.26a. In this case, the accelerated evolution of individual indices presented in Fig. 2.9 does not allow a notable effect of each maintenance. Figure 3.26b shows the expected interruptions for every HI curve. In this case, the reduction in expected interruptions between Int and Int_{M6} is **28** according to Table 3.5. However, it is possible to observe that maintenances M5 and M6 do not represent a considerable reduction of expected interruptions. Applying maintenances after year 20 depends on the operator criteria. According to Fig. 3.26a, resulting curve for T5 is $HI_{TBM} = HI_{M6}$.

With respect to CBM T5, although this transformer achieves a health condition of $0,4$ around year 1, the gradient keeps constant along several years, therefore the first maintenance is applied around year 6. From these curves generated per maintenance shown in Fig. 3.28a, it is possible to observe that the lasts maintenances do not represent a high reduction in HI. In the same way, in the expected interruptions per each curve, it is possible to observe that maintenances M4, M5 and M6 present a barely noticeable impact on the reduction of expected interruptions as shown in Fig. 3.28b. Being **33** the reduction of expected interruptions between Int and Int_{M6} according to Table 3.5. This reduction is hardly higher than TBM. Resulting HI curve for CBM-T5 is presented in Fig. 3.29.



(a) HI curves per maintenance for CBM - T5 (b) Interruptions expected per maintenance for CBM - T5

Figure 3.28.: CBM results for T5

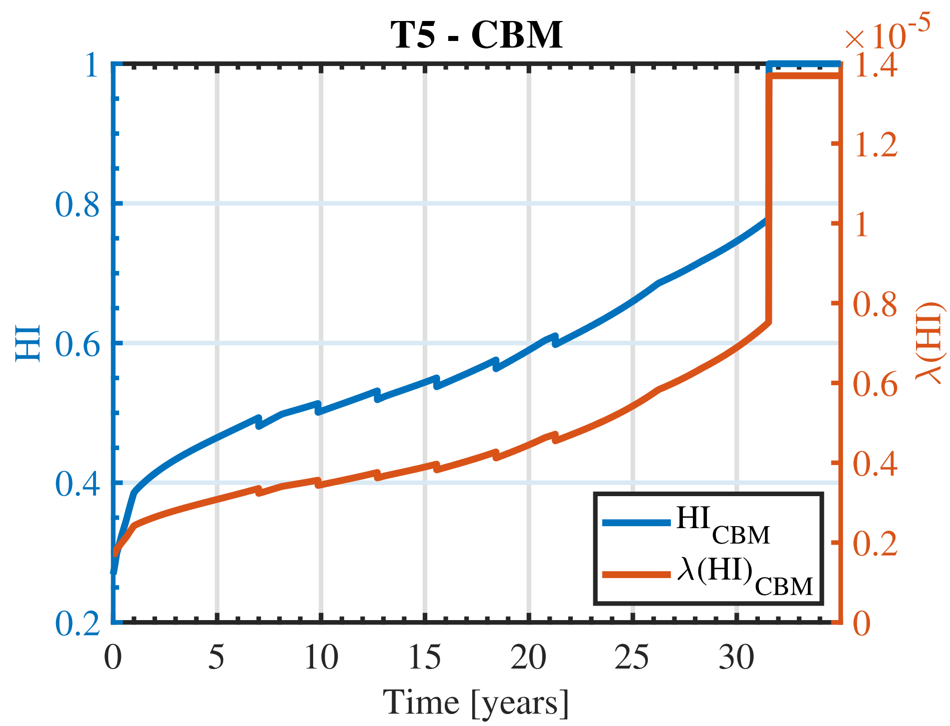
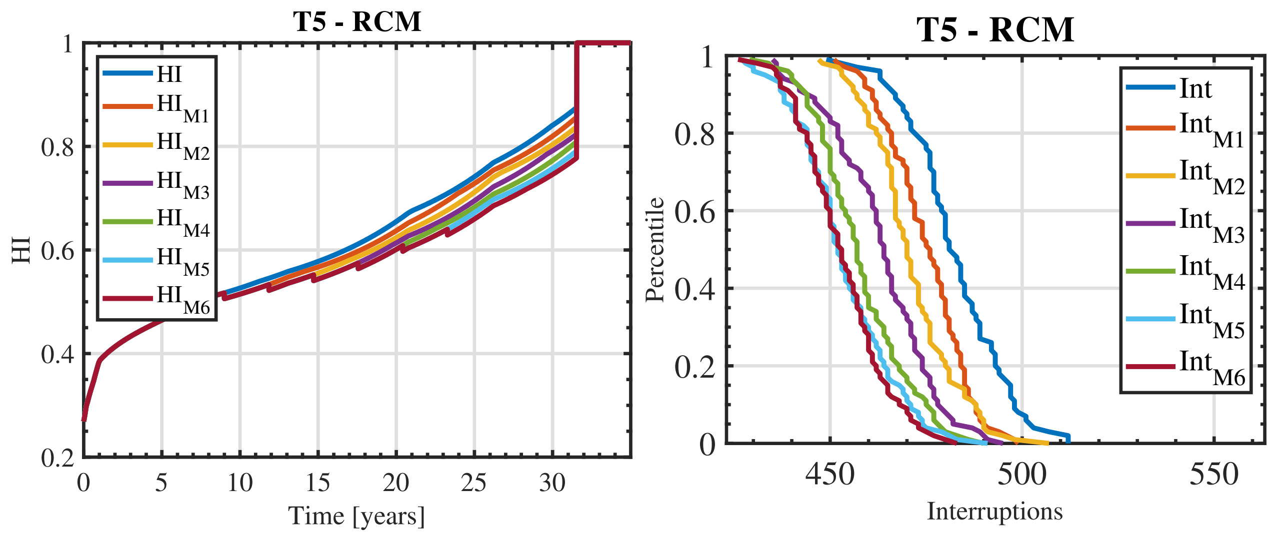


Figure 3.29.: HI and $\lambda(HI)$ for CBM - T5



(a) HI curves per maintenance for RCM - T5

(b) Interruptions expected per maintenance for RCM - T5

Figure 3.30.: RCM results for T5

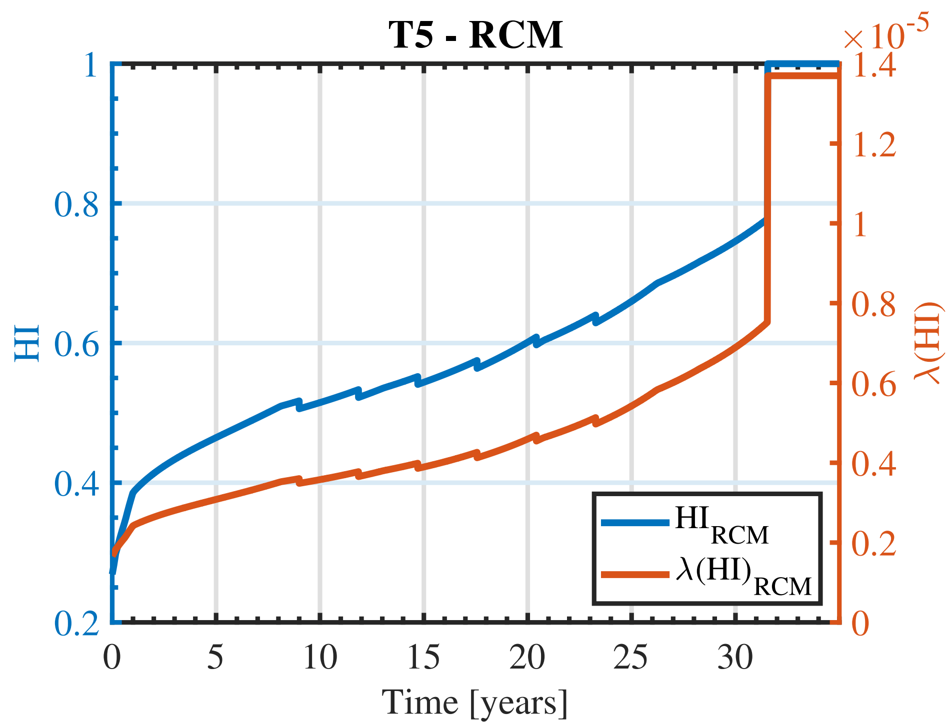


Figure 3.31.: HI and $\lambda(HI)$ for RCM - T5

In relation to RCM applied to T5, this case presents similar results to TBM and CBM. Since the health indices of this transformer evolve quickly in time, the effect of maintenance is not significant. HI curves generated for the 6 maintenances applied are shown in Fig. 3.31. The corresponding expected interruptions are presented in Fig. 3.30b, where the reduction between Int and Int$_{M6}$ is **30**. Same as before, the effect of the last maintenances is not significant either. In this case, TBM, CBM and RCM present similar results.

Table 3.5.: Results summary for T5

Reduction in expected interruptions with P_{50}	TBM	% TBM	CBM	% CBM	RCM	% RCM
Int - Int$_{M1}$	9	1,9	9	1,9	6	1,2
Int - Int$_{M2}$	17	3,5	12	2,5	12	2,5
Int - Int$_{M3}$	20	4,1	21	4,4	18	3,7
Int - Int$_{M4}$	23	4,8	25	5,2	25	5,2
Int - Int$_{M5}$	28	5,8	27	5,6	30	6,2
Int - Int$_{M6}$	27	5,6	33	6,9	29	6

Finally, observing maintenance results summary for T5 in Table 3.5, it is possible to observe that all maintenance schemes applied have similar results for this transformer. This is due to the accelerated evolution of this transformer health indices presented in Fig. 2.9. Therefore, all maintenances applied had a small impact in the resulting health condition. This can be explained by its indices accelerated evolution, which avoided a high impact in the maintenance effects. Maximum reduction in expected interruptions is obtained after M6 of CBM. However, it is pretty similar to the results of TBM and RCM.

Table 3.6 presents a summary of number expected interruptions for all cases considered before and for all transformers. Table 3.6 presents P_{10}, P_{50} and P_{90} in order to evaluate probability distributions of expected interruptions of the maintenance schemes applied. Being P_{10} the best scenario that can be observed, P_{90} the worst scenario, and P_{50} the expected scenario for all distributions considered.

With respect to T1, by applying TBM, the interruptions of the worst scenario ($Int_{TBM}(P_{90})$) are similar to the best scenario of interruptions without maintenance ($Int(P_{90})$). Likewise, with the worst scenarios of RCM ($Int_{RCM}(P_{90})$) and CBM ($Int_{CBM}(P_{90})$), it is possible to obtain better results than the case without maintenance ($Int(P_{90})$). This implies that any maintenance scheme applied to T1 can provide good results in comparison to not apply any maintenance scheme. Likewise, for T2, the analysis is similar. The worst scenarios for all maintenances schemes applied are better than the best scenario without any maintenance applied ($Int(P_{90})$).

For T3, worst scenarios of interruptions for TBM ($Int_{TBM}(P_{90})$) and ($Int_{CBM}(P_{90})$) are comparable to the best interruptions scenario without maintenance ($Int(P_{90})$). However, for RCM the worst scenario ($Int_{RCM}(P_{90})$) is similar to the median of the case without maintenance ($Int(P_{50})$), which implies again that RCM is not recommended for T3.

For T4, sames as T2, worst scenarios for all maintenance schemes are considerably better taking into account the best scenario of interruptions expected without maintenance ($Int(P_{90})$). Yet, CBM provides the highest reduction in expected interruptions.

With respect to T5, worst scenarios in interruptions of all maintenance schemes provide similar results to the median without maintenance ($Int(P_{50})$). This reduction is less significant than for the rest of the transformers. Yet, it represents an improvement in the health condition management of the transformer.

Table 3.6.: Summary of expected interruptions per maintenance and per percentile for all transformers

Number of expected interruptions per percentile		T1	T2	T3	T4	T5
No Maintenance	$Int(P_{10})$	367	422	358	410	466
	$Int(P_{50})$	384	436	370	422	482
	$Int(P_{90})$	397	449	384	435	500
TBM	$Int_{TBM}(P_{10})$	350	378	321	366	442
	$Int_{TBM}(P_{50})$	363	391	333	382	455
	$Int_{TBM}(P_{90})$	374	405	345	394	467
CBM	$Int_{CBM}(P_{10})$	326	370	333	333	436
	$Int_{CBM}(P_{50})$	338	383	346	346	449
	$Int_{CBM}(P_{90})$	349	396	357	360	461
RCM	$Int_{RCM}(P_{10})$	333	384	339	349	440
	$Int_{RCM}(P_{50})$	345	393	356	363	453
	$Int_{RCM}(P_{90})$	358	406	370	375	468

3.2.6. ENS analysis per maintenance for sample transformers

In order to appreciate the results of maintenance schemes previously simulated, the interruptions expected for each maintenance are used in order to estimate the corresponding cost of ENS. In this case the cost of ENS was calculated for a $MTTR = 336h$ and with the regulation price from Table 3.7.

Table 3.7.: Constants considered for ENS.

Constants	
MMTR	336h
CRO	≈1100 $COP

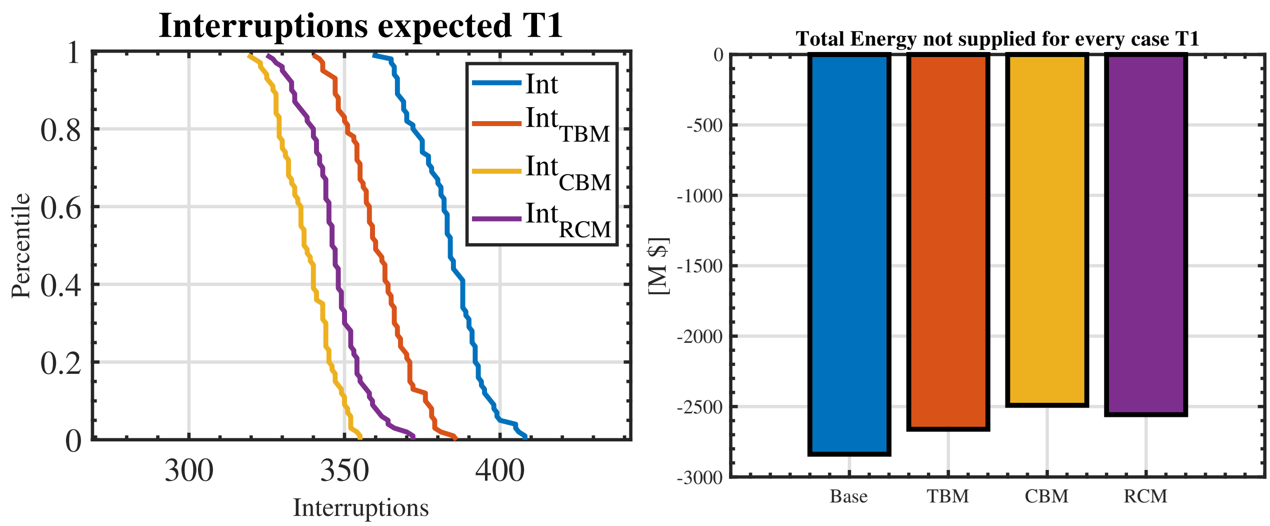
Table 3.8 presents the corresponding results of cost of ENS according to the expected interruptions for every maintenance applied to all transformers samples.

Table 3.8.: ENS resulting from P_{50} of expected interruptions per maintenances scheme

ENS with P_{50}	T1	T2	T3	T4	T5
$ENS(Int)$ [$M]	-2838,52	-14503,10	-5470,08	-8734,38	-16033,24
$ENS(Int_{TBM})$ [$M]	-2661,12	-12972,96	-4908,28	-7906,48	-15068,59
$ENS(Int_{CBM})$ [$M]	-2491,10	-12773,37	-5130,04	-7161,36	-15035,32
$ENS(Int_{RCM})$ [$M]	-2557,63	-13106,01	-5263,10	-7471,83	-15068,59

Figure 3.32a presents distributions of expected interruptions for T1 without maintenance and with maintenance schemes applied in Section 3.2. Here, it is noticeable the difference between the different maintenance schemes and the base case without maintenance.

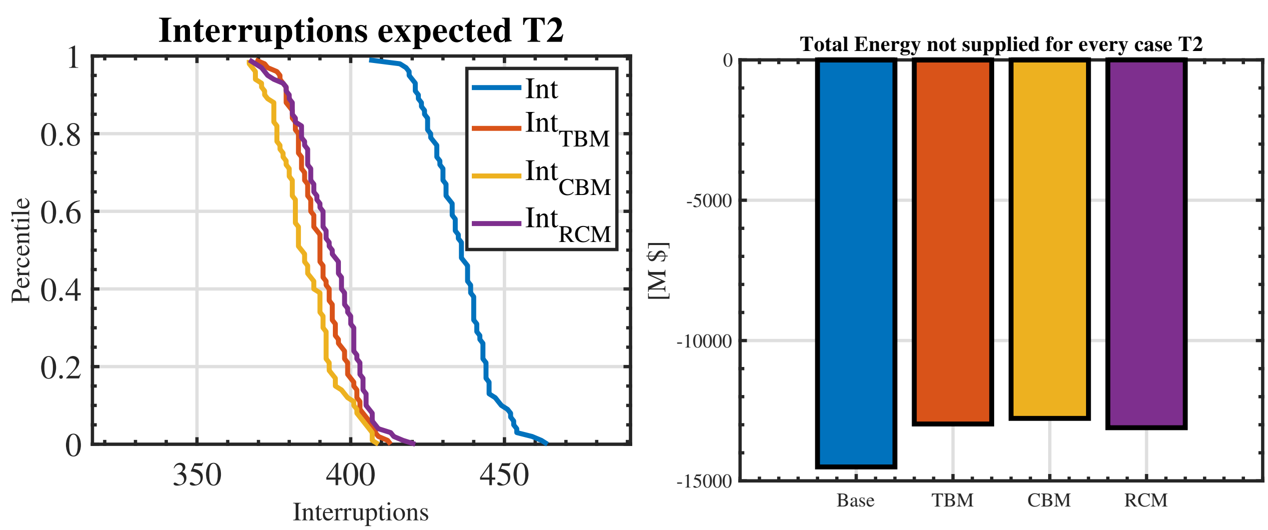
Likewise, Fig. 3.32b shows ENS calculated for the base case, which is interruptions of $\lambda(HI)$ without maintenance. It also presents ENS per maintenance simulated taking into account $\lambda(HI)$ of the resulting HI curves (HI_{TBM}, HI_{CBM} and HI_{RCM}). The reduction in cost for CBM is around $347M with respect to the no maintenance ENS according to Table 3.8.



(a) Expected interruptions per maintenance scheme for T1

(b) ENS per maintenance scheme for T1

Figure 3.32.: Expected interruptions and ENS per maintenance scheme for T1



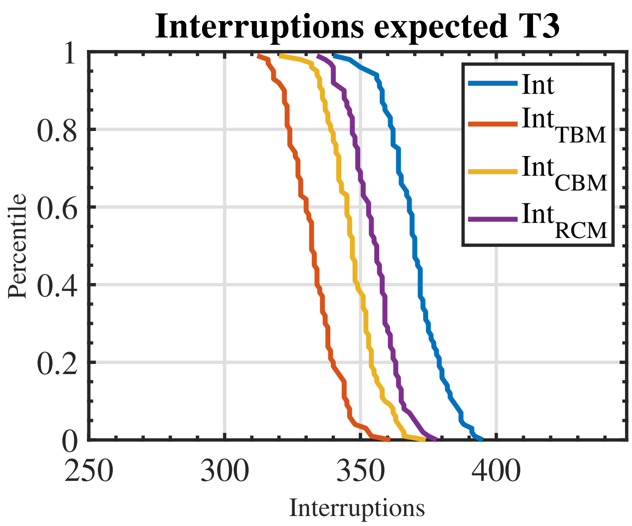
(a) Expected interruptions per maintenance scheme for T2

(b) ENS per maintenance scheme for T2

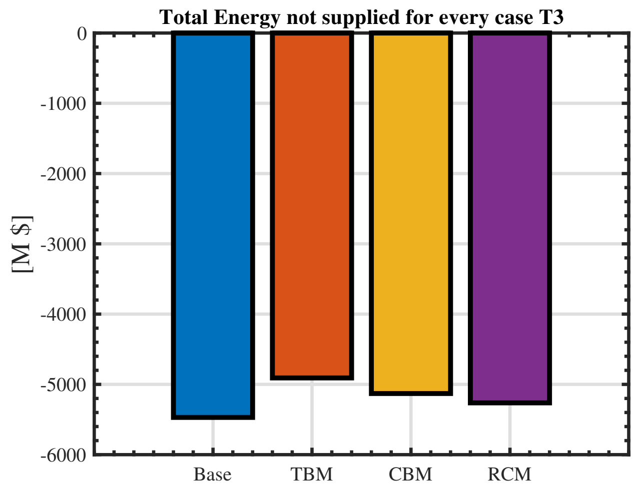
Figure 3.33.: Expected interruptions and ENS per maintenance scheme for T2

In Fig. 3.33a it is possible to observe the variation in expected interruptions for the different maintenance schemes applied to T2. Besides, Fig. 3.33b shows ENS calculated for $\lambda(HI)$

without maintenance. It also presents ENS per maintenance scheme simulated. Reduction in costs of ENS for the CBM scenario is around $1729M with respect to the case without maintenance as seen in Table 3.8.

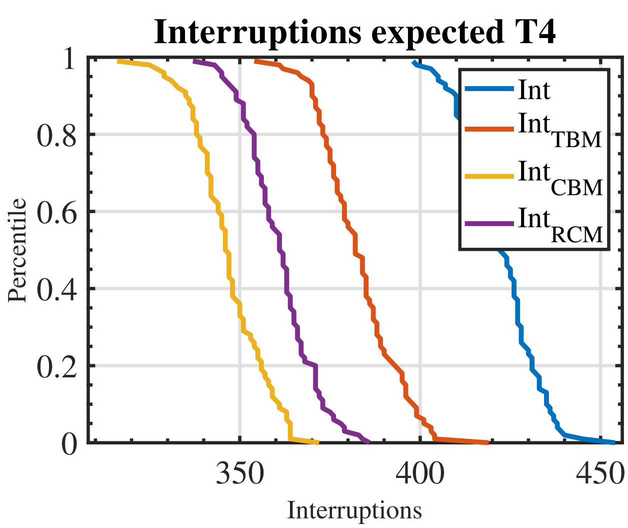


(a) Expected interruptions per maintenance scheme for T3

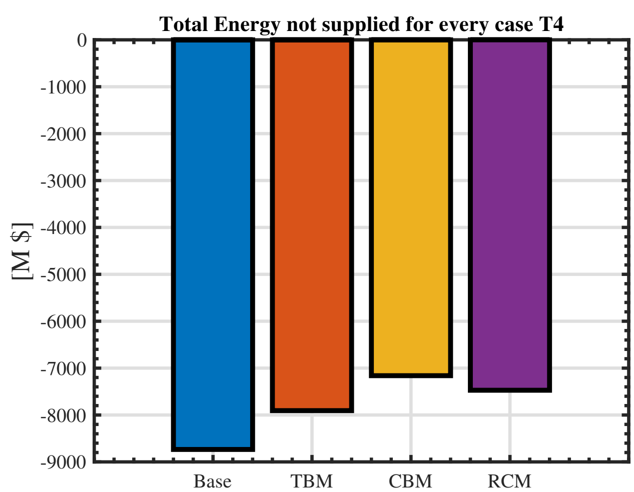


(b) ENS per maintenance scheme for T3

Figure 3.34.: Expected interruptions and ENS per maintenance scheme for T3



(a) Expected interruptions per maintenance scheme for T4

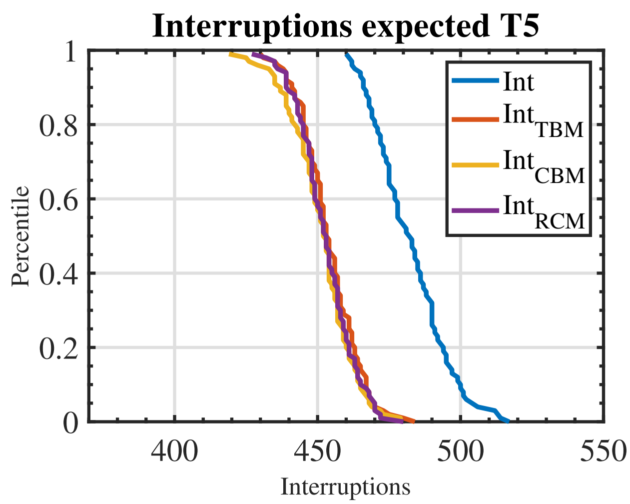


(b) ENS per maintenance scheme for T4

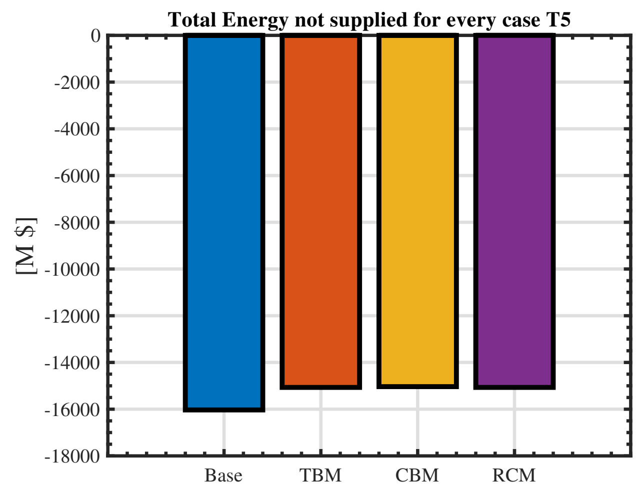
Figure 3.35.: Expected interruptions and ENS per maintenance scheme for T4

Figure 3.34a presents the distribution of expected interruptions per maintenance scheme. In the same way, Fig. 3.34b shows ENS calculated for the base case and also ENS per maintenance. The reduction in cost by applying TBM is around \$561M with respect to the case without maintenance, according to Table 3.8.

Besides, Fig. 3.35a and Fig. 3.35b present expected interruptions and ENS per maintenance obtained for T4. The reduction in cost by ENS for the best scenario is CBM with around \$1573M as presented with respect to the case without maintenance in Table 3.8.



(a) Expected interruptions per maintenance scheme for T5



(b) ENS per maintenance scheme for T5

Figure 3.36.: Expected interruptions and ENS per maintenance scheme for T5

Finally, Fig. 3.36a confirms the barely appreciable difference between expected interruptions distribution for all maintenance schemes. In the same way, reduction in cost for ENS is around \$1000M for every case with respect to the case without maintenance, according to Table 3.8.

Conclusions

- From the experience of this research, it is possible to conclude that concepts of TBM, CBM and RCM are widely open to the criteria of the operator. Therefore, for evaluating these schemes, it was necessary to establish different conditions and criteria.

- By the application of TBM and RCM for in all sample transformers, a pattern was observed with respect to the application of maintenances in years 25 and 30. In all transformers, maintenances applied after year 20, tend to not provide significant impact in the reduction of interruptions. Hence, it is possible to conclude that maintenances applied after year 20, are to be worthless, because of the advanced health indices evolution after this year, such as DGA, DS, IFT and $\%Sat$.

- With respect to TBM scheme, it was found that it is not the best scenario when the asset has an advanced health condition, since the effects of applying maintenance do not have a high impact in the transformer HI and expected interruptions. Instead, if the transformer was commissioned recently or presents 0.2 of HI, this maintenance is capable of providing good results, which was the case of T3.

- It was corroborated that CBM is the maintenance that presents better results for most of the sample transformers. Yet, it is possible to conclude that this scheme can present disadvantages with respect to TBM when the asset is new. Taking into account that an average transformer may achieve a 0.4 of HI after 15 or 20 years of operation, applying a maintenance after this years cannot provide significant results.

- For T5, it was found that there is no distinction in applying the different maintenance schemes. Since its health indices evolve so quickly, the impact of applying different maintenance is not observable, yet there is improvement.

- In general, it is possible to conclude that the maintenance schemes simulated provide different significant results, yet the best scenario for each transformer, depends on its HI evolution, and the criteria chosen for applying the maintenances.

- From the analysis of expected interruptions for all maintenances schemes, it was possible to observe that the worst scenario of expected interruptions is always better than the case without maintenance. According to these observations, it is possible to conclude that applying maintenance provides improvements in expected interruptions and is always recommended to apply maintenance. Deciding on the scheme or moment to apply the maintenance depends on the criteria and therefore, can give different results, yet promising results.

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4. Proposed model for managing power transformers

Summary

Finally, the proposed model for applying maintenance in power transformers is introduced in this chapter. In this part, the concepts of risk, cost and benefit are gathered for presenting the maintenance model proposed. The proposed model will be implemented in the sample transformers taking into account HI simulation from Chapter 2.

Introduction

The methodology for managing a power transformer presented here aims to connect the three variables proposed for the maintenance model: risk, cost and benefit. Therefore, it is necessary to begin with the analysis of health condition. As presented in Chapter 2, this condition depends on the tests and analysis performed to the different parts of the asset. Most of the tests performed on the transformers are focused on the tank and the active parts. From this condition, and the other concepts, the maintenance model proposed is presented at the end of the chapter. This model aims to find the optimal moments when a maintenance is feasible taking into account risk and cost.

4.1. Costs considered by regulation

Inside the cost-benefit model it is important to consider different factors related to the regulation system and the operator requirements.

A few years ago, ISO 55000 [1] was updated from PAS 55 [2] and presented a new overview of asset management and definitions. The series of ISO 55000 for Asset management comprises 3 standards: ISO 55000 [1], ISO 55001 [3] and ISO 55002 [4]. The second standard is focused on management systems, and the last standard presents guidelines for the application of management systems.

In 2018 in Colombia, the CREG elaborated a new decree [5] that comprises several of the politics and asset management theory of ISO 55000 and PAS 55. Since then, it is mandatory for all operators in Colombia to develop their own asset management plan and implement it. In some cases, it is called Strategic Asset Management Planning ($SAMP$). As a result, this decree started a process for implementing true asset management strategies according to the actual regulation.

According to the ISO 55000 [1] and the CREG 015 [5], there are different costs to take into account when managing an asset such as the power transformer. First of all, the transformer is one of the most critic assets for most operators. It represents a high investment, and the compensation costs related to this asset are usually the highest. In addition, power transformer and shunt bank capacitors are the only assets that pay for energy not supplied (ENS) when they are out of service.

Investment costs : the costs associated to investment are divided into: cost of the asset, installation, commissioning and decommissioning. However, the CREG regulation [5] recognizes a cost of installation, C_{ins}, and a cost for every MVA installed, C_{MVA}, according to Eq. (4.1). In this cost, decommissioning is not recognized and depends directly on the operator. Then, this regulation presents tables with these costs established for every constructive unit (UC), which are the real costs that the CREG acknowledges for every asset.

$$C_{inv} = C_{ins} + S \cdot C_{MVA} \tag{4.1}$$

Maintenance costs : the maintenance costs are difficult to estimate and depend mostly on the type of maintenance. The CREG recognises two types of maintenance: Major maintenance and minor maintenance. The Major one can be executed within an interval of 6 years, while the minor one can be executed every year inside a calendar previously scheduled. This type of maintenance also has a maximum of hours to be executed. If the assets exceed this maximum of unavailability during maintenance, then there is an adjustment for these hours.

$$C_M = 0.03 \cdot C_{investment} \tag{4.2}$$

Generally, a Major maintenance is calculated as a percentage of the investment cost, C_{Inv} as shown in Eq. (4.2).

Costs by No operation : the costs related to No operation are usually the highest because of the compensations payed by the operators. The costs by No operation are divided into: cost by unavailability and cost by ENS.

The unavailability cost depends on the whole amount of assets and the network configuration of the operator, because when a transformer is out of operation, then the rest of assets must compensate the outcome. Therefore, this costs is not contemplated for the model.

The cost by Energy not supplied (ENS) is paid by the transformer when is disconnected without prior notice, that means, because of a failure. This cost corresponds to the ENS along the hours out of service with the regulation price. In other cases, if the asset is not connected because it is not needed in the substation, it also pays ENS. Then, all assets are intended to be operating while they are remunerated by the CREG .

Cost by ENS is calculated with the power of the asset P_{TR}, the hours of unavailability or out of services h_{OS} and the regulation price CRO as seen in Eq. (4.3) [5].

$$C_{ENS} = P_{TR} \cdot h_{OS} \cdot CRO \tag{4.3}$$

Criticality cost : This type of cost is not derived from regulation [5]. This is a type of cost considered by the operator. This cost represents: how much does it cost for the operator when an asset fails? [6] It applies to all kind of assets, but generally, this costs is representative for high investment assets. Criticality cost depends on:

- The operator network configuration
- Amount of assets inside the substation, and its configuration
- The demand at the moment of the possible failure
- The existence of replacement
- Amount of load transferable

Therefore, criticality is an estimated cost of how much is the cost to re-establish normal conditions and how much the operator losses because of the asset failure, based on the experience of ENEL-Codensa. For example, if a power transformer fails and its demand can not be supplied by another transformer in the substation, then this cost may be higher. In contrast, if the load can be supplied by another transformer in the same substation, then the criticality cost can be lower. According to experts of ENEL-Codensa, this value is evaluated yearly depend the asset characteristics and substation configuration.

4.1.1. Adjustment for the new regulation

The regulation interposed by the CREG changes the whole panorama of how operators invest in assets in Colombia. Consequently, the new regulation includes some adjustments for the existing assets in the electrical system.

One of the first adjustment is the remuneration time. Right before the new regulation, all assets were remunerated constantly every year. No installation date was considered for remunerating as long as they keep reliability indices under some limits. Then, it is a common case to find multiple assets in substations that are not fully loaded.

New regulation presents a table with the period of remuneration for every asset in high voltage, as seen in Table 4.1. Moreover, new regulation presents two cut dates: 2008 and 2018. All assets installed before 2008 are considered as installed in 2008, hence at the date of the resolution, these assets will still be remunerated for some time additionally. On the contrary, assets installed after 2008 are considered to be installed in 2018, then they are still remunerated starting in 2018.

Table 4.1.: Economical life recognised for HV assets. (Taken from CREG 015 de 2018 [5])

Category	Asset	Life recognised [years]
1	Power transformer	35
2	Shut bank capacitors	35
3	Bays and switch-gear cells [1]	35
4	Communication and control equipment	10
5	Substation equipment	35
6	Other substation assets	45
7	Overhead lines	45
8	Underground lines	45
9	Lines equipment	-
10	Control centers	10

For example, the sample transformers considered for this research were all installed before 2008 according to Table 2.6. Since they all were installed before 2008, they are considered as installed in 2008. However, as the regulation starts in 2018, they have 25 years of remuneration left starting from 2018. If the case was the opposite, it means that they were considered installed in 2018, then their remuneration schemes are calculated for 35 years starting in 2018.

4.2. Proposed model

As a result of analyzing the different variables that affect a power transformer assessing, it is important to establish the a relationship model that correlates these variables in order to obtain a more accurate maintenance scheme. These variables will be used for establishing a Risk Model and a Cost-Benefit Model.

As mentioned before, the new regulation allows a majeur maintenance for the assets at least every 6 years. During the majeur maintenance the asset remains out of service but does not pay compensations. However, not all assets need to apply a maintenance every 6 year. The ideal is to obtain an optimal maintenance plan depending on the evolution, conditions and restrictions of the asset. Generally, this majeur maintenance includes actions such as: oil filtering, electric tests, maintenance in other parts connected to the power transformer (OLTC, bushings, temperature sensors, among others). Finding those moments in which the maintenance is needed is the purpose of maintenance model proposed.

Firstly, the proposed model starts with the health condition evolution of the sample transformers to be analyzed. From the health condition (HI), it is possible to obtain the failure rate $\lambda(HI)$ and the probability of failure, which is used to estimate the risk of failure of the asset. After risk is evaluated, it is used for evaluating the decision of applying a maintenance along with the variable of cost.

For evaluating these variables and finding when the decision of applying maintenance is feasible, fuzzy logic inferece is used. Along the years, the theory of Fuzzy Logic Control has emerged as an useful tool for different applications in research. This kind of control is based on the theory of Fuzzy Logic which comes from the concept of fuzzy combination. In a fuzzy combination, an element may belong or not to the combination, which are the two only available states. Applied to a variable, it is considered only two states also. By gathering an amount of variables related to each other and applying them to a Fuzzy Logic Control system, it is possible to find logically what is necessary to get to the best performance or optimal point. That is to say, this tool allows to evaluate an output from the different combinations of its input variables.

Fuzzy logic has been used for the assessment of non quantifiable variables such as those that are designated attributes as "good", "much" or "poor". For this research, Health Condition will not be evaluated through fuzzy logic inference, although there are some approaches for analyzing power transformers condition with fuzzy logic [7] [8]. Instead, this tool will be used for analyzing its possible effects on the transformer and when it is feasible to carry out actions for extending the transformer useful life. Therefore, as consequence of aging and, starting from the simulation of health condition (HI) and failure rate $\lambda(HI)$, the transformer assessment proposed has 2 subsystems: Risk and Cost-benefit.

Thus, by analyzing these variables based on the costs and profits obtained by the asset remuneration, it is possible to find those moments in which applying a majeur maintenance can be feasible.

4.2.1. Risk model

Beginning with the risk related to a transformer inside an electrical system, there are two kinds of risk involving this asset. The first kind of risk is related to the failure rate when the asset ages. Since there is a transformer health condition evolving constantly in time, if HI increases, so does the risk. The other kind of risk is associated with the fault itself. This risk related to the failure rate can have different levels of severity. Depending on the kind of fault, the transformer may be unavailable longer than expected [9]. The faults can be present in the internal parts of the transformer such as: core, tank and windings; or in the external parts: bushings, measurement system, etc. This kind of risk is evaluated through historical data of equipment failures. For this research this type of risk is not considered.

Table 4.2.: Matrix for evaluating Risk

Criticality / POF	Low	Medium	High
High > 0.7	M	H	H
Precaution > 0.5	M	M	H
Acceptable > 0.3	L	M	M
Low > 0.1	L	L	M

Therefore, the Risk model focuses in estimating failure risk, where according to the POF and the criticality (Cr), the level of Risk is determined [10]. These variables are analyzed yearly along the simulation time. With respect to the estimation of Criticality, as it was mentioned before, this cost does not depend on the regulation. It depends on the operator and substation characteristics. Hence, according to the experience by ENEL-Codensa, a value is estimated as a base cost of \$100M COP that can change depending on the evolution of HI. The interval for evaluating Cr is between 0 and \$200M COP, divided equally in 3 states: “Low”, “Medium” and “High” When HI presents a higher gradient, this means that the asset is getting more critical, then this value can increase. POF is obtained from HI as presented in Eq. (2.15).

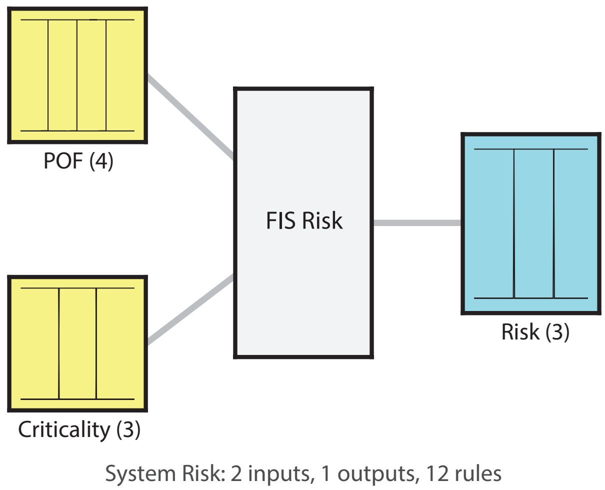


Figure 4.1.: FIS Risk model.

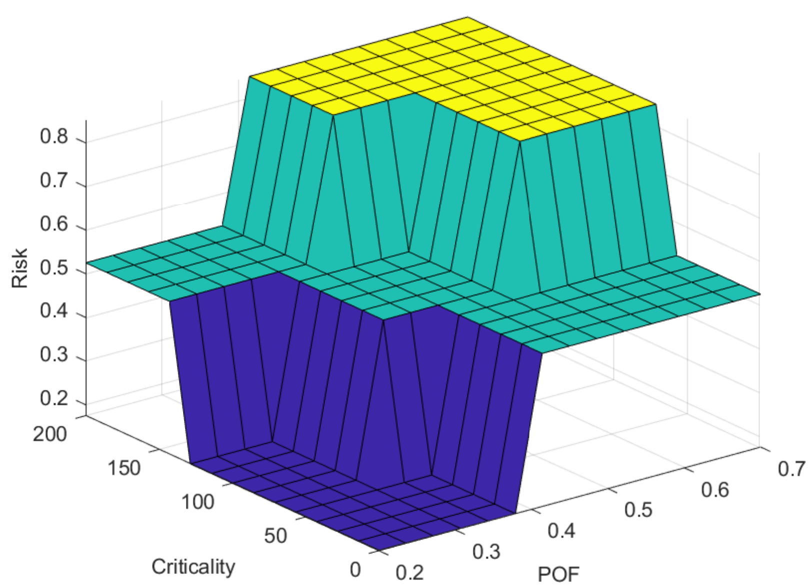


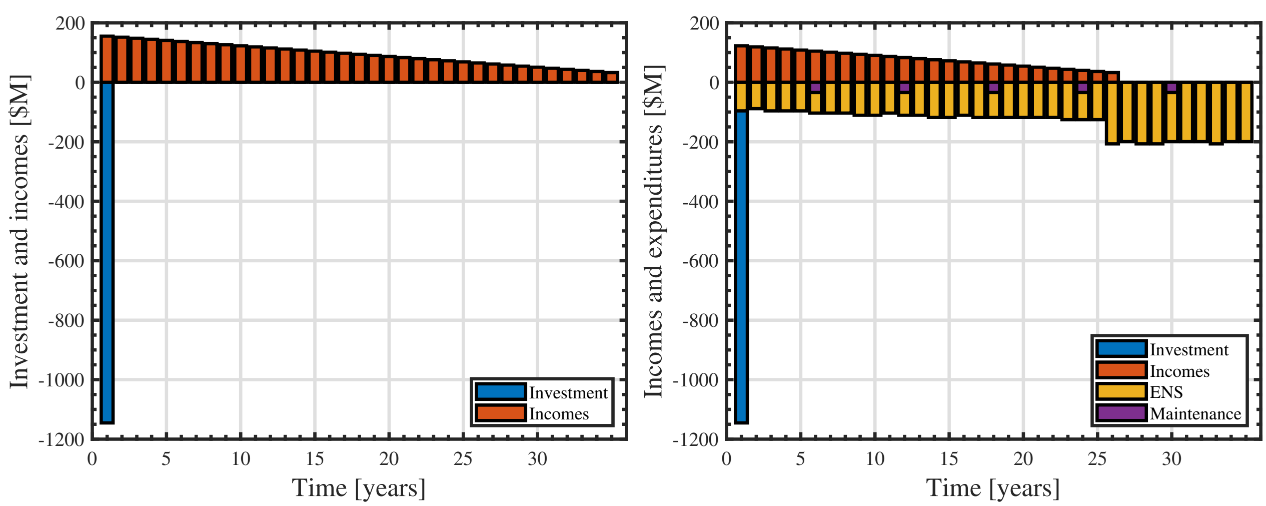
Figure 4.2.: Surface of FIS Risk model.

Probability of failure and Criticality are fuzzified in order to obtain Risk as presented in Table 4.2. The FIS model for evaluating risk is shown in Fig. 4.1. Then, a series of rules from the possible combinations of the membership function plots for both variables are formulated, and for every combination a fuzzy output variable is given [11] [12]. It is known as the FIS and is better represented through a surface such as shown in Fig. 4.2, where inputs are represented in X and Y axis, and the output, risk, is in the Z axis.

The rules that conform the surface presented in Fig. 4.2 generally are conditional, but there can be exceptions. For example, these rules have the following reasoning: If *POF* is "High" and *Criticality* is "High", then the *Risk* is "High", following the logic of Table 4.2.

4.2.2. Cost-benefit model

For this model, it is important to take into account the previous considered costs that apply to the economical life of a transformer. An average power transformer under rated conditions should have an operational life of 20 years approximately. However, most of electrical assets do not perform under rated conditions. That is to say, they generally can last more than 20 years. Before the change in regulation, all assets were remunerated yearly as long as the asset was operating. Therefore, some operators in Colombia invested in assets constantly in order to obtain higher incomes. Now, with new regulation [5], there is a limit of time to be remunerated, then operators must change the way they invest in assets.



(a) Remuneration plan for T1 by CREG 015

(b) Total costs for T1

Figure 4.3.: Costs considered for T1

According to the current regulation [5], the operator receives incomes that decrease in time. For example, Fig. 4.3a presents the remuneration plan for T1 if the asset would have been installed after 2008 according to the values presented in Table B.1. For this transformer, the remuneration plan starts with \$155.124.084 COP in year 1 and finishes with \$32.726.600 COP. The maximum benefit remuneration is obtained by the end of the remuneration plan, with a VPN value of \$2.528.300.000 COP, which is twice the investment.

In Fig. 4.3a, investment is presented in the first year, despite the fact that investment was made several years ago. The operator expects obtaining the best profit with the new remuneration plan. Any remuneration received before 2018 is not considered.

However, as the asset was installed before 2008, there are only 25 years of remuneration, starting with the income of year $11th$ \$119.124.824 COP in year 2018. The total income in VPN for this adjustment in the remuneration plan has a value of \$1.554.400.000 COP. This is presented in Fig. 4.3b, based on the values of Table B.1. In the case of a fatal failure in the asset in the firsts years of operation, the rest of remuneration payments are lost. Generally, a fatal failure in the first years of operation is unlikely for a new transformer, but with a high impact in the case of occurrence. Since the sample transformers are not new, the probability is higher. In addition, along the operation, the transformer failure rate is expected to increase, therefore ENS will also increase. Inevitably, in some point, expenditures will be higher than the incomes. In this case, after 25 years of operation, the power transformer is no longer remunerated. Therefore, the operator can only obtain the maximum benefit along the period of time in which the asset is remunerated. Remuneration plans for T2, T3, T4 and T5 are presented in Appendix B.

Table 4.3.: Matrix for evaluating Decision of applying a maintenance

Risk \ Cost	Low	Medium	High
High	M	H	H
Medium	L	M	H
Low	L	L	M

The FIS of this model is shown in Fig. 4.4. The output of this model is the final decision of applying a maintenance to the transformer taking into account the level of risk and the cost associated. From these variables, the 9 possible combinations can only result in two membership function plots of the output: *Yes* or *No* for the Decision. In brief, this model focuses the evaluation of costs related to the operation of the transformer and the maximum benefit by applying maintenance. Therefore, along with risk obtained before, the total costs associated to the transformer operation are the variables used for evaluating when maintenance is feasible for power transformers.

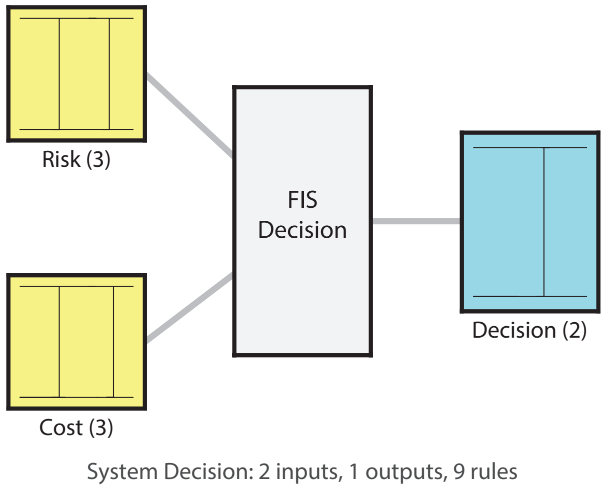


Figure 4.4.: FIS Decision model.

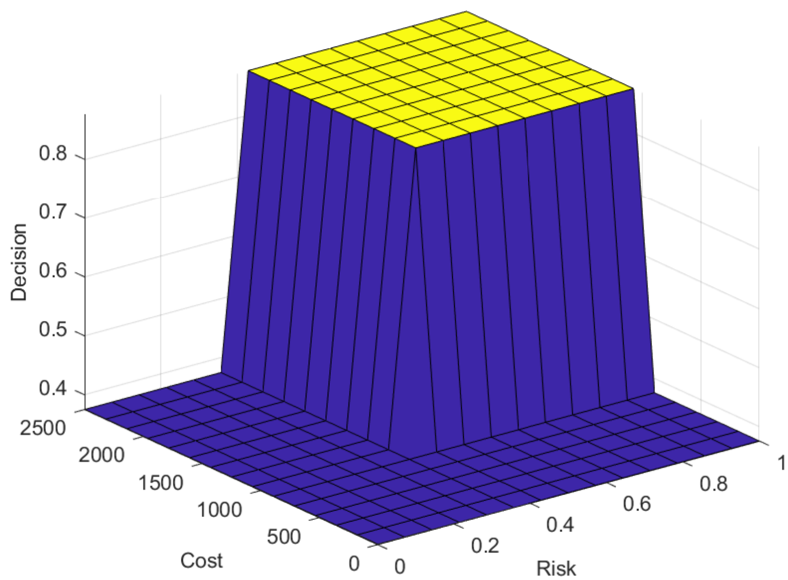


Figure 4.5.: Surface of FIS Decision model.

Cost will be fuzzified into 3 possibles stages according to their evolution in time [11] [8], just like Risk as seen in Table 4.3. The adjustment of these stages for cost depends on the transformer, since remuneration, maintenance cost and ENS depend on the transformer capacity and operation. For example, as seen in Fig. 4.5, a cost of 1500M\$ COP of lost by the transformer failure and a Risk of 0.8 give as a result a Decision around 1, which means that it is feasible applying maintenance. A cost of 500M\$ COP and a Risk of 0.2 give as a result a Decision around 0, which means not applying maintenance. Since the variables are fuzzied, different outputs between 0 and 1 are expected. In all cases, maintenance will be applied when decision output is higher than 0.5. With the possible combination of these variables, it is expected to find the moments when maintenance is feasible. The output of this model is the decision of applying maintenance. The FIS surface for this Model is shown in Fig. 4.5.

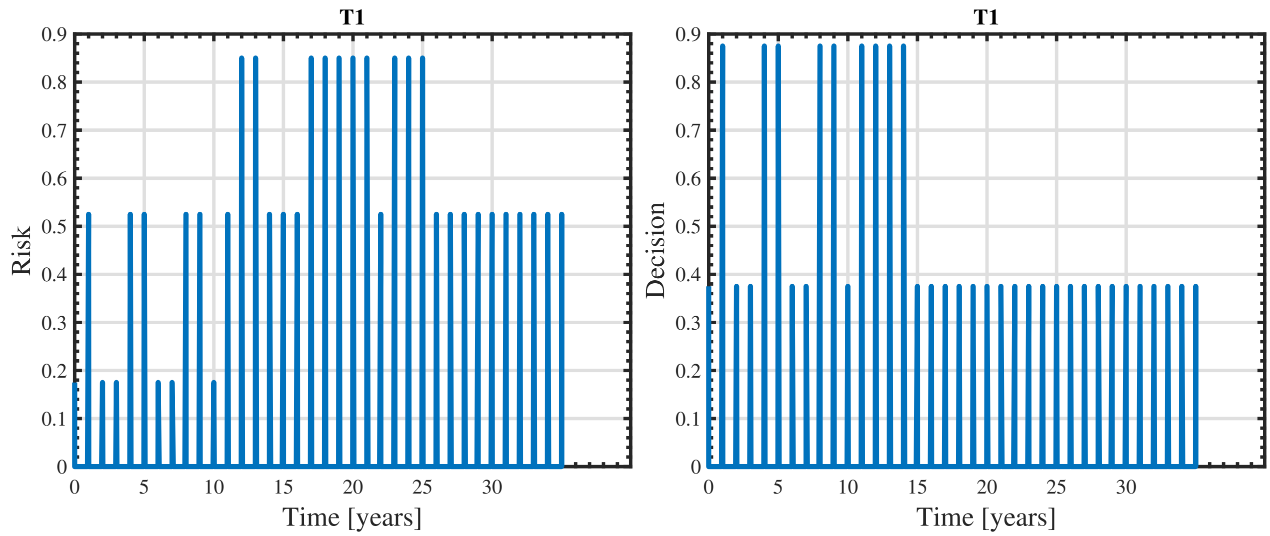
4.3. Implementing the proposed model

First, health condition simulation implemented in Section 2.4 is used here. Cost, risk and decision variables are presented here for sample transformers following methodology of Chapter 4. Risk is evaluated every year taking into account Cr and POF of the asset. These variables are inputs for the Risk FIS model, where rules crossed inputs to find the risk of the asset. Risk is expected to be a value between 0 and 1, where a value lower than 0.33 represents low risk, a value between 0.33 and 0.66 represents medium risk, and a value between 0.66 and 1 represents high risk.

Besides, Risk is one of the inputs for Decision FIS model. The other input is the costs related to the transformer. First, the incomes received by the asset remuneration. Second, the ENS cost generated by expected interruptions. And finally, maintenance costs associated. Scale of costs are defined depending on the asset capacity, since a 50MVA transformer pays a higher amount of ENS and receives a higher remuneration than a 20MVA transformer. By crossing these inputs, the algorithm chooses those moments when applying a maintenance is feasible in order to improve the health condition transformer, and reducing costs. The output of this model is observed from 0 to 1. An output lower than 0.5 represents that Decision of applying maintenance is not recommended. Instead, an output higher than 0.5 represents that Decision of applying maintenance is recommended. In order to compare results from the proposing model with results of Section 3.2, interruptions expected will be calculated.

4.3.1. Results of proposed model for T1

Figure 4.6a and Fig. 4.6b present Risk and Decision, respectively, evaluated for T1 according to the proposed model. In Fig. 4.6a it is possible to observe that there is medium risk of 0.52 in several years, since the start of the simulation. This is the result of increasing gradient in HI, according to Fig. 2.2, that provides an increase in POF in some years. Risk becomes higher around year 12 to year 25 when HI is over 0.55, which represent a precaution POF of 0.42. These values of risk are evaluated along with the costs as presented in Chapter 4 for obtaining decision.



(a) Risk for T1

(b) Decision for T1

Figure 4.6.: Risk and Decision for T1

Besides, in Fig. 4.6b it is possible to observe that decision is positive for values higher than 0.5 in several years until year 15. In this case, since there is medium risk in the first years of operation and costs are higher, it is recommended to apply maintenance in these years. Despite the fact that the decision of applying maintenance is consecutive in some years, it was necessary to apply maintenance with a time difference of at least 3 years to observe the effect of maintenance. Although, Risk after year 15 is higher, the algorithm chooses not to apply maintenance after this year, since benefit of applying maintenance are no longer representative. That is to say that, if the asset fails inevitably after year 15, remuneration received, costs and benefit in ENS do not compensate the decision of applying maintenance.

Taking into account the decision from Fig. 4.6b, maintenance was applied in the chosen moments by the algorithm. In the same way that TBM, CBM and RCM, by applying a maintenance, only 5 health indices will be affected: DGA, %Sat, DS, IFT and H2O. In addition, after every maintenance applied, a new curve of HI is obtained. The resulting curve of HI and $\lambda(HI)$ for the proposed model applied to T1 are presented in Fig. 4.7. In this figure, it can be observed that with all the maintenances applied, it is possible to maintain the transformer health condition under 0.5 for most of the simulation time.

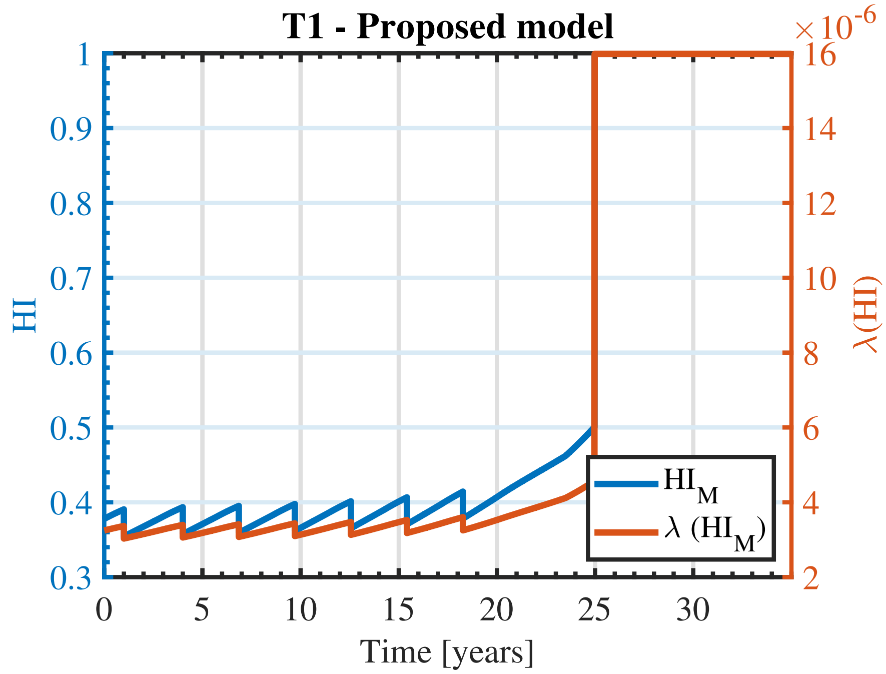


Figure 4.7.: HI and $\lambda(HI)$ for the proposed model for T1

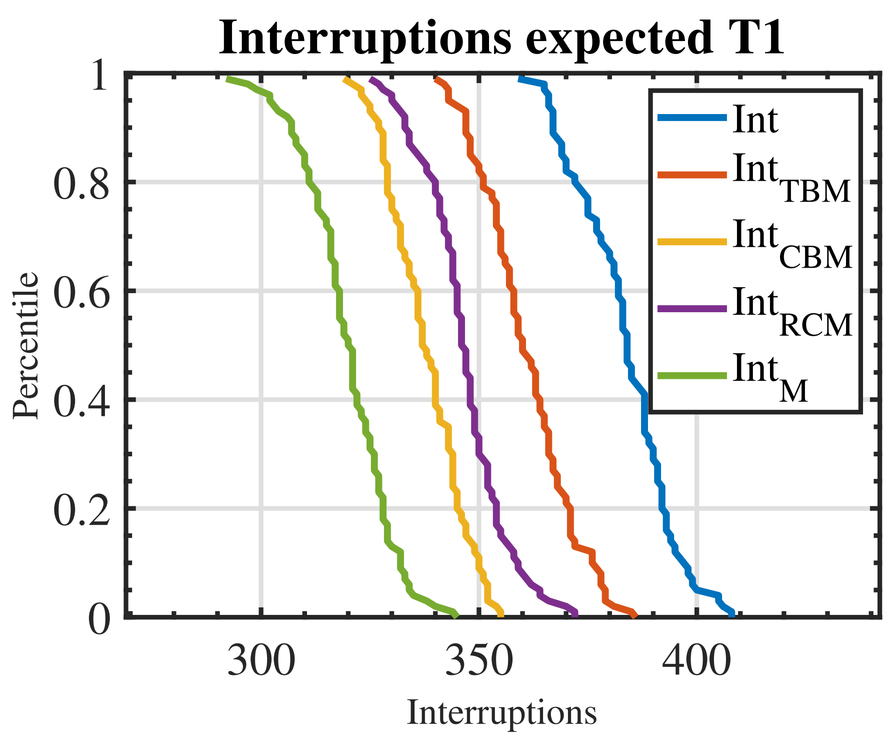
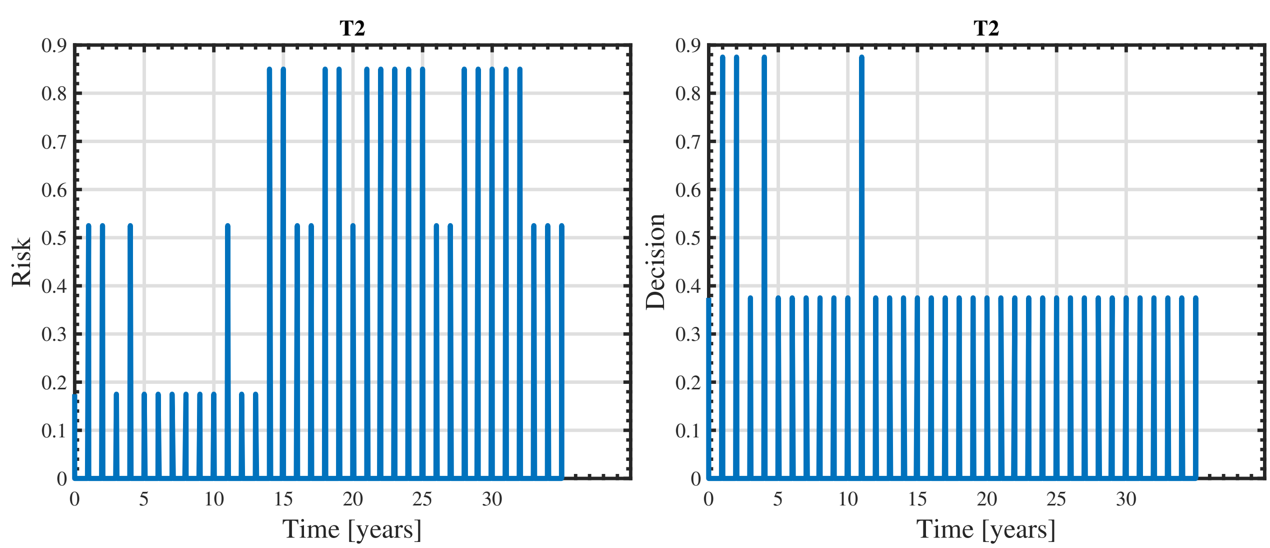


Figure 4.8.: Comparison of expected interruptions by proposed model for T1

Figure 4.8 shows the comparison of expected interruptions of proposed model applied to T1 and the other maintenance schemes applied in Section 3.2. The reduction in expected interruptions between Int and Int_M is **64**, which is higher than the result obtained by CBM, according to Table 4.4.

4.3.2. Results of proposed model for T2

Figure 4.9a presents Risk output for T2 according to the proposed model. For this case, risk has a value of 0.52 representing medium risk in the first years of simulation. Between year 5 and 10, risk is low since HI gradient remains constant in time. After after 15 years of simulation, risk tends to be between medium and high level, since the HI is over 0.6, as presented in Fig. 2.4, representing a POF around 0.45. Nevertheless, decision of applying maintenance is only positive in the first years of simulation, for a total of 4 maintenances, as shown in Fig. 4.9b. In this case, by applying maintenances in the first years of simulation, represents a considerable improvement of the transformer health index. In fact, by applying these maintenances, HI remains under 0.4 until year 15. After this year, HI gradient increases quickly. For this reason, risk is higher after year 15. However, applying maintenance after this do not compensate remuneration received after this year, nor the benefit of reduction in ENS. Applying extra maintenances after year 15 may depend on the operator criteria.



(a) Risk for T2 (b) Decision for T2

Figure 4.9.: Risk and Decision for T2

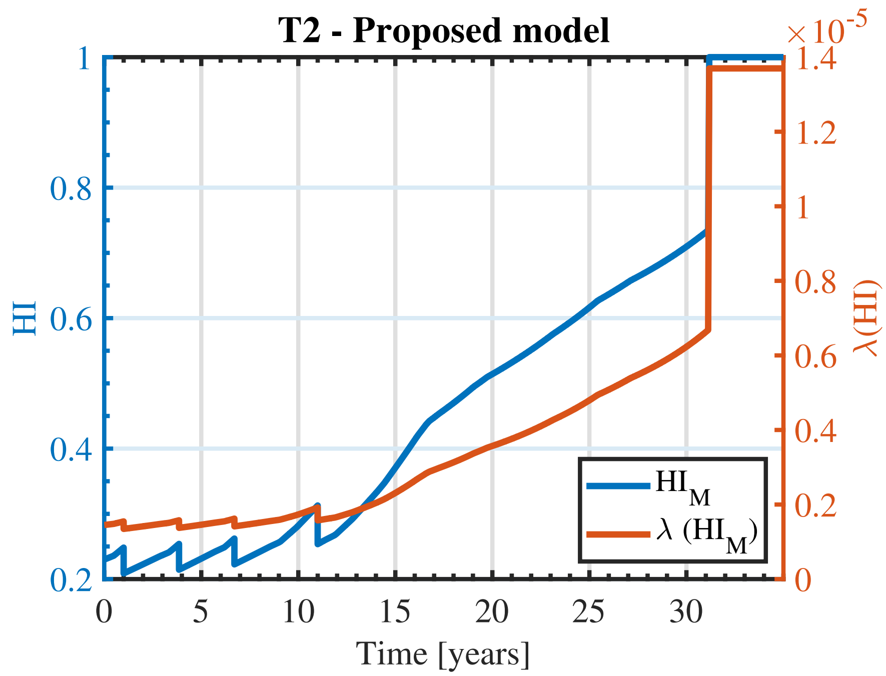


Figure 4.10.: HI and $\lambda(HI)$ for the proposed model for T2

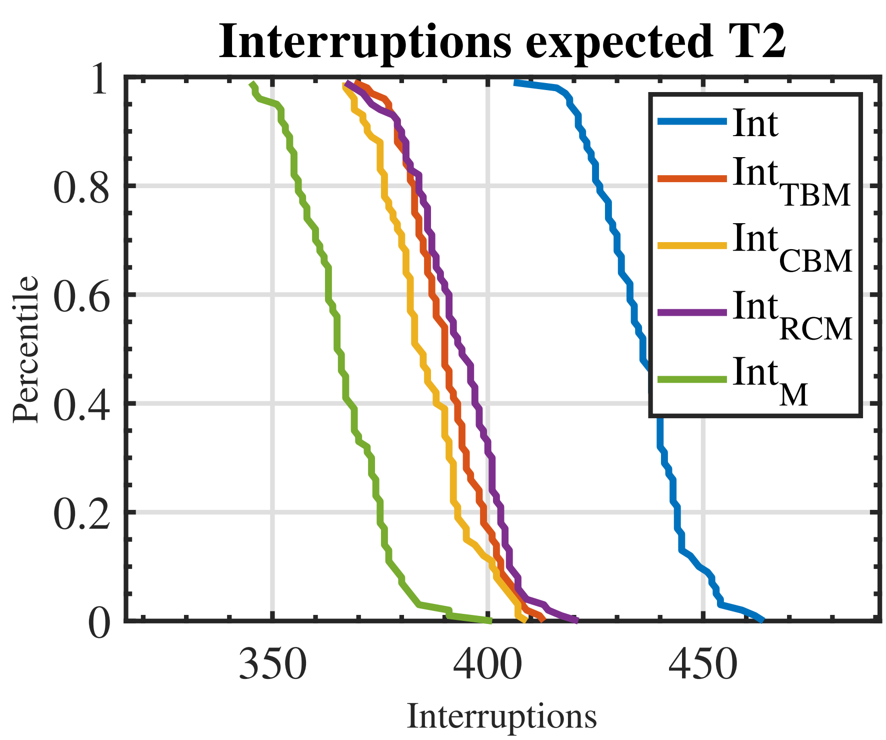
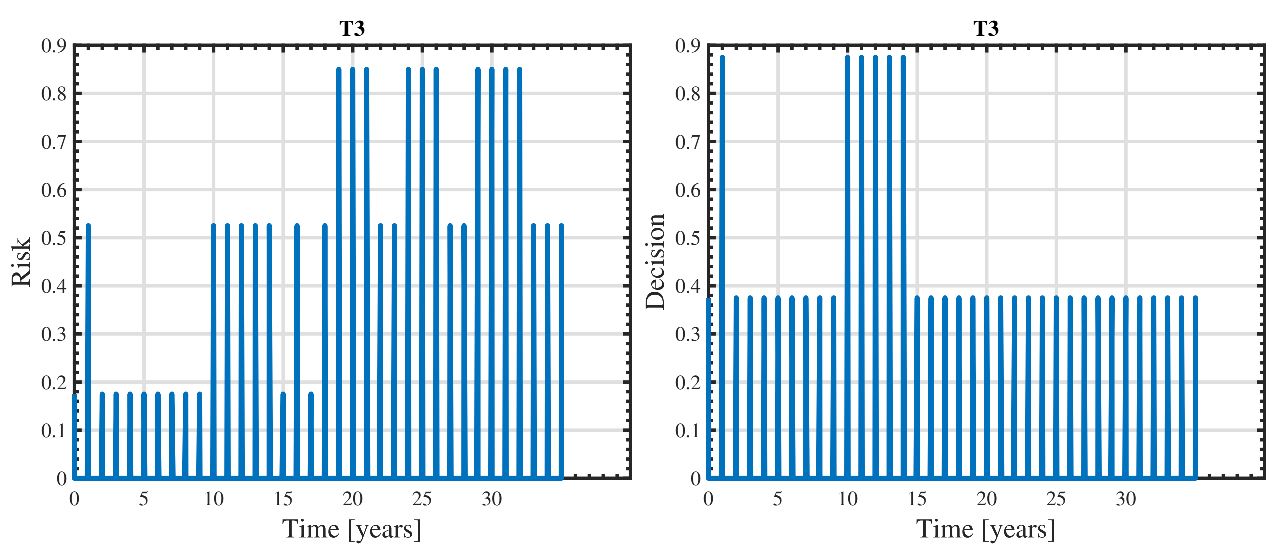


Figure 4.11.: Comparison of expected interruptions by proposed model for T2

Figure 4.10 presents the corresponding HI and $\lambda(HI)$ curves for the proposed model applied to T2. In addition, in Fig. 4.11, it is presented the comparison of expected interruptions with the proposed model for T2 along with the expected interruptions for the other maintenance schemes evaluated. For this case, the reduction in expected interruptions between Int and Int_M is **71** according to Table 4.4. This represents a better scenario for T2 than CBM. A higher reduction may be obtained with 1 or 2 maintenances applied after year 15.

4.3.3. Results of proposed model for T3

With respect to T3, in Fig. 4.12a and Fig. 4.12b are presented Risk and Decision obtained by the proposed model, respectively. In Fig. 4.12a it is possible to observe a low value of risk until year 10, with exception of year 1. Medium risk at year 1 may be as result of the high gradient of HI in the first year of simulation as seen in Fig. 2.6. Risk has a value of 0.52 from year 10 to year 18, representing a medium level risk. After this year, transformer risk is considered high. Nevertheless, in Fig. 4.12b it is possible to observe that decision of applying maintenance is positive in year 1. Between year 2 and 10, the decision is not to apply maintenance, since the risk is considered low. Later, in years from 10 to 15. Although, Risk is higher after year 15, applying maintenance may be highly expensive, yet not significant in improvements for the operator.



(a) Risk for T3 (b) Decision for T3

Figure 4.12.: Risk and Decision for T3

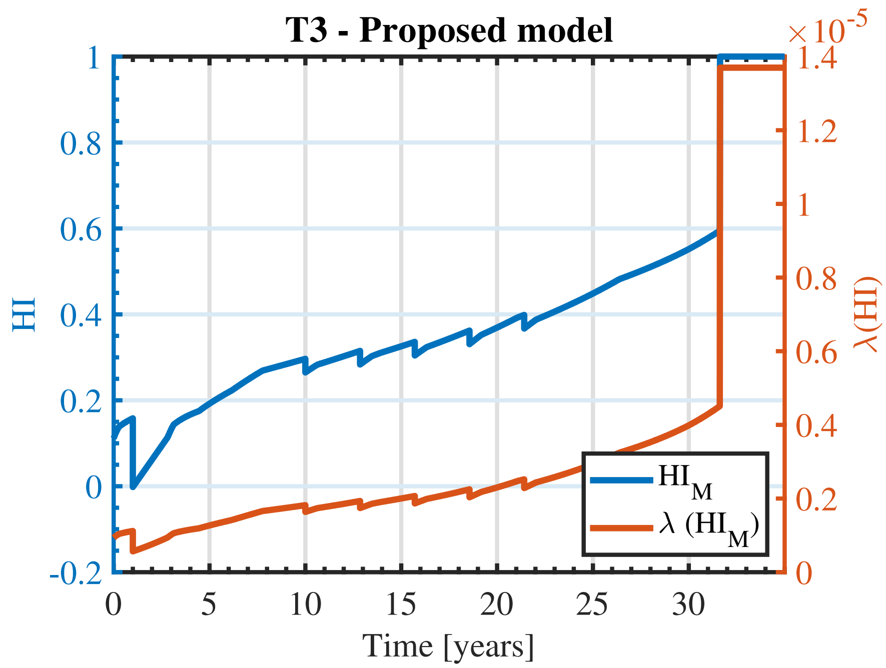


Figure 4.13.: HI and $\lambda(HI)$ for the proposed model for T3

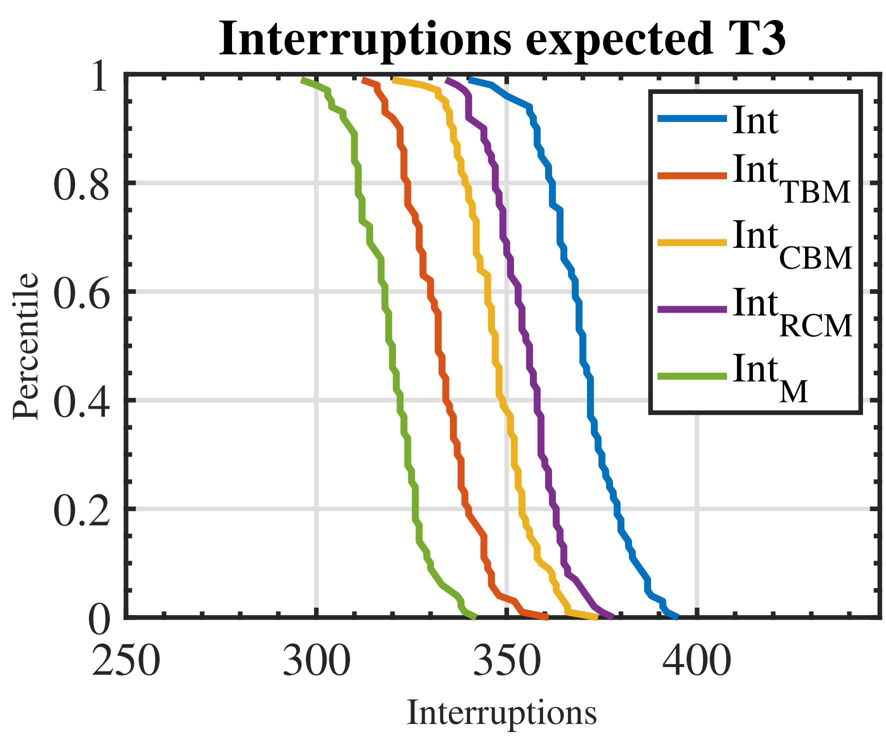
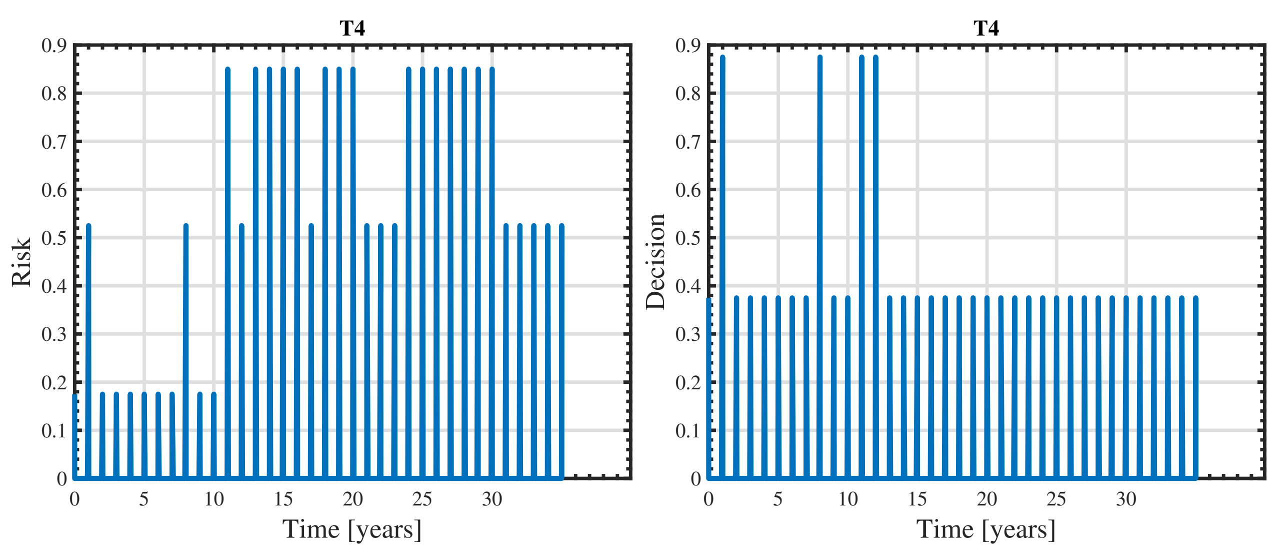


Figure 4.14.: Comparison of expected interruptions by proposed model for T3

Figure 4.13 presents the resulting curve of HI and $\lambda(HI)$ of T3 after applying the proposed model. In this curve, it is possible to observe that applying a maintenance in the firs year of simulation has a noticeable impact in the improvement of the transformer health condition. This maintenance is due to the high gradient of original HI in the first years of simulation. With respect to the expected interruptions for the proposed model applied to T3, in Fig. 4.14 is presented the comparison of these expected interruptions with the results of the other maintenance schemes. The reduction of expected interruptions of proposed model is **50**, as seen in Table 4.4.

4.3.4. Results of proposed model for T4

In this case, results are different. Figure 4.15a presents risk obtained for T4. For this transformer, risk is low in the first 10 years of operation, with exception of years 1 and 8, where risk reaches a value of 0.52. After year 10, risk tends to be between medium and high level, since POF for this transformer is higher than 0.4 according to Fig. 2.8. This can be an indicator that the health condition of the asset is getting accelerated. Between years 25 and 30, risk is high level since POF has a value over 0.5. Despite this, decision obtained for this transformer is different. In Fig. 4.15b can be observed that decision of applying maintenance is positive in 4 years. All maintenances are suggested before year 12 of simulation. After year 12, the algorithm does not choose more moments, since remuneration perceived does not compensate ENS and maintenance costs.



(a) Risk for T4 (b) Decision for T4

Figure 4.15.: Risk and Decision for T4

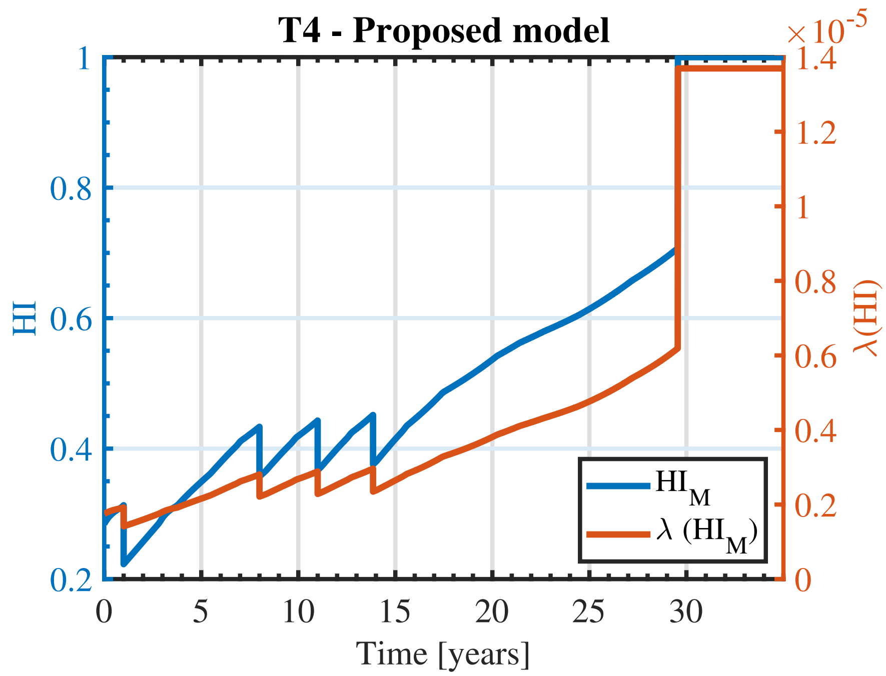


Figure 4.16.: HI and $\lambda(HI)$ for the proposed model for T4

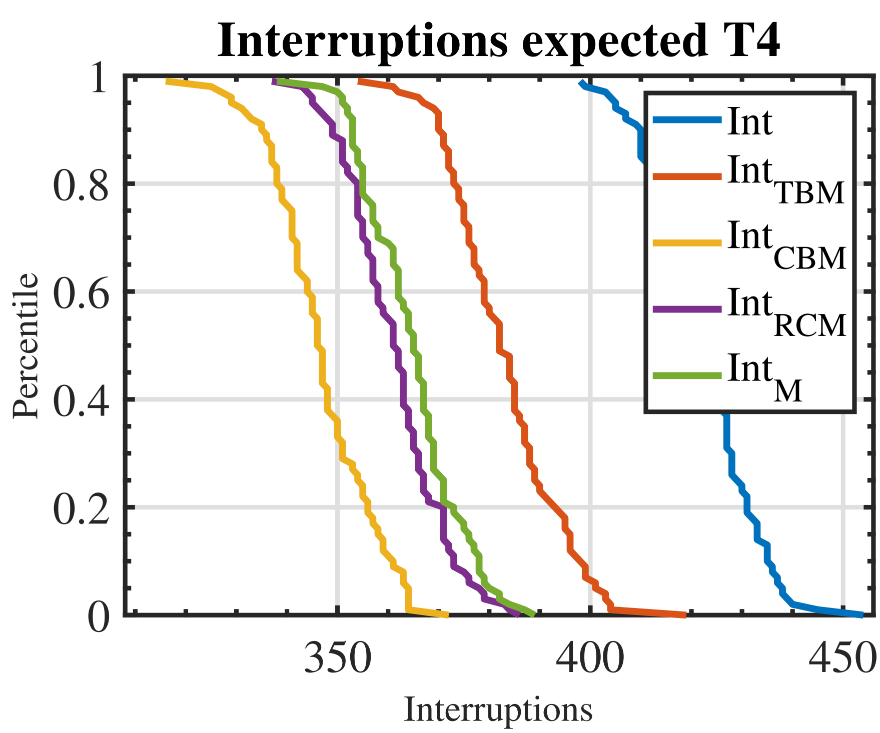


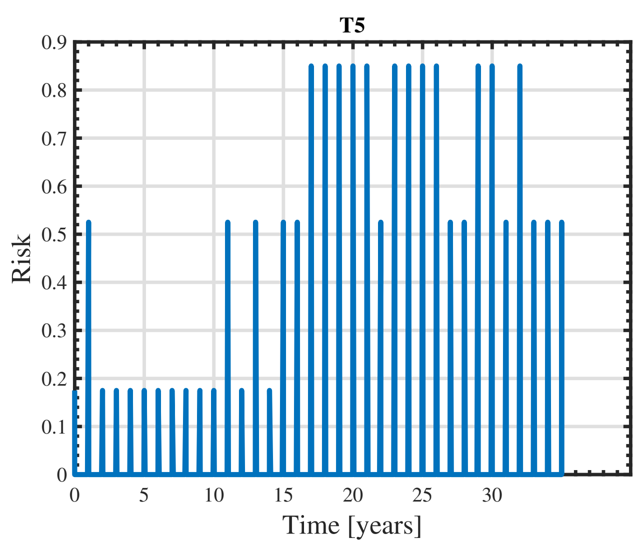
Figure 4.17.: Comparison of expected interruptions by proposed model for T4

The resulting curves of HI and $\lambda(HI)$ for T4 are presented in Fig. 4.16. In this figure, it can be appreciated that HI gradient of T4 is considerable, that is the reason why applying a maintenance in year 1 provides a noticeable improvement in the transformer health condition. In the consequent years, the gradient seems to indicate the accelerated deterioration of HI. Therefore, 3 maintenances more are applied in order to try to maintain HI constant. After applying these maintenances, the algorithm does not recommend applying more maintenances since the benefits may not compensate costs and incomes perceived.

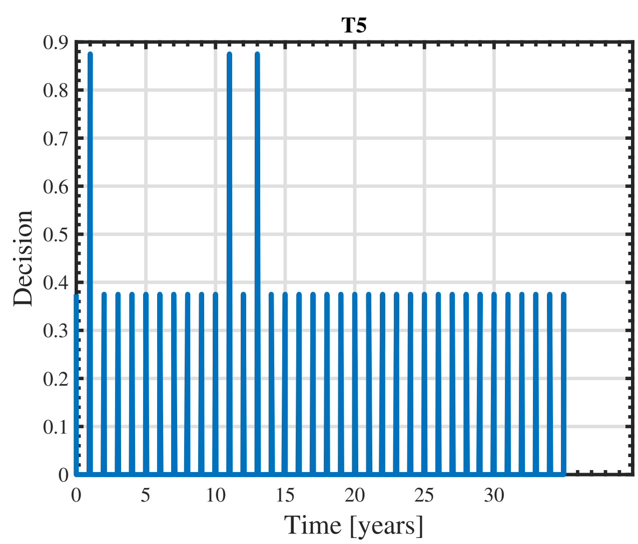
In Fig. 4.17 are presented the expected interruptions for T4. The reduction between expected interruptions of the proposed model for T4 is **57** according to Table 4.4. This value is higher than the reductions of TBM and RCM, but lower compared to the reduction of CBM. In this case, the best scenario for T4 is still CBM. However, it is important to mention that CBM nor the other schemes take into account the costs associated to the operation and remuneration of the asset. Therefore, by applying CBM to T4, there is a higher reduction of expected interruptions, but the cost might be higher than other schemes taking into account the amount of applied maintenances.

4.3.5. Results of proposed model for T5

Finally, the proposed model applied to T5 returns risk and decision according to Fig. 4.18a and Fig. 4.18b, respectively.



(a) Risk for T5



(b) Decision for T5

Figure 4.18.: Risk and Decision for T5

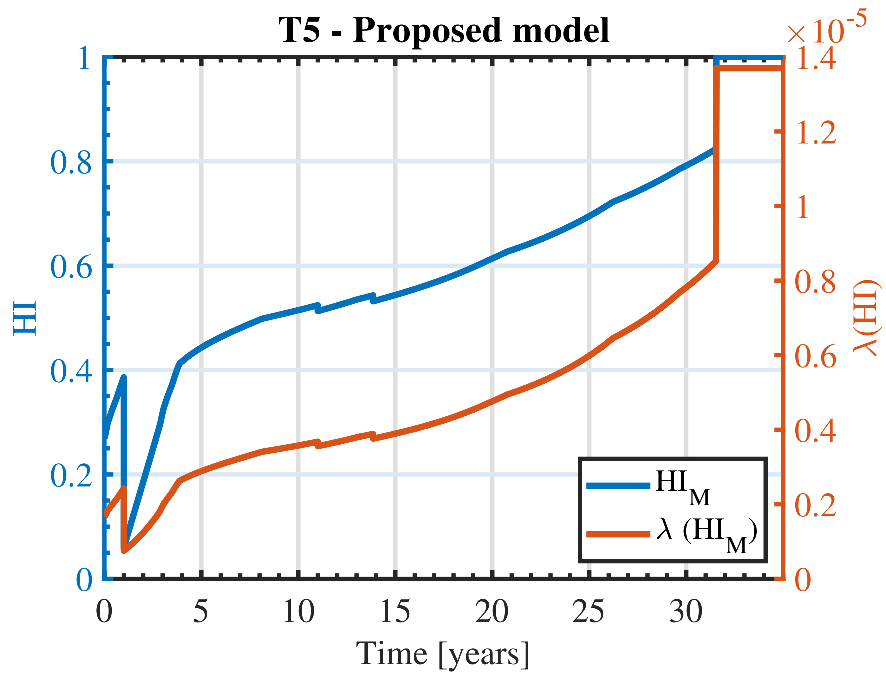


Figure 4.19.: HI and $\lambda(HI)$ for the proposed model for T5

In this case, in the first ten years of simulation, risk is considered low with exception of year 1, where risk has a value of 0.52. This medium level risk is a result of increase in HI gradient according to Fig. 2.10, which represents an increase in Cr for the operator. Between years 10 to 16, risk is between low and medium level, which can be the result of changes in Cr and the increase of POF. After 16 year, HI has reaches 0.6, representing a POF of 0.45. Therefore, risk tends to be considered high from year 16 to 30. Despite of this, Fig. 4.18b, shows that there are only 3 moments when decision is over 0.5, which means that applying maintenance is feasible in years 1, 11, and 13. Maintenance in year 1 is highly recommended in this case due to the accelerated gradient of HI in the first years of simulation.

The resulting curves of HI and $\lambda(HI)$ for the proposed model for T5 are presented in Fig. 4.19, where the effect of the first maintenance is appreciable. Although, due to the accelerated evolution of some indices of this transformer, seen in Fig. 2.9, this effect stays briefly. The effect of the other maintenances is also non appreciable.

Comparing the expected interruptions of the proposed model and the other schemes applied to T5 in Fig. 4.20, there is no considerable difference between Int$_{TBM}$, Int$_{CBM}$ and Int$_{RCM}$. The reduction of expected interruptions for the proposed model is **31**, according to Table 4.4. However, due to the accelerated evolution of the transformer health indices, the effect of applying different maintenance schemes is not appreciable.

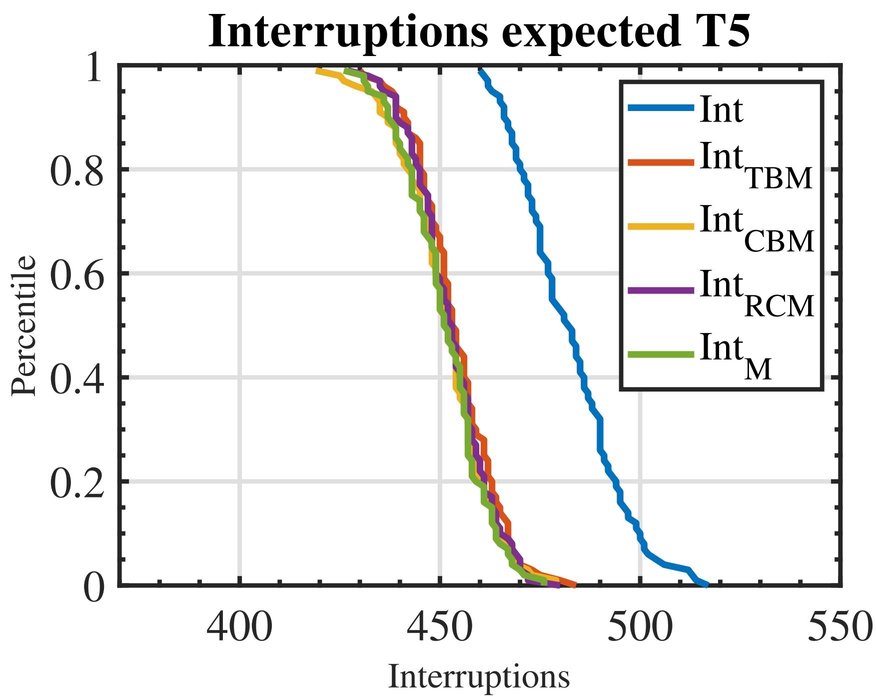


Figure 4.20.: Comparison of expected interruptions by proposed model for T2

Table 4.4 presents the results of the proposed model applied to the sample transformers, in comparison with the maintenance schemes applied in Chapter 3. From this table, it is possible to observe difference between P_{50} expected interruptions for all maintenances schemes applied. Being the proposed model the best scenario for T1, T2 and T3.

Table 4.4.: Results of ENS

Int with P_{50}	T1	T2	T3	T4	T5
Int	384	436	370	422	482
Int_{TBM}	363	391	333	382	455
Int_{CBM}	338	383	346	346	449
Int_{RCM}	345	393	356	363	453
Int_M	320	365	321	362	453

Conclusions

- From the evaluation of risk for the sample transformers, it is possible to conclude that risk tends to be between low and medium level along the first 15 years of simulation, since all transformers begin the simulation with HI different from zero and the cricitality estimated for each transformer. After year 15, for all transformers, risk tends to be between medium and high level.

- Considering the incomes received by the operator according to the new regulation, it is possible to corroborate that the maximum benefit can only be obtained as long as the asset is remunerated and the costs are not higher than the incomes. Therefore, applying more maintenances may only provide a benefit in reliability.
- It is possible to conclude that, taking into account the evaluation of costs associated to the transformers, in most of the cases, the algorithm chooses to apply maintenance in the first 15 to 20 years of operation. This can be considered as a preventive maintenance, since the algorithm chooses to apply maintenance when the costs are higher than the incomes, and the risk is considered in medium level.
- By applying maintenance in the first 15 years of operation, it was observed that HI remained under a good range of evolution. Therefore, it is possible to conclude that applying consecutive maintenances for maintaining HI under a good condition provides a high impact in the improvement of the transformer management.
- From the behaviour of all transformers implementing the proposed model, it is possible to corroborate that after year 15, although the risk tends to be in high level, the remaining incomes by remuneration do not compensate ENS cost. Therefore, applying more maintenances is not worthy from the economical point of view.
- From the case of transformer T5, it is possible to confirm that despite the maintenance scheme applied, impact of maintenance is not observable since the evolution of its health indices is too quick.
- In most of the cases, it was possible to observe a trend of applying maintenance in year 1 or 2. This was mainly due to the high gradient that presented almost all transformers in the first years of operation. This can be also considered as a preventive maintenance.
- With respect to T4, it is possible to conclude that improving the health condition to the maximum can have a high cost, since the proposed model estimates only 4 maintenances in order to provide the maximum benefit for the operator. Applying more maintenances is entirely optional.
- From the simulations of the proposed model, it can be concluded that the moment of applying the maintenance is crucial in order determine the impact of the maintenance. Defining the moment of applying maintenance depends entirely on the transformer health condition and the objectives pursued.

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5. Conclusions and suggestions

5.1. Conclusions

This research intended to present a health condition model with 9 health indices for evaluating HI. Taking into account the health condition simulation for all sample transformers, it can be confirmed that indices that remained constant in time do not represent a considerable contribution to the condition monitoring. This was observable in AN, L_{life} and Load indices because of the low load current that was considered for all transformers, with the exception of T5. For other indices, it was observed similar patterns of evolution in different moments of simulation; specially, with those indices related to the oil condition such as DS, IFT, $\%Sat$ and $H2O$.

With the HI simulation of the sample transformers, it was confirmed that a power transformer can reach the end of its life despite the fact that its health condition is different from 1. This was the case of all sample transformers. It was also corroborated that these sample transformers arrive at the end of their life before the 35 years of simulation because of its initial furans content.

From the application of TBM and RCM in all sample transformers, a pattern was observed with respect to the application of maintenances after year 20. In all cases, maintenances applied after year 20 tend to present a non significant impact in the reduction of interruptions. Therefore, it is possible to conclude that maintenances applied after year 20 tend to be worthless, because of the advanced health indices evolution after this year.

By applying TBM scheme, it was found that this scheme do not provide good results in reduction of expected interruptions for the transformers that presented an advanced HI. However, this scheme can present good results with young transformers, which was the case of T3. On the contrary, it was found that CBM is the maintenance that presents better results for most of the sample transformers. Yet, it is possible to conclude that this scheme can present disadvantages with respect to TBM when the asset is new.

Regarding the analysis of percentiles of expected interruptions, it was possible to observe that the for all transformers, with exception of T5, the worst scenarios of expected interruptions after applying maintenance were similar or better than the best scenario without maintenance. For T5, the worst scenario in expected interruptions after applying any maintenance was only comparable to the median of the case without maintenance. From these observations, it is possible to confirm that applying maintenance provides reduction in expected interruptions; then it is always recommended to apply maintenance. Criteria for applying maintenance depends on the objectives of the operator and provides different but good results depending of the transformer.

From the risk evaluation of the sample transformers in the proposed model, it was possible to observe that risk tends to be between low and medium level in the first 15 years of simulation because the fact that all transformers start the simulation with HI different from zero and the cricitality estimated for the transformer. After this year, risk tends to be between medium and high level for all transformers. In addition, according to the incomes received by the operator with the new regulation, it is possible to corroborate that the maximum benefit can only be obtained along the remuneration time.

It is possible to conclude that, evaluating the costs associated to the transformers, in most of the transformers, the algorithm chooses applying maintenance in the first 15 to 20 years of operation. In most of the cases, it was also observed a trend of applying maintenance in year 1 or 2. This can be considered as a preventive maintenance, taking into account that with consecutive maintenances in the first years of operation, it is possible to prevent an accelerated evolution of HI. Hence, through the application of several maintenances in the first years of operation it is possible to maintain a good health condition in the power transformer giving as result improvements in its management.

According to the results of all transformers implementing the proposed model, it was observed that after year 15, although the risk tends to be in high level, the costs by ENS and maintenances do not compensate the remuneration received by the transformer, therefore, applying more maintenances is not recommended from the economical point of view.

From the results obtained from the proposed model, it can be concluded that analyzing more variables and criteria helps to establish a more precise maintenance scheme according to the operator requirements, since the moment of applying the maintenance is crucial to determine its impact. Proposing a different model of variables associated with the transformer to determine these moments was the purpose of this research.

5.2. Suggestions

- Part of this research is related to the approach proposed for evaluating decision making through fuzzy logic in power transformers was presented in [1].

- Papers [2] and [3] are related to this topic, presenting an evaluation of risk in medium term. However, a different approach is presented in these papers, since they consider an asset management system for short, medium and long term. The results presented here are related of the asset management system developed for Enel-Codensa.
- As new regulation CREG 015 of 2018 changed the panorama of remuneration in Colombia, it is expected that all operators in Colombia have proposed and applied their own asset management system, by the end of 2023. Therefore, there will be a increase in the methodologies, models, papers proposed about this topic.

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A. Appendix A:

A.1. Historical tests data of sample transformers owned by ENEL-Codensa.

This sections presents the historical data tests of DGA, furans and physical-chemical tests of the sample transformers.

Table A.1.: Physical-chemical historic tests for T1.

Test date	H2O [mg/kg]	Sat [%]	IFT [mN/m]	DS [kV]	AN [mg KOH/g]
23/01/2007	8,10	7,00	29,55	34,46	0,01
21/05/2008	8,30	7,00	31,50	33,22	0,01
26/08/2008	7,90	7,00	30,15	41,58	0,01
30/04/2009	11,90	8,00	29,81	36,00	0,02
27/04/2010	14,30	10,00	26,70	35,04	0,02
14/12/2011	9,30	8,00	27,79	39,64	0,01
30/05/2013	9,50	6,00	29,21	39,88	0,02
21/04/2014	9,50	8,00	27,33	44,40	0,02
11/06/2015	9,10	8,00	27,86	35,64	0,04
6/07/2016	10,80	8,00	26,12	29,50	0,02
11/05/2017	10,10	8,00	29,22	20,62	0,02

Table A.2.: Physical-chemical historic tests for T2.

Test date	H2O [mg/kg]	Sat [%]	IFT [mN/m]	DS [kV]	AN [mg KOH/g]
3/01/2007	16,20	0,00	32,70	27,06	0,01
12/01/2007	11,30	10,00	35,44	30,46	0,01
26/08/2008	12,50	10,00	40,41	50,44	0,01
30/04/2009	14,00	8,00	39,08	56,50	0,01
27/04/2010	13,60	8,00	37,80	31,28	0,01
15/12/2011	13,90	11,00	36,22	52,44	0,01
31/05/2012	15,20	8,00	33,87	43,32	0,01
11/06/2015	17,30	14,00	32,96	31,04	0,03
12/05/2017	17,30	12,00	31,61	30,34	0,02
6/07/2016	10,80	8,00	26,12	29,50	0,02
11/05/2017	10,10	8,00	29,22	20,62	0,02

Table A.3.: Physical-chemical historic tests for T3.

Test date	H2O [mg/kg]	Sat [%]	IFT [mN/m]	DS [kV]	AN [mg KOH/g]
24/02/2009	3,40	3,00	39,64	39,20	0,01
18/11/2010	5,80	3,00	40,64	54,74	0,01
15/12/2011	47,90	28,00	41,45	15,14	0,01
9/04/2013	4,30	3,00	40,74	45,10	0,00
12/04/2013	3,60	4,00	39,48	47,10	0,01
6/02/2014	5,20	3,00	41,00	46,38	0,01
16/02/2017	3,80	4,00	38,41	47,52	0,01

Table A.4.: Physical-chemical historic tests for T4.

Test date	H2O [mg/kg]	Sat [%]	IFT [mN/m]	DS [kV]	AN [mg KOH/g]
18/06/2010	3,90	2,00	37,48	50,22	0,01
28/02/2012	3,90	3,00	37,88	50,80	0,01
6/05/2013	4,90	3,00	37,74	48,26	0,01
19/03/2014	5,30	3,00	37,43	47,98	0,01
25/02/2015	5,10	3,00	37,39	45,12	0,01
24/04/2017	5,60	3,00	36,49	33,22	0,02

Table A.5.: Physical-chemical historic tests for T5.

Phase	Test date	H2O [mg/kg]	Sat [%]	IFT [mN/m]	DS [kV]	AN [mg KOH/g]
A	18/06/2008	2,70	0,00	42,47	44,74	0,01
	18/03/2019	30,60	35,27	36,12	16,38	0,01
B	18/06/2008	3,20	3,00	43,09	48,38	0,00
	18/03/2019	35,40	44,16	32,71	14,94	0,01
C	18/06/2008	3,30	3,00	42,18	50,00	0,00
	18/03/2019	29,90	25,37	34,98	19,08	0,01

Table A.6.: Furans historic tests for T1.

Test date	$5-HMF$ [ppb]	$2-FOL$ [ppb]	$2-FAL$ [ppb]	$2-ACF$ [ppb]	$5-MEF$ [ppb]
17/02/2012	4	609	167	0	0
6/09/2013	0	0	544	0	0
26/05/2014	0	0	428	0	0
18/06/2015	0	0	590	0	0
17/07/2017	0	0	112	0	0
11/01/2019	0	260	204	35	0

Table A.7.: Furans historic tests for T2.

Test date	$5-HMF$ [ppb]	$2-FOL$ [ppb]	$2-FAL$ [ppb]	$2-ACF$ [ppb]	$5-MEF$ [ppb]
17/02/2012	2	377	12	3	0
17/06/2015	0	0	46	0	0
17/07/2017	0	0	64	0	0

Table A.8.: Furans historic tests for T3.

Test date	$5-HMF$ [ppb]	$2-FOL$ [ppb]	$2-FAL$ [ppb]	$2-ACF$ [ppb]	$5-MEF$ [ppb]
17/02/2012	0	0	1	38	0
18/04/2013	0	0	0	43	0
10/02/2014	0	0	0	0	0
28/02/2017	0	0	6	68	0

Table A.9.: Furans historic tests for T4.

Test date	$5-HMF$ [ppb]	$2-FOL$ [ppb]	$2-FAL$ [ppb]	$2-ACF$ [ppb]	$5-MEF$ [ppb]
20/07/2012	0	0	5	0	0
5/09/2013	0	0	245	0	0
26/05/2014	0	0	0	0	0
22/04/2015	0	0	201	0	6
10/07/2017	0	0	60	0	0

Table A.10.: Furans historic tests for T5.

Phase	Test date	$5-HMF$ [ppb]	$2-FOL$ [ppb]	$2-FAL$ [ppb]	$2-ACF$ [ppb]	$5-MEF$ [ppb]
A	19/10/2011	0	0	6	0	0
	2/08/2012	0	0	2	0	0
	6/09/2013	0	0	0	0	0
	16/06/2014	0	0	0	0	0
	22/04/2015	0	0	16	0	8
	11/12/2015	0	0	0	0	0
	21/06/2018	0	0	0	0	0
B	19/10/2011	0	0	6	0	0
	2/08/2012	0	0	0	0	0
	6/09/2013	0	0	0	0	0
	26/05/2014	0	0	3	0	0
	16/06/2014	0	0	0	0	0
	22/04/2015	0	0	16	0	0
	11/12/2015	0	0	0	0	0
	13/07/2017	0	0	0	0	0
	21/06/2018	0	0	0	0	0
C	19/10/2011	0	0	4	0	0
	2/08/2012	0	0	0	0	0
	6/09/2013	0	0	16	0	0
	16/06/2014	0	0	0	0	0
	22/04/2015	0	0	17	0	0
	11/12/2015	0	0	0	0	0
	21/06/2018	0	0	0	0	0

Table A.11.: DGA historic tests for T1.

Test date	H_2 [ppm]	O [ppm]	N [ppm]	CO [ppm]	CH_4 [ppm]	CO_2 [ppm]	C_2H_4 [ppm]	C_2H_6 [ppm]	C_2H_2 [ppm]
22/01/2007	31,18	18586,15	38981,54	82,29	6,86	1147,98	12,09	1,02	96,35
6/02/2007	28,49	16201,13	34120,00	70,36	6,22	1082,57	11,73	0,71	96,37
9/04/2007	30,43	17113,73	39527,61	72,55	7,61	1281,56	14,25	1,35	145,66
24/04/2007	31,03	18535,05	39992,83	67,35	8,05	1269,50	15,83	1,55	146,64
16/05/2007	32,73	17171,66	40631,14	67,18	8,45	1300,70	16,32	1,57	158,78
22/06/2007	33,82	18569,83	43417,21	74,05	8,98	1405,56	17,80	1,79	162,29
6/07/2007	31,88	18487,59	42721,20	70,95	8,84	1408,12	18,58	1,90	167,17
11/09/2007	27,41	14225,96	32385,48	62,26	7,06	1219,61	15,86	1,58	152,98
13/12/2007	25,97	15067,54	36020,55	67,96	7,68	1098,59	18,32	1,76	156,95
24/04/2008	28,11	17380,62	43368,37	73,78	8,42	1310,44	18,37	2,42	184,15
22/05/2008	20,63	17682,55	40756,40	66,08	7,31	1269,51	19,57	1,96	175,04
16/06/2008	17,94	17011,15	38795,50	59,04	5,99	1210,55	15,54	1,57	147,98
20/08/2008	11,67	17935,81	44100,82	69,24	5,21	1323,45	14,83	1,46	149,56
9/12/2008	10,20	18085,36	42964,14	74,79	4,08	1477,29	17,05	1,87	156,85
20/03/2009	11,04	17529,16	43302,61	98,80	3,77	1563,81	14,16	1,57	144,13
26/04/2010	15,76	19155,04	47255,63	108,36	4,42	1704,20	13,83	1,61	78,35
8/11/2010	17,38	18592,70	43485,28	65,15	4,07	1577,71	12,61	1,53	83,22
1/12/2011	18,99	18690,34	42710,61	55,10	4,55	1282,84	12,43	1,69	78,09
16/05/2013	6,23	18020,19	43032,46	51,15	1,64	1103,31	5,83	0,21	29,86
31/03/2014	5,47	20060,42	43713,61	0,00	0,00	1017,07	5,95	1,02	28,19
3/06/2015	7,36	18935,04	42720,09	53,62	1,81	978,14	4,46	1,00	20,14
6/07/2016	8,37	18091,69	46939,96	55,68	0,00	1079,95	9,19	26,30	15,50
10/05/2017	12,69	11520,18	50781,00	89,33	2,37	1346,89	5,25	2,40	16,03
24/08/2018	4,40	5981,84	4516,49	13,74	0,00	1335,47	1,60	1,59	0,00

Table A.12.: DGA historic tests for T2.

Test date	H_2 [ppm]	O [ppm]	N [ppm]	CO [ppm]	CH_4 [ppm]	CO_2 [ppm]	C_2H_4 [ppm]	C_2H_6 [ppm]	C_2H_2 [ppm]
14/08/2008	30,94	7013,37	23268,57	108,72	1,58	740,95	0,91	0,36	0,65
9/12/2008	27,49	7360,25	31303,61	223,94	3,08	1495,38	2,65	0,85	0,38
20/03/2009	20,82	8880,83	36471,56	267,36	3,34	1703,22	3,19	0,65	0,31
26/04/2010	18,72	13160,20	56889,29	380,77	4,82	1915,63	11,02	1,14	0,00
5/11/2010	11,69	11250,75	45047,89	268,47	3,02	1765,94	10,40	0,86	0,00
2/12/2011	15,49	9673,16	50507,99	323,85	3,56	2221,44	18,48	1,02	0,00
22/05/2012	13,12	11217,99	57543,11	299,72	3,22	1693,70	19,11	0,95	0,00
2/06/2015	18,64	5633,33	47334,12	343,51	5,69	3045,53	45,98	2,41	0,00
10/05/2017	27,03	3419,20	47789,07	323,52	5,63	2765,10	44,68	1,94	0,00

Table A.13.: DGA historic tests for T3.

Test date	H_2 [ppm]	O [ppm]	N [ppm]	CO [ppm]	CH_4 [ppm]	CO_2 [ppm]	C_2H_4 [ppm]	C_2H_6 [ppm]	C_2H_2 [ppm]
11/04/2007	69,95	1291,06	6356,37	79,07	1,02	191,39	0,15	0,07	0,00
12/06/2007	83,64	714,84	6300,83	78,90	1,79	188,18	0,18	0,39	0,00
16/11/2007	83,66	714,56	6613,16	98,65	4,47	264,65	0,41	1,82	0,00
27/02/2009	70,99	1268,00	11152,07	123,18	9,94	387,68	0,77	5,16	0,00
8/11/2010	18,95	260,14	4800,17	42,77	7,01	187,13	0,27	4,88	0,00
2/12/2011	16,63	330,94	8344,82	56,73	13,05	301,22	0,46	12,47	0,00
8/03/2013	23,49	1087,23	20458,66	132,85	39,59	466,32	1,41	44,78	0,00
21/03/2013	22,92	2563,53	25749,94	103,54	32,83	438,26	1,19	41,67	0,00
6/02/2014	13,47	383,32	7432,81	49,19	16,50	272,59	0,64	19,04	0,00
4/01/2017	16,32	382,50	21686,22	119,01	58,03	882,55	2,61	90,93	0,00
1/11/2018	8,83	3402,17	21376,89	53,74	28,86	428,10	1,74	46,64	0,00

Table A.14.: DGA historic tests for T4.

Test date	H_2 [ppm]	O [ppm]	N [ppm]	CO [ppm]	CH_4 [ppm]	CO_2 [ppm]	C_2H_4 [ppm]	C_2H_6 [ppm]	C_2H_2 [ppm]
17/06/2010	17,65	788,93	42038,18	92,11	31,82	846,84	4,20	53,74	0,00
24/02/2012	16,28	1386,29	54565,27	88,04	33,99	781,05	3,98	54,51	0,94
11/04/2013	16,32	1284,67	53036,35	93,97	34,73	724,27	3,03	40,38	0,00
13/03/2014	10,93	1475,83	47936,09	77,92	41,00	981,16	5,09	57,82	0,00
11/02/2015	7,42	5879,23	51297,54	72,68	42,83	936,34	4,31	49,62	0,00
17/04/2017	14,74	289,38	50072,68	99,73	47,82	1188,82	4,95	68,70	0,00

Table A.15.: DGA historic tests for T5.

Phase	Test date	H_2 [ppm]	O [ppm]	N [ppm]	CO [ppm]	CH_4 [ppm]	CO_2 [ppm]	C_2H_4 [ppm]	C_2H_6 [ppm]	C_2H_2 [ppm]
A	13/12/2007	25,64	8163,84	26039,70	90,39	1,18	241,89	0,20	0,14	0,00
	12/05/2008	26,16	6294,32	21886,98	107,78	1,25	249,37	0,28	0,21	0,00
	16/06/2008	35,19	8829,77	32934,75	160,62	1,85	314,74	0,38	0,24	0,00
	14/08/2008	35,08	8506,08	33611,61	179,87	2,03	399,41	0,59	0,42	0,00
	4/12/2008	35,25	10057,74	43816,32	197,83	2,26	355,38	0,78	0,42	0,00
B	13/12/2007	33,02	6409,96	23918,14	95,82	1,48	196,38	0,27	0,32	0,00
	14/05/2008	61,94	5684,46	30604,82	149,38	16,32	257,90	22,78	3,20	0,88
	16/06/2008	62,69	5437,75	31412,56	175,68	18,09	304,20	26,20	3,73	1,01
	14/08/2008	64,93	4800,28	31870,76	193,10	17,83	375,62	25,85	3,99	0,89
	4/12/2008	65,84	4241,03	35936,21	209,93	18,02	323,11	25,51	4,00	0,74
C	13/12/2007	47,41	7984,65	32991,52	129,11	2,03	256,02	0,37	0,54	0,00
	14/05/2008	70,34	5368,27	35033,93	193,35	3,01	283,38	0,70	0,77	0,00
	16/06/2008	67,08	5496,21	40029,16	226,12	3,68	362,46	1,00	1,05	0,00
	14/08/2008	65,37	4149,56	34422,16	212,33	3,28	379,39	0,80	1,10	0,00
	4/12/2008	68,46	2402,19	40253,44	251,13	4,24	352,01	1,14	1,40	0,00

A.2. Historical load data of sample transformers owned by ENEL-Codensa.

This section presents the historical data of sample transformers load for approximately the last five years of operation, starting in 25/09/2013 at 00:00 until 30/09/2018 at 23:00. Figure A.1 presents the historical load data for T1, being the $P_{10} = 0.29$, $P_{50} = 0.39$,

$P_{90} = 0.54$. Although the 90^{th} percentile of the data exceeds 50% of loading, the transformer is still considered lowly loaded.

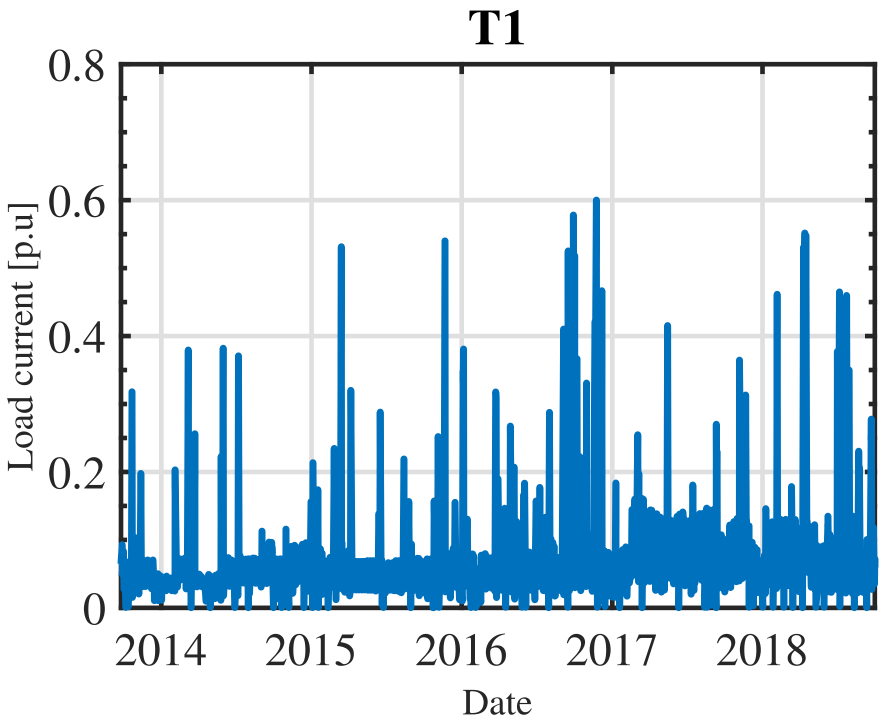


Figure A.1.: Historic load for T1.

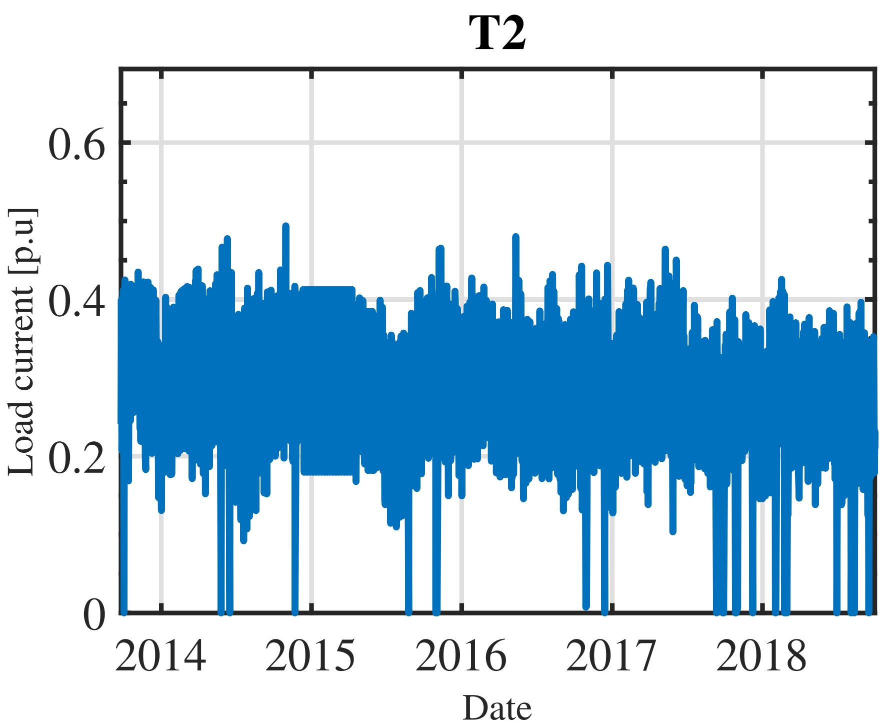


Figure A.2.: Historic load for T2.

Figure A.2 presents the historical load data for T2, being the $P_{10} = 0.29$, $P_{50} = 0.41$, $P_{90} = 0.48$ It is observed that 90% of samples are below the 0.48 of the transformer loading, so it is considered not highly loaded.

In Fig. A.3 it is presented the historical load data for T3, being the $P_{10} = 0.24$, $P_{50} = 0.41$, $P_{90} = 0.45$. This means that at least 90% of the samples are under the half of the rated capacity of the transformer and, as the previous transformers, it is considered lowly loaded.

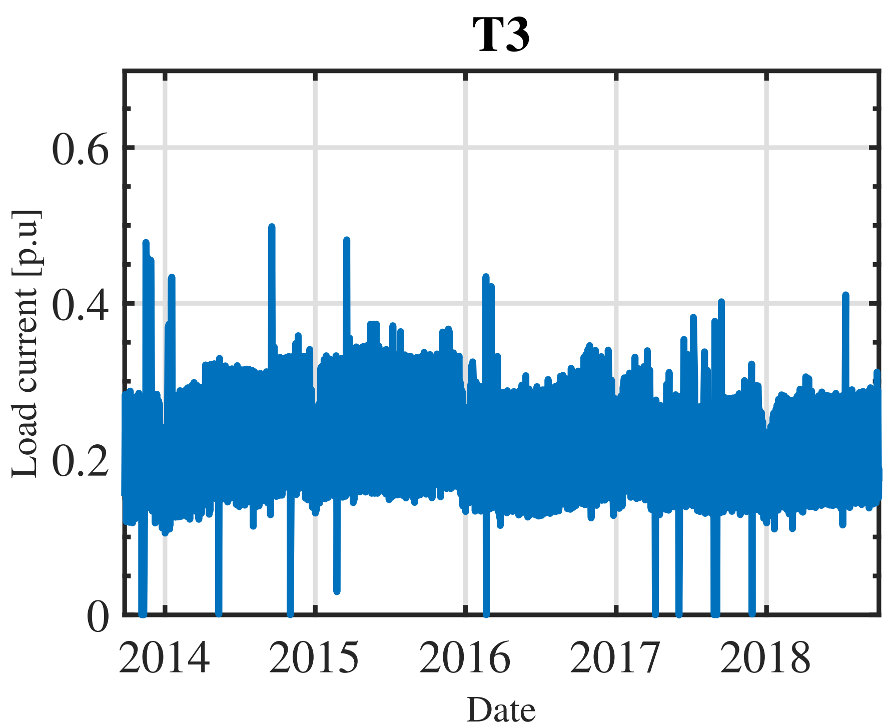


Figure A.3.: Historic load for T3.

Figure A.4 presents the historical load data for T4, being the $P_{10} = 0.43$, $P_{50} = 0.54$, $P_{90} = 0.61$. It is observed that the 10^{th} percentile is not far from the 90^{th} percentile, which indicates that the load is relatively constant although it does not reach a value to confirm that the transformer has been highly loaded.

Figure A.5 presents the historical load data for T5, being the $P_{10} = 0.84$, $P_{50} = 1.15$, $P_{90} = 1.26$. In contrast to the other transformers, the 10^{th} percentile of this transformer is at 0.84, which indicates that it is loaded. In addition, with the 50^{th} percentile it is verified that this asset nominal load is exceeded at least a half of use time.

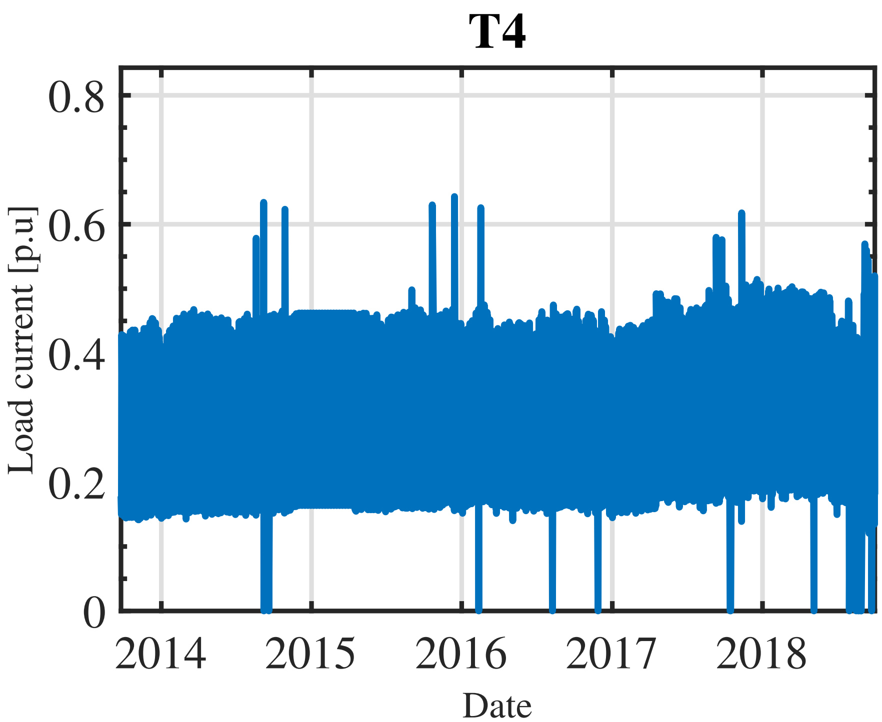


Figure A.4.: Historic load for T4.

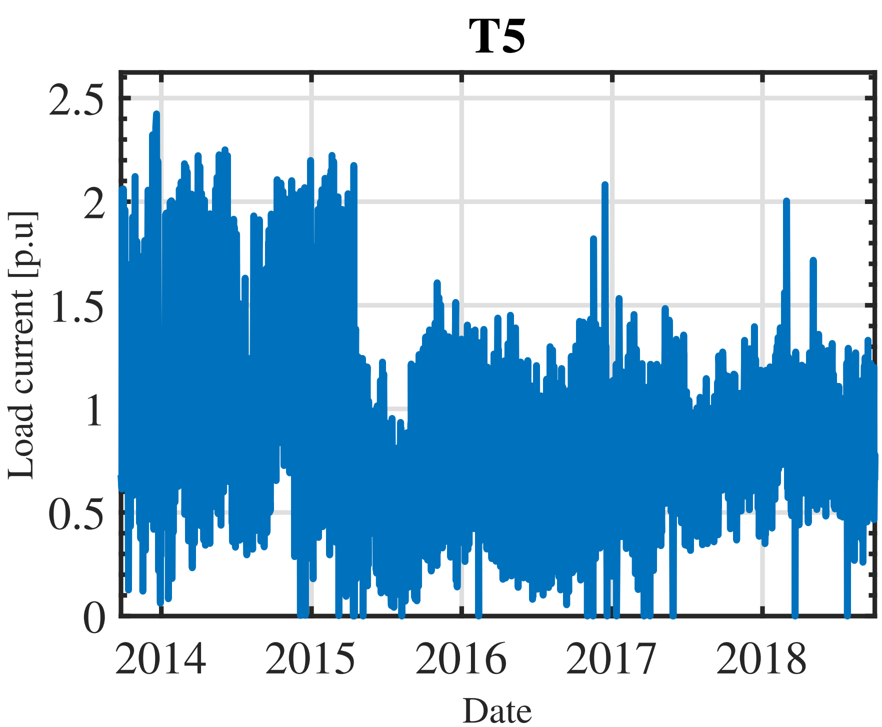


Figure A.5.: Historic load for T5.

A.2.1. Projection load from historical data of sample transformers owned by ENEL-Codensa.

For the simulations presented in Chapter 2, it was necessary implementing a load current for every sample transformer. In order to perform a projection of load, it was performed an correlation analysis, however, in most of the cases, the repetition interval was around 1 or 2 days, which means that the load profile repeats itself every 1 or 2 days, with slight differences between the days. Therefore, for the projection, a period of one week was chosen in order to project load current.

In addition, it is observed that for some transformers, loading along the five years of data tend to decrease, such as seen in Fig. A.2 and Fig. A.5. This can have different explanation, but it also complicates the process for projection the load transformer for the 35 years of simulation. Hence, it was chosen to maintain load constant for the 35 years of simulation. Since the loading in some transformers such as T1 and T3 is barely high, and for T2 and T4 is not even 0.5, it was necessary to select the week with maximum value of the five years. While for T5, which is the only one that has been highly loaded in the five years of historical data, from the maximum of week of every year, the lowest week was selected.

Weeks selected to project along 35 years starting in 01/10/2018 at 00:00 for every sample transformer are presented in Table A.16- Table A.20, and plotted in Fig. A.6-Fig. A.10.

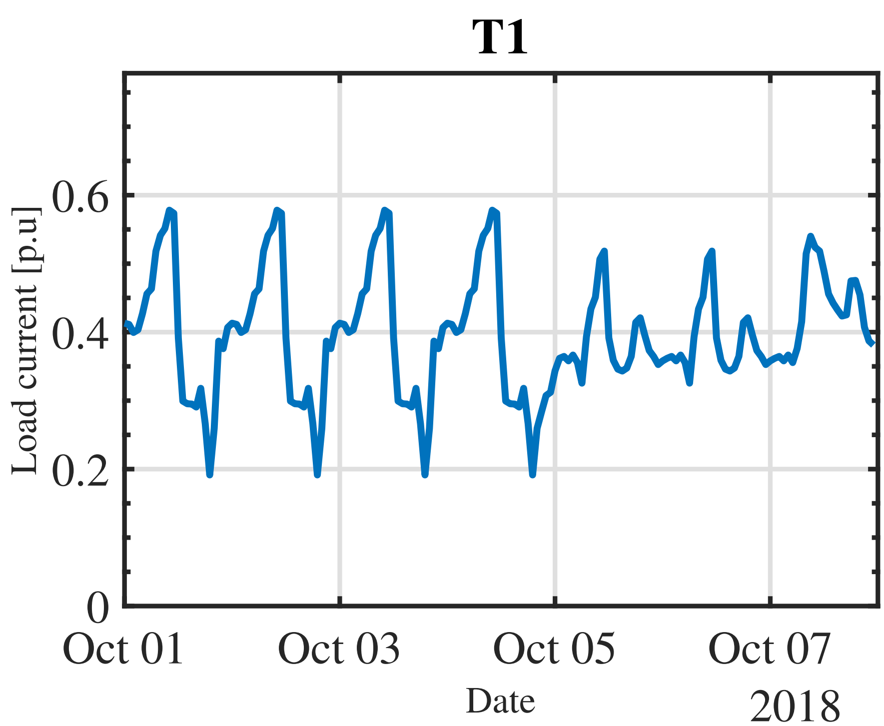


Figure A.6.: Selected week for load projection for T1 according to Table A.16

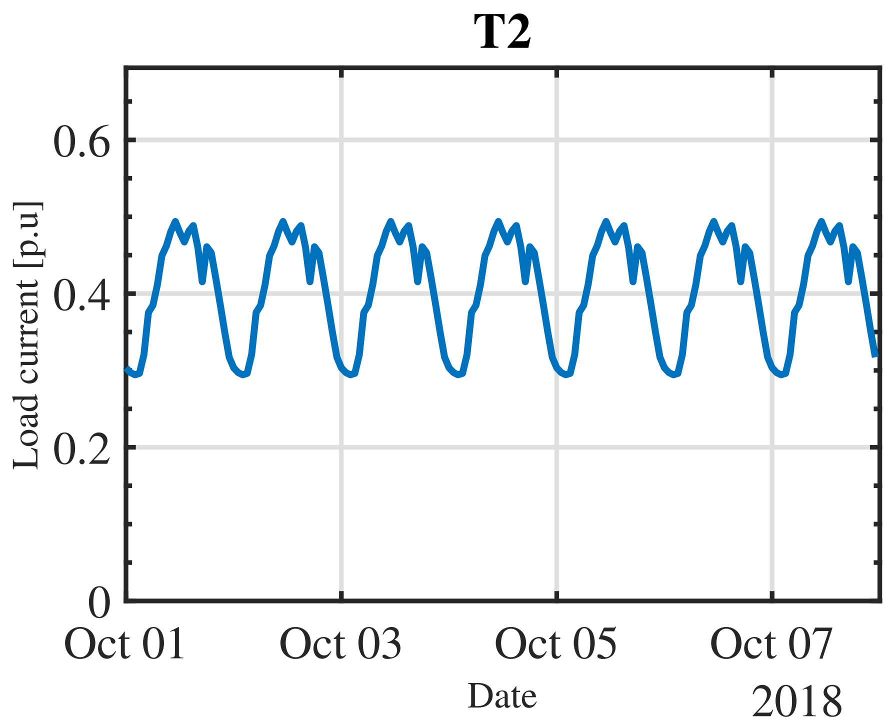


Figure A.7.: Selected week for load projection for T2 according to Table A.17

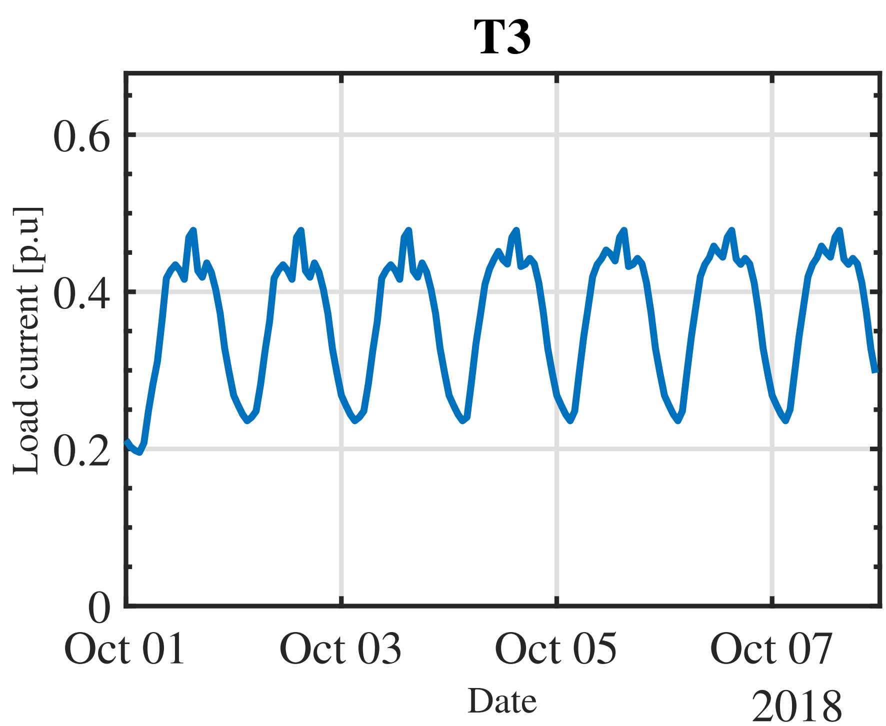


Figure A.8.: Selected week for load projection for T3 according to Table A.18

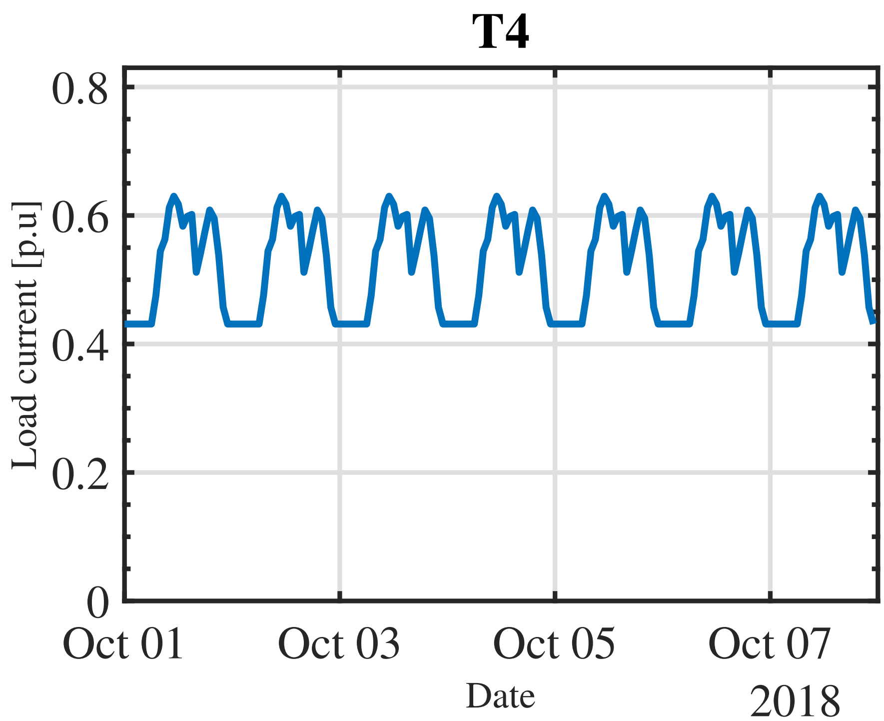


Figure A.9.: Selected week for load projection for T4 according to Table A.19

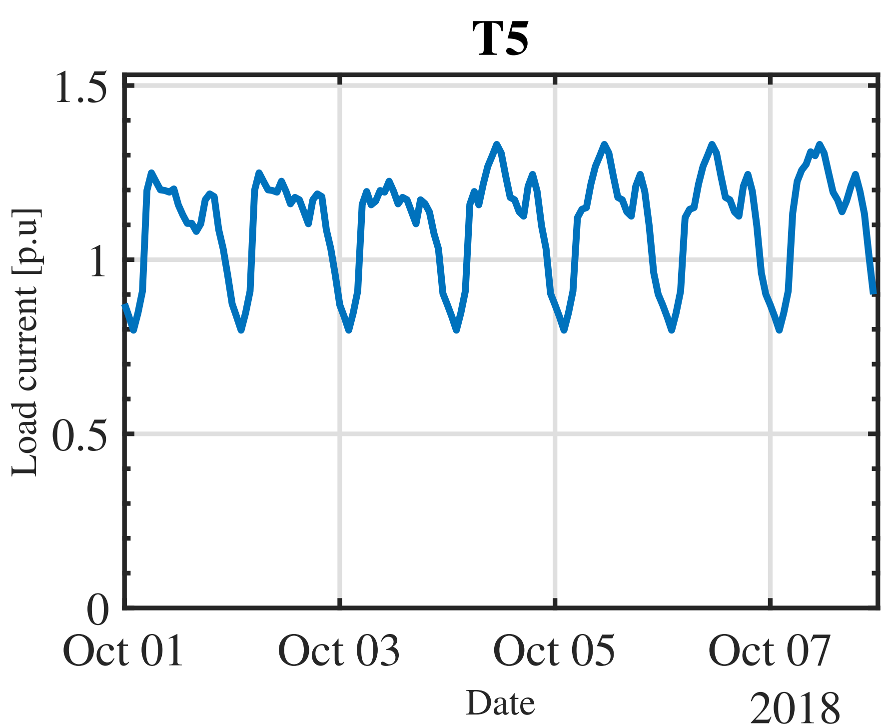


Figure A.10.: Selected week for load projection for T5 according to Table A.20

Table A.16.: Week selected for T1 load projection

Hour	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
0:00	0,06	0,07	0,07	0,09	0,07	0,06	0,06
1:00	0,07	0,07	0,07	0,09	0,07	0,05	0,08
2:00	0,07	0,09	0,07	0,09	0,07	0,06	0,07
3:00	0,06	0,09	0,07	0,07	0,07	0,06	0,07
4:00	0,06	0,08	0,06	0,07	0,06	0,06	0,07
5:00	0,06	0,08	0,06	0,08	0,06	0,05	0,07
6:00	0,05	0,08	0,05	0,08	0,05	0,04	0,07
7:00	0,05	0,08	0,06	0,08	0,06	0,05	0,07
8:00	0,07	0,08	0,06	0,09	0,07	0,05	0,08
9:00	0,08	0,07	0,06	0,08	0,07	0,05	0,08
10:00	0,09	0,08	0,05	0,07	0,07	0,06	0,08
11:00	0,08	0,09	0,06	0,06	0,07	0,05	0,08
12:00	0,08	0,08	0,05	0,05	0,06	0,05	0,07
13:00	0,08	0,08	0,06	0,06	0,07	0,06	0,08
14:00	0,08	0,08	0,06	0,06	0,07	0,06	0,08
15:00	0,08	0,08	0,08	0,05	0,07	0,07	0,08
16:00	0,08	0,08	0,08	0,05	0,06	0,07	0,08
17:00	0,08	0,08	0,08	0,05	0,04	0,07	0,07
18:00	0,09	0,08	0,08	0,06	0,07	0,08	0,05
19:00	0,09	0,09	0,09	0,07	0,07	0,08	0,06
20:00	0,08	0,09	0,09	0,08	0,07	0,08	0,06
21:00	0,07	0,09	0,09	0,08	0,08	0,06	0,06
22:00	0,06	0,08	0,09	0,07	0,08	0,06	0,06
23:00	0,06	0,09	0,09	0,07	0,06	0,06	0,04

Table A.17.: Week selected for T2 load projection

Hour	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
0:00	0,24	0,25	0,22	0,24	0,27	0,27	0,28
1:00	0,22	0,22	0,21	0,25	0,27	0,27	0,27
2:00	0,22	0,22	0,21	0,26	0,29	0,27	0,26
3:00	0,22	0,22	0,21	0,25	0,28	0,27	0,26
4:00	0,25	0,25	0,22	0,26	0,28	0,30	0,28
5:00	0,30	0,29	0,26	0,28	0,28	0,32	0,31
6:00	0,30	0,30	0,27	0,29	0,29	0,30	0,32
7:00	0,32	0,31	0,30	0,29	0,31	0,28	0,33
8:00	0,34	0,34	0,33	0,27	0,31	0,31	0,35
9:00	0,35	0,35	0,34	0,29	0,31	0,35	0,36
10:00	0,36	0,37	0,36	0,31	0,29	0,38	0,37
11:00	0,37	0,38	0,37	0,32	0,28	0,41	0,38
12:00	0,36	0,37	0,37	0,31	0,25	0,40	0,37
13:00	0,35	0,35	0,35	0,28	0,25	0,37	0,36
14:00	0,36	0,36	0,35	0,26	0,25	0,38	0,36
15:00	0,36	0,36	0,34	0,25	0,25	0,37	0,37
16:00	0,35	0,36	0,32	0,25	0,26	0,36	0,37
17:00	0,35	0,35	0,32	0,26	0,28	0,36	0,37
18:00	0,39	0,39	0,37	0,32	0,30	0,40	0,39
19:00	0,40	0,39	0,37	0,32	0,32	0,40	0,40
20:00	0,37	0,36	0,33	0,31	0,31	0,38	0,37
21:00	0,33	0,33	0,30	0,28	0,29	0,32	0,32
22:00	0,29	0,29	0,27	0,30	0,30	0,28	0,30
23:00	0,26	0,24	0,21	0,27	0,30	0,28	0,27

Table A.18.: Week selected for T3 load projection

Hour	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
0:00	0,15	0,15	0,15	0,16	0,13	0,14	0,15
1:00	0,14	0,14	0,15	0,15	0,13	0,14	0,14
2:00	0,14	0,14	0,14	0,14	0,13	0,13	0,14
3:00	0,14	0,14	0,14	0,14	0,12	0,13	0,14
4:00	0,15	0,15	0,15	0,15	0,12	0,14	0,15
5:00	0,18	0,18	0,18	0,15	0,12	0,18	0,18
6:00	0,22	0,22	0,22	0,17	0,12	0,21	0,21
7:00	0,24	0,24	0,24	0,19	0,13	0,24	0,24
8:00	0,27	0,27	0,27	0,21	0,14	0,26	0,26
9:00	0,27	0,27	0,27	0,22	0,15	0,27	0,27
10:00	0,27	0,27	0,27	0,22	0,16	0,27	0,27
11:00	0,28	0,28	0,28	0,22	0,16	0,28	0,27
12:00	0,28	0,28	0,28	0,22	0,16	0,28	0,27
13:00	0,27	0,27	0,27	0,20	0,15	0,27	0,27
14:00	0,27	0,27	0,27	0,19	0,15	0,27	0,27
15:00	0,26	0,26	0,26	0,18	0,15	0,26	0,26
16:00	0,26	0,26	0,25	0,17	0,14	0,26	0,26
17:00	0,24	0,24	0,24	0,18	0,15	0,24	0,25
18:00	0,25	0,25	0,24	0,20	0,18	0,24	0,25
19:00	0,24	0,24	0,23	0,19	0,18	0,24	0,24
20:00	0,23	0,23	0,23	0,19	0,18	0,23	0,22
21:00	0,21	0,21	0,21	0,18	0,17	0,21	0,21
22:00	0,18	0,19	0,19	0,16	0,16	0,18	0,18
23:00	0,16	0,17	0,17	0,15	0,15	0,16	0,16

Table A.19.: Week selected for T4 load projection

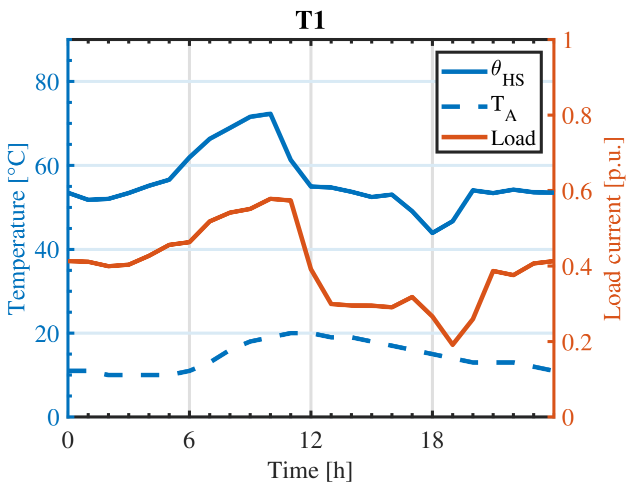
Hour	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
0:00	0,18	0,17	0,18	0,18	0,19	0,17	0,17
1:00	0,16	0,15	0,16	0,16	0,17	0,15	0,15
2:00	0,15	0,15	0,15	0,15	0,16	0,15	0,15
3:00	0,16	0,16	0,16	0,16	0,15	0,16	0,16
4:00	0,22	0,22	0,22	0,18	0,16	0,21	0,22
5:00	0,30	0,30	0,30	0,20	0,17	0,30	0,30
6:00	0,29	0,30	0,30	0,23	0,18	0,28	0,29
7:00	0,29	0,29	0,29	0,28	0,22	0,28	0,29
8:00	0,31	0,31	0,32	0,32	0,28	0,30	0,31
9:00	0,32	0,32	0,32	0,34	0,31	0,31	0,32
10:00	0,33	0,33	0,34	0,35	0,33	0,33	0,34
11:00	0,34	0,34	0,35	0,36	0,33	0,35	0,34
12:00	0,33	0,33	0,34	0,35	0,33	0,33	0,32
13:00	0,32	0,32	0,32	0,31	0,32	0,32	0,31
14:00	0,34	0,33	0,33	0,28	0,30	0,32	0,33
15:00	0,34	0,34	0,33	0,28	0,29	0,33	0,33
16:00	0,35	0,33	0,34	0,30	0,28	0,33	0,34
17:00	0,35	0,34	0,34	0,32	0,30	0,33	0,37
18:00	0,41	0,42	0,40	0,37	0,38	0,41	0,42
19:00	0,42	0,43	0,41	0,38	0,40	0,43	0,42
20:00	0,41	0,41	0,39	0,37	0,39	0,42	0,38
21:00	0,36	0,36	0,35	0,33	0,34	0,37	0,34
22:00	0,27	0,28	0,28	0,27	0,26	0,28	0,26
23:00	0,21	0,21	0,22	0,22	0,20	0,21	0,20

Table A.20.: Week selected for T5 load projection

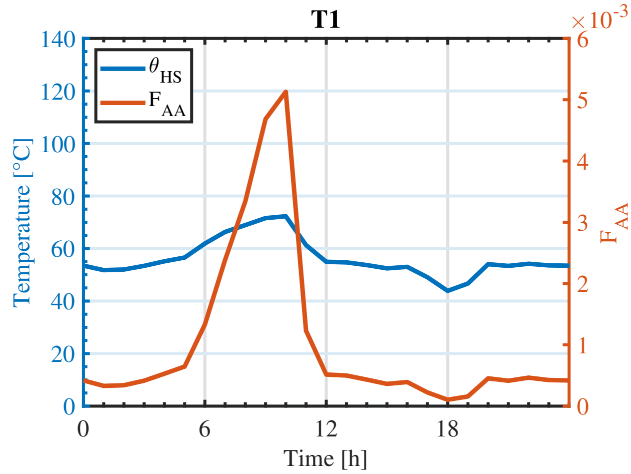
Hour	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
0:00	0,68	0,87	0,64	1,03	1,20	1,23	1,39
1:00	0,66	0,72	0,62	1,20	1,20	1,30	1,34
2:00	0,64	0,75	0,61	1,34	1,34	1,33	1,30
3:00	0,63	0,75	0,62	1,39	1,29	1,35	1,33
4:00	0,76	0,87	0,65	1,51	1,34	1,58	1,42
5:00	1,04	1,16	0,75	1,72	1,40	1,76	1,73
6:00	1,17	1,21	0,90	2,00	1,43	1,68	1,84
7:00	1,11	1,24	1,06	1,88	1,70	1,41	1,64
8:00	1,23	1,38	1,23	1,66	1,55	1,47	1,55
9:00	1,29	1,50	1,33	1,77	1,48	1,73	1,54
10:00	1,35	1,58	1,40	1,90	1,26	1,87	1,62
11:00	1,41	1,63	1,44	1,93	1,14	2,06	1,66
12:00	1,36	1,61	1,44	1,86	0,89	2,06	1,67
13:00	1,28	1,54	1,36	1,69	0,88	1,79	1,66
14:00	1,30	1,52	1,32	1,48	0,89	1,87	1,60
15:00	1,37	1,56	1,54	1,33	0,91	1,83	1,63
16:00	1,33	1,57	2,06	1,33	1,01	1,77	1,68
17:00	1,30	1,47	1,92	1,30	1,22	1,68	1,74
18:00	1,62	1,78	1,86	1,32	1,44	1,66	1,84
19:00	1,66	1,70	1,84	1,37	1,53	1,67	2,02
20:00	1,40	1,48	1,53	1,32	1,44	1,43	1,78
21:00	1,09	1,26	1,26	1,37	1,22	1,14	1,50
22:00	0,90	1,07	0,93	1,72	1,46	1,06	1,48
23:00	0,94	0,78	0,75	1,69	1,57	1,27	1,39

A.2.2. Accelerated aging factor simulation

This section presents the accelerated aging factor simulation F_{AA} presented before in Chapter 2. Equation (2.6) and Eq. (2.5) represent the heat exchange that occurs inside the power transformer while it is operating. This heat exchange depends on load current. For this, load projected in Appendix A.2.1 is used.

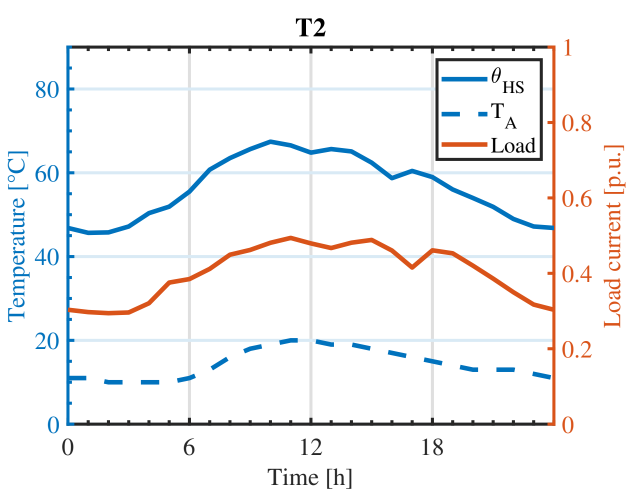


(a) T_A, θ_{HS} and load current projected for T1

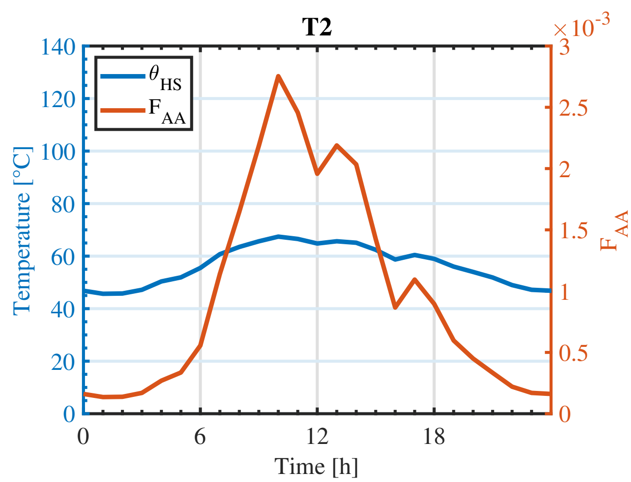


(b) θ_{HS} and F_{AA} for T1

Figure A.11.: F_{AA} simulation for T1



(a) T_A, θ_{HS} and load current projected for T2



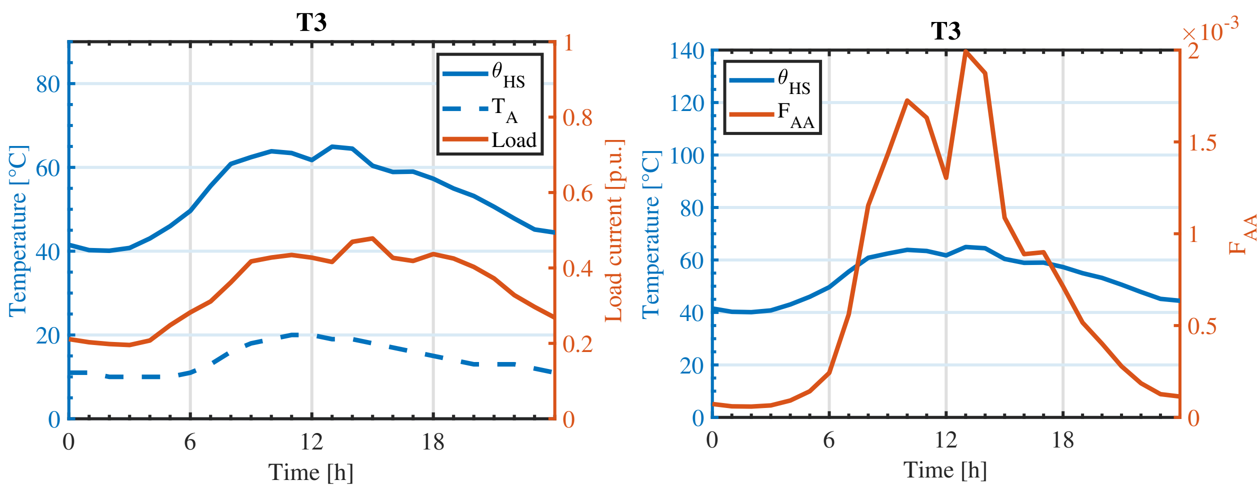
(b) θ_{HS} and F_{AA} for T2

Figure A.12.: F_{AA} simulation for T2

Figure A.11a presents θ_{HS} according to the load projected from historical data in Appendix A.2 and a profile proposed of ambient temperature T_A, as presented in Table A.21. In this case, θ_{HS} follows load current curve. Temperature peak of θ_{HS} is around 11h when transformer load current is over 0.4 p.u. and ambient temperature is at its maximum. However, this peak is around $70°C$, which is not a temperature that represents an accelerated aging for the transformer. Besides in Fig. A.11b θ_{HS} is plotted along with F_{AA}. In this figure, it is clear the exponential relationship between F_{AA} and θ_{HS}.

In Fig. A.12a it is possible to observe a similar behaviour, since load current is relatively low, θ_{HS} follows load current curve and has a maximum of temperature around $70°C$ at 10h. This peak of temperature is observed in Fig. A.12b, representing a peak in F_{AA}. Although, this behaviour of θ_{HS} does not represent an accelerated aging for the transformer. Data from Table A.22 was used for Fig. A.12a and Fig. A.12b.

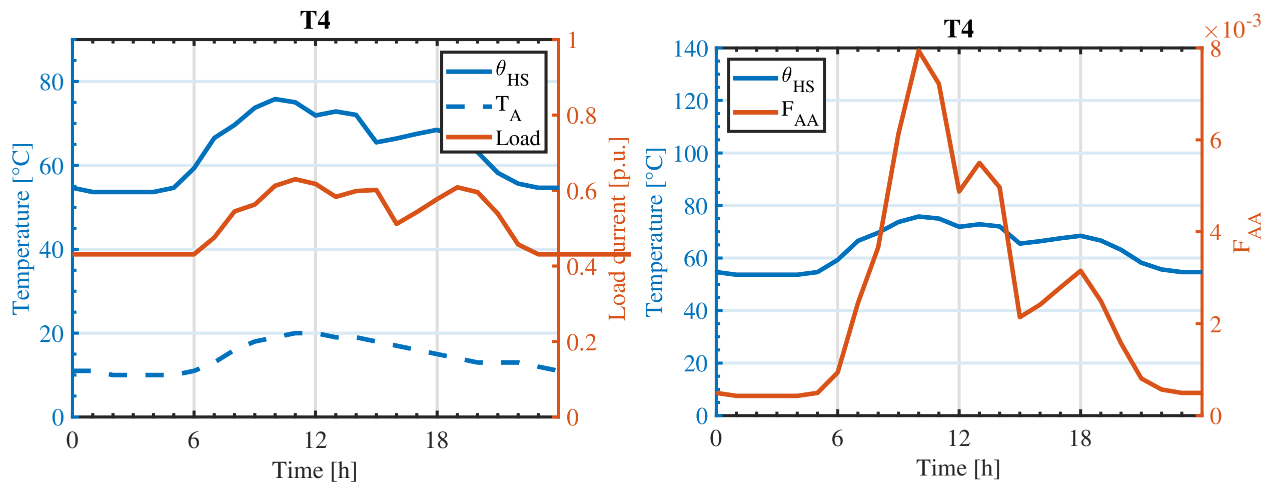
Figure A.13a presents θ_{HS} for T3 according to its load current projected as seen in Table A.23. In this case, there are two peaks of temperature θ_{HS}. These peaks are reflected in Fig. A.13b. Although, these peaks do not represent a higher value of F_{AA}.



(a) T_A, θ_{HS} and load current projected for T3 (b) θ_{HS} and F_{AA} for T3

Figure A.13.: F_{AA} simulation for T3

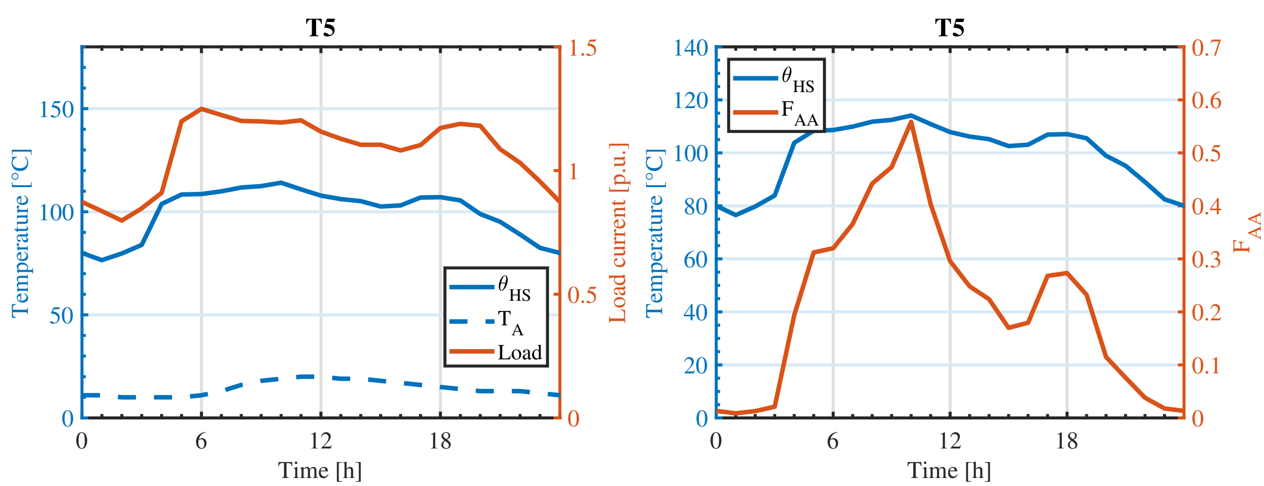
In Fig. A.14a presents θ_{HS} behaviour for T4 according to its load current projected presented in Table A.24. The corresponding F_{AA} is presented in Fig. A.14b. Although, this is not a considerable value of F_{AA}.



(a) T_A, θ_{HS} and load current projected for T4

(b) θ_{HS} and F_{AA} for T4

Figure A.14.: F_{AA} simulation for T4



(a) T_A, θ_{HS} and load current projected for T5

(b) θ_{HS} and F_{AA} for T5

Figure A.15.: F_{AA} simulation for T5

Figure A.15a presents θ_{HS} for T5. This is the case of a highly loaded transformer, which presents a θ_{HS} over $100°C$ in several hours a day. Therefore, an accelerated aging is expected for this transformer. In Fig. A.15b it is possible to observe the behaviour of F_{AA} according to θ_{HS}. These values are presented in Table A.25.

Table A.21.: F_{AA} and θ_{HS} data for T1 load projected

Hour	$T_A[°C]$	$\theta_{HS}[°C]$	F_{AA}	Load [pu]
0:00	11	53,48	4,19 E-04	0,06
1:00	11	51,78	3,30 E-04	0,07
2:00	10	52,01	3,41 E-04	0,07
3:00	10	53,41	4,15 E-04	0,06
4:00	10	55,14	5,29 E-04	0,06
5:00	10	56,57	6,46 E-04	0,06
6:00	11	61,90	1,33 E-03	0,05
7:00	13	66,32	2,39 E-03	0,05
8:00	16	68,93	3,34 E-03	0,07
9:00	18	71,58	4,68 E-03	0,08
10:00	19	72,30	5,13 E-03	0,09
11:00	20	61,31	1,23 E-03	0,08
12:00	20	54,95	5,15 E-04	0,08
13:00	19	54,73	5,00 E-04	0,08
14:00	19	53,70	4,33 E-04	0,08
15:00	18	52,45	3,63 E-04	0,08
16:00	17	53,02	3,93 E-04	0,08
17:00	16	49,07	2,23 E-04	0,08
18:00	15	43,88	1,04 E-04	0,09
19:00	14	46,68	1,58 E-04	0,09
20:00	13	54,04	4,54 E-04	0,08
21:00	13	53,39	4,14 E-04	0,07
22:00	13	54,21	4,65 E-04	0,06
23:00	12	53,58	4,25 E-04	0,06

Table A.22.: F_{AA} and θ_{HS} data for T2 load projected

Hour	$T_A[°C]$	$\theta_{HS}[°C]$	F_{AA}	Load [pu]
0:00	11	46,83	1,61 E-04	0,24
1:00	11	45,66	1,36 E-04	0,22
2:00	10	45,77	1,38 E-04	0,22
3:00	10	47,18	1,70 E-04	0,22
4:00	10	50,37	2,69 E-04	0,25
5:00	10	51,91	3,36 E-04	0,30
6:00	11	55,50	5,57 E-04	0,30
7:00	13	60,74	1,14 E-03	0,32
8:00	16	63,50	1,65 E-03	0,34
9:00	18	65,64	2,18 E-03	0,35
10:00	19	67,42	2,75 E-03	0,36
11:00	20	66,54	2,46 E-03	0,37
12:00	20	64,81	1,96 E-03	0,36
13:00	19	65,66	2,19 E-03	0,35
14:00	19	65,10	2,03 E-03	0,36
15:00	18	62,41	1,43 E-03	0,36
16:00	17	58,72	8,66 E-04	0,35
17:00	16	60,44	1,09 E-03	0,35
18:00	15	58,97	8,96 E-04	0,39
19:00	14	56,01	5,97 E-04	0,40
20:00	13	53,98	4,50 E-04	0,37
21:00	13	51,87	3,34 E-04	0,33
22:00	13	48,98	2,21 E-04	0,29
23:00	12	47,18	1,70 E-04	0,26

Table A.23.: F_{AA} and θ_{HS} data for T3 load projected

Hour	$T_A[°C]$	$\theta_{HS}[°C]$	F_{AA}	Load [pu]
0:00	11	41,51	7,30 E-05	0,15
1:00	11	40,25	6,02 E-05	0,14
2:00	10	40,11	5,89 E-05	0,14
3:00	10	40,77	6,52 E-05	0,14
4:00	10	43,04	9,19 E-05	0,15
5:00	10	45,97	1,42 E-04	0,18
6:00	11	49,63	2,42 E-04	0,22
7:00	13	55,56	5,61 E-04	0,24
8:00	16	60,83	1,15 E-03	0,27
9:00	18	62,45	1,43 E-03	0,27
10:00	19	63,85	1,73 E-03	0,27
11:00	20	63,43	1,63 E-03	0,28
12:00	20	61,75	1,30 E-03	0,28
13:00	19	64,94	1,99 E-03	0,27
14:00	19	64,48	1,87 E-03	0,27
15:00	18	60,39	1,09 E-03	0,26
16:00	17	58,91	8,89 E-04	0,26
17:00	16	58,99	8,99 E-04	0,24
18:00	15	57,29	7,13 E-04	0,25
19:00	14	54,97	5,17 E-04	0,24
20:00	13	53,17	4,02 E-04	0,23
21:00	13	50,59	2,78 E-04	0,21
22:00	13	47,80	1,86 E-04	0,18
23:00	12	45,18	1,26 E-04	0,16

Table A.24.: F_{AA} and θ_{HS} data for T4 load projected

Hour	$T_A[^{\circ}C]$	$\theta_{HS}[^{\circ}C]$	F_{AA}	Load [pu]
0:00	11	54,65	4,94 E-04	0,18
1:00	11	53,65	4,30 E-04	0,16
2:00	10	53,65	4,30 E-04	0,15
3:00	10	53,65	4,30 E-04	0,16
4:00	10	53,65	4,30 E-04	0,22
5:00	10	54,65	4,94 E-04	0,30
6:00	11	59,31	9,39 E-04	0,29
7:00	13	66,52	2,45 E-03	0,29
8:00	16	69,64	3,66 E-03	0,31
9:00	18	73,72	6,13 E-03	0,32
10:00	19	75,81	7,94 E-03	0,33
11:00	20	75,03	7,22 E-03	0,34
12:00	20	71,90	4,88 E-03	0,33
13:00	19	72,85	5,50 E-03	0,32
14:00	19	72,04	4,97 E-03	0,34
15:00	18	65,50	2,14 E-03	0,34
16:00	17	66,41	2,41 E-03	0,35
17:00	16	67,52	2,79 E-03	0,35
18:00	15	68,47	3,15 E-03	0,41
19:00	14	66,66	2,49 E-03	0,42
20:00	13	63,14	1,57 E-03	0,41
21:00	13	58,21	8,08 E-04	0,36
22:00	13	55,65	5,68 E-04	0,27
23:00	12	54,65	4,94 E-04	0,21

Table A.25.: F_{AA} and θ_{HS} data for T5 load projected

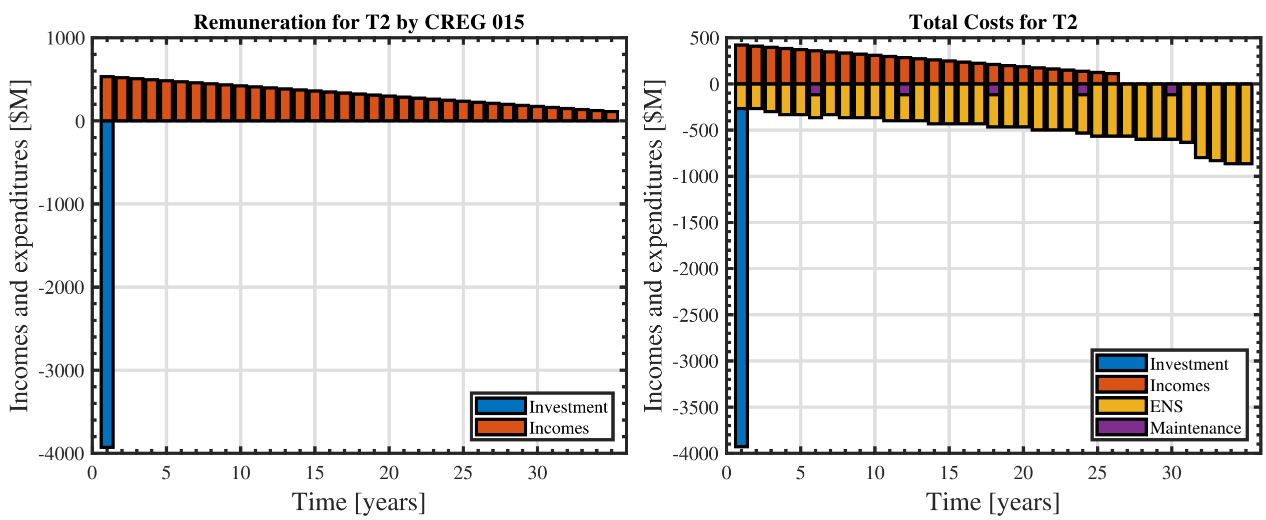
Hour	$T_A[^{\circ}C]$	$\theta_{HS}[^{\circ}C]$	F_{AA}	Load [pu]
0:00	11	80,03	1,33 E-02	0,68
1:00	11	76,53	8,67 E-03	0,66
2:00	10	79,77	1,29 E-02	0,64
3:00	10	83,92	2,11 E-02	0,63
4:00	10	103,79	1,94 E-01	0,76
5:00	10	108,37	3,12 E-01	1,04
6:00	11	108,61	3,20 E-01	1,17
7:00	13	109,91	3,66 E-01	1,11
8:00	16	111,77	4,42 E-01	1,23
9:00	18	112,44	4,73 E-01	1,29
10:00	19	114,09	5,59 E-01	1,35
11:00	20	110,87	4,03 E-01	1,41
12:00	20	107,84	2,96 E-01	1,36
13:00	19	106,15	2,48 E-01	1,28
14:00	19	105,17	2,24 E-01	1,30
15:00	18	102,56	1,70 E-01	1,37
16:00	17	103,08	1,80 E-01	1,33
17:00	16	106,89	2,68 E-01	1,30
18:00	15	107,08	2,73 E-01	1,62
19:00	14	105,52	2,32 E-01	1,66
20:00	13	98,92	1,15 E-01	1,40
21:00	13	95,14	7,60 E-02	1,09
22:00	13	89,00	3,81 E-02	0,90
23:00	12	82,49	1,78 E-02	0,94

B. Appendix B:

B.1. CREG remuneration plan analysis

In this appendix, the complement of the remuneration plan and costs associated to T2, T3, T4 and T5 are presented. These remuneration plans are based on the values of Table B.1.

The calculation of annual income depends on the investment cost that CREG recognises. This investment cost depends on the type of constructive unit (UC) as presented in Chapter 4 and according to Eq. (4.1). This investment cost is returned to the operator along 35 years with a return tax of 0.11.

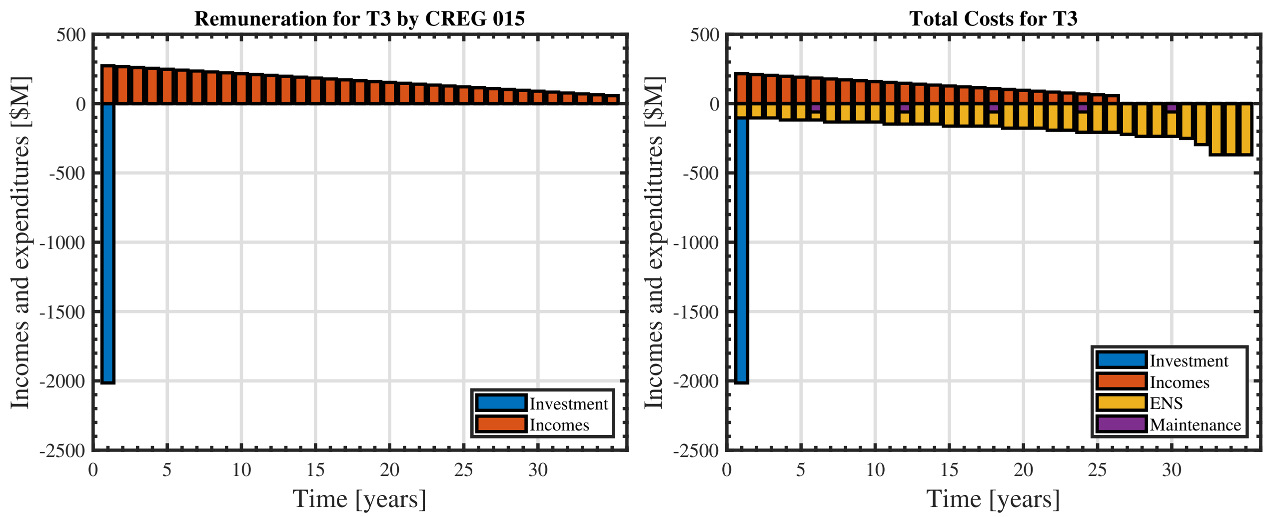


(a) Remuneration plan for T2 by CREG 015

(b) Total costs for T2

Figure B.1.: Costs considered for T2

In Fig. B.1a is presented the remuneration plan if T2 was installed after 2008, starting with an income of $532.056.197 COP in year 1, and a value of $112.248.143 in the last year. With this remuneration plan, the operator would obtain a total income of $8.671.900.000 COP in VPN by the end of year 35. However, with the adjustment, the remuneration plan for T2 is presented in Fig. B.1b where remuneration starts with a value of $408.583.240 COP. With this adjustment, the total income is $5.331.400.000 COP by the end of year 25. Maintenance cost is considered according to Section 4.1. Cost by ENS is calculated yearly according to the expected interruptions of HI simulated for T2 in Chapter 2.



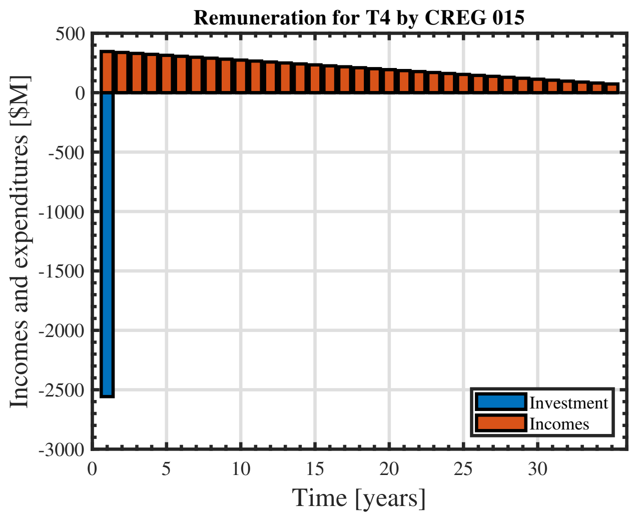
(a) Remuneration plan for T3 by CREG 015

(b) Total costs for T3

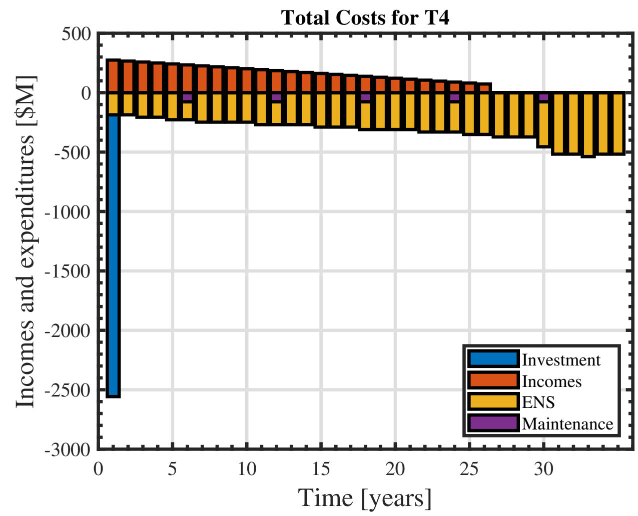
Figure B.2.: Costs considered for T3

Besides, Fig. B.2a presents remuneration plan for T3. This plan would only apply if the asset were installed before 2008, starting with an income of $272.862.705 COP in year 1, and an income of $57.565.971 in the last year. With this plan, the total income that the operator would receive for this transformer would be $4.447.300.000 COP in VPN by the end of year 35. With the adjustment, the remuneration plan for T3 is presented in Fig. B.2b where remuneration starts with a value of $209.540.136 COP in the first year, according to the values of Table B.1. The total income that the operator can receive for this transformer would be $2.734.200.000 COP in VPN by the end of year 25. Maintenance cost is also considered according to Section 4.1. The ENS cost is obtained from expected interruptions of T3 evaluated in Chapter 2.

With respect to T4, the incomes plan are presented in Fig. B.3a, where the income of year 1 is $346.380.782 COP and the income of year 35 is $73.076.114 COP. With this remuneration plan, the operator would obtain a total income of $5.645.600.000 COP in VPN by the end of year 35. The adjustment for this transformer is presented in Fig. B.3b, where the first remuneration received corresponds to the income of year 11: $265.997.056, as seen to Table B.1. The total income that the operator can received is $3.470.900.000 COP in VPN by the end of year 25. Maintenance and ENS costs are considered in the same way as T3 according to Section 4.1. The ENS cost is estimated in the same way of the other sample transformers presented in Chapter 2.

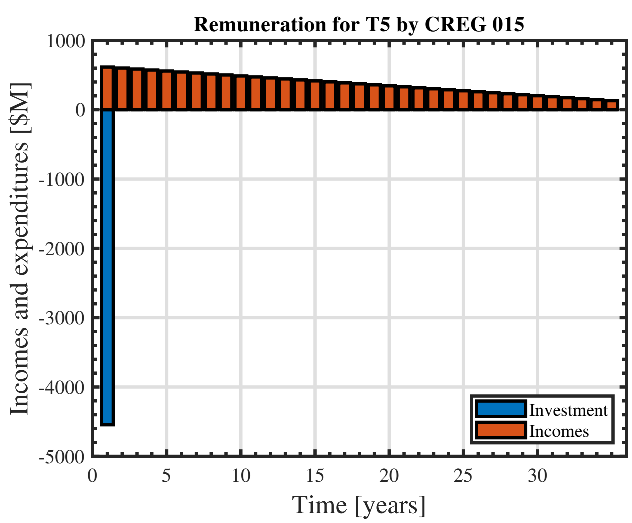


(a) Remuneration plan for T4 by CREG 015

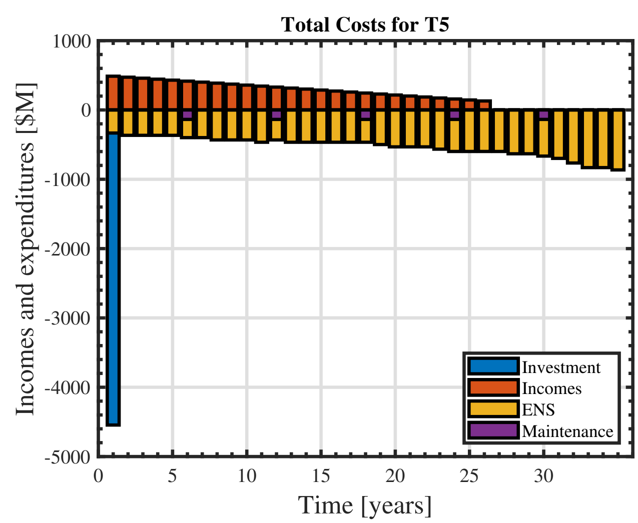


(b) Total costs for T4

Figure B.3.: Costs considered for T4



(a) Remuneration plan for T5 by CREG 015



(b) Total costs for T5

Figure B.4.: Costs considered for T5

Finally, T5 plan remuneration plan along 35 years is presented in Fig. B.4a. This plan starts with an income of \$615.548.724 COP if the asset were installed after 2008. For this remuneration plan, the maxium total income that the operator could received would be \$10.033.000.000 COP in VPN by the end of year 35. Since the case is the opposite, the real remuneration plan is presented in Fig. B.4b, where the first income is \$472.699.864 and the last income is \$129.862.600 according to the values of Table B.1. The maximum total remuneration can be obtained by the end of year 25 and has a VPN value of \$6.168.100.000 COP.

Table B.1.: Annual incomes for sample transformers according to 015 CREG [1] (Part I).

Year	Annual remuneration				
	T1	T2	T3	T4	T5
1	$ 155.124.084	$ 532.056.197	$ 272.862.705	$ 346.380.782	$ 615.548.724
2	$ 151.524.158	$ 519.708.901	$ 266.530.448	$ 338.342.409	$ 601.263.838
3	$ 147.924.232	$ 507.361.606	$ 260.198.191	$ 330.304.037	$ 586.978.952
4	$ 144.324.306	$ 495.014.310	$ 253.865.934	$ 322.265.664	$ 572.694.066
5	$ 140.724.380	$ 482.667.014	$ 247.533.677	$ 314.227.291	$ 558.409.180
6	$ 137.124.454	$ 470.319.719	$ 241.201.420	$ 306.188.919	$ 544.124.294
7	$ 133.524.528	$ 457.972.423	$ 234.869.163	$ 298.150.546	$ 529.839.408
8	$ 129.924.602	$ 445.625.127	$ 228.536.907	$ 290.112.174	$ 515.554.522
9	$ 126.324.676	$ 433.277.831	$ 222.204.650	$ 282.073.801	$ 501.269.636
10	$ 122.724.750	$ 420.930.536	$ 215.872.393	$ 274.035.429	$ 486.984.750
11	$ 119.124.824	$ 408.583.240	$ 209.540.136	$ 265.997.056	$ 472.699.864
12	$ 115.524.898	$ 396.235.944	$ 203.207.879	$ 257.958.683	$ 458.414.978
13	$ 111.924.972	$ 383.888.649	$ 196.875.622	$ 249.920.311	$ 444.130.092
14	$ 108.325.046	$ 371.541.353	$ 190.543.365	$ 241.881.938	$ 429.845.206
15	$ 104.725.120	$ 359.194.057	$ 184.211.109	$ 233.843.566	$ 415.560.320
16	$ 101.125.194	$ 346.846.761	$ 177.878.852	$ 225.805.193	$ 401.275.434
17	$ 97.525.268	$ 334.499.466	$ 171.546.595	$ 217.766.821	$ 386.990.548
18	$ 93.925.342	$ 322.152.170	$ 165.214.338	$ 209.728.448	$ 372.705.662
19	$ 90.325.416	$ 309.804.874	$ 158.882.081	$ 201.690.075	$ 358.420.776
20	$ 86.725.490	$ 297.457.579	$ 152.549.824	$ 193.651.703	$ 344.135.890
21	$ 83.125.564	$ 285.110.283	$ 146.217.567	$ 185.613.330	$ 329.851.004
22	$ 79.525.638	$ 272.762.987	$ 139.885.311	$ 177.574.958	$ 315.566.118
23	$ 75.925.712	$ 260.415.691	$ 133.553.054	$ 169.536.585	$ 301.281.232
24	$ 72.325.786	$ 248.068.396	$ 127.220.797	$ 161.498.213	$ 286.996.346

Table B.2.: Annual incomes for sample transformers according to 015 CREG [1] (Part II).

Year	Annual remuneration				
	T1	T2	T3	T4	T5
25	$ 68.725.860	$ 235.721.100	$ 120.888.540	$ 153.459.840	$ 272.711.460
26	$ 65.125.934	$ 223.373.804	$ 114.556.283	$ 145.421.467	$ 258.426.574
27	$ 61.526.008	$ 211.026.509	$ 108.224.026	$ 137.383.095	$ 244.141.688
28	$ 57.926.082	$ 198.679.213	$ 101.891.769	$ 129.344.722	$ 229.856.802
29	$ 54.326.156	$ 186.331.917	$ 95.559.513	$ 121.306.350	$ 215.571.916
30	$ 50.726.230	$ 173.984.621	$ 89.227.256	$ 113.267.977	$ 201.287.030
31	$ 47.126.304	$ 161.637.326	$ 82.894.999	$ 105.229.605	$ 187.002.144
32	$ 43.526.378	$ 149.290.030	$ 76.562.742	$ 97.191.232	$ 172.717.258
33	$ 39.926.452	$ 136.942.734	$ 70.230.485	$ 89.152.859	$ 158.432.372
34	$ 36.326.526	$ 124.595.439	$ 63.898.228	$ 81.114.487	$ 144.147.486
35	$ 32.726.600	$ 112.248.143	$ 57.565.971	$ 73.076.114	$ 129.862.600
VPN	$ 2.528.300.000	$ 8.671.900.000	$ 4.447.300.000	$ 5.645.600.000	$ 10.033.000.000

C. Appendix C: Papers published under the thesis framework

Papers published under the framework of this thesis will be shown below.

C.1. Forecasting of power transformer life loss under Maintenance and Demand Side Management Scenarios

Presented at 2017 Simposio Internacional sobre la Calidad de la Energía Eléctrica - SICEL. Bucaramanga, Colombia. ISSN: 2357-6618.

URL: `https://revistas.unal.edu.co/index.php/SICEL/article/view/63719`.

C.2. Analysis of Maintenance in Transformers Based on a Fuzzy Logic Method

Presented at 2018 IEEE PES Transmission & Distribution Conference and Exhibition - Latin America (T&D-LA). Lima, Perú. DOI: 10.1109/TDC-LA.2018.8511772

URL: `https://ieeexplore.ieee.org/document/8511772`.

C.3. A Framework For Asset Management in Electrical Systems, Part I: Conceptual Model

Presented at 2019 IEEE Workshop on Power Electronics and Power Quality Applications (PEPQA), Manizales, Colombia. DOI: 10.1109/PEPQA.2019.8851575

URL: `https://ieeexplore.ieee.org/document/8851575`.

C.4. A Framework For Asset Management in Electrical Systems, Part II: Case Study - Power Transformers

2019 IEEE Workshop on Power Electronics and Power Quality Applications (PEPQA), Manizales, Colombia. DOI: 10.1109/PEPQA.2019.8851551

URL: https://ieeexplore.ieee.org/document/8851551.