**National Grid Electicity Transmission Network Asset Risk Annex for RIIO-T2**

NARA-T2    I    Issue 6

**02/12/2022**

## Issue Record

| Issue | Date | Summary of Changes |
|---|---|---|
| 1 | 30/04/2018 | Ofgem Submission |
| 2 | 18/05/2018 | Public Consultation |
| 3 | 29/06/2018 | First live version |
| 3.1 | 02/11/2018 | Incorporating changes following Calibration, Testing & Validation (CTV) |
| 4 | 24/08/2020 | Updates to system consequence and OHL scoring methods |
| 5 | 25/03/2020 | Update to CB C1 factor. Updates to Cable scoring method. New material concerning application of Long Term Risk Benefit |
| 6 | 02/12/2022 | Major update of document including:<br>• Transfer to new document template<br>• New introductory material<br>• Merge of Licensee-specific appendices into main text following NARM Methodology Review exercise<br>• Obsolete references to NOMs replaced with NARM |

# Contents

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## Purpose

This document outlines the role of Monetised Risk in the context of providing a quantified, consistent, and measured approach to network investment. The use of Monetised Risk has implications for the measurement of the Output elements of the RIIO-T2 framework. This document also captures certain key assumptions concerning the use of the Monetised Risk framework.

This Network Asset Risk Annex describes the calculation and application of Monetised Risk for the below asset categories:

- Circuit Breakers
- Transformers
- Reactors
- Underground Cables (Transmission)
- Overhead Line Fittings

The Network Asset Risk Metric is designed to demonstrate that the TOs are targeting investment in the right areas to manage network risk effectively, ensuring that the TO will continue to deliver primary outputs and a network that is fit for purpose in the future.

As network investment takes place over the longer term, there would be a time lag before any under-investment in the assets would impact the primary outcomes (reliability and delivery of power). For example, if an asset is not replaced when required, it may be some time until the asset fails and impacts network reliability. Using NARM, the Licensees can identify and prioritise interventions to maintain a safe and reliable network.

For the RIIO-T2 price control period which covers the five years from 1 April 2021 to 31 March 2026, Special Condition 9.2 sets out the requirements of the licensee in respect of the NARM Methodology. It also sets out the process for modifying the NARM Methodology during the RIIO-T2 price control period.

This document sets out sections covering areas of the NARM application.

Boxes like this contain key information about a section.

# 1 The Network Asset Risk Metric objectives

The NARM objectives are detailed in the NARM Common Methodology and listed below for reference.

- To allow Ofgem and other stakeholders to understand the links between the data that a network company collects and utilises and the asset management and investment decisions it makes.

- To enable Ofgem to set outputs for the network company to deliver over a price control period and to ensure that what the network actually delivers can be compared to the targets on a like-for-like basis.

- To enable the network company to estimate the Monetised risk of its network assets both now and in the future.

- To enable the network company to estimate the monetised risk benefit that would be delivered by different types of interventions on any given asset or group of assets. The objective is to be able to estimate single year snapshot risk, and long-term risk benefit.

- The estimated monetised risk benefits should be suitable for use as inputs in Cost Benefit Analyses (CBA) in order to help network companies, choose the best value for money investments, and to demonstrate to Ofgem, consumers and other stakeholders that any investment plans have been optimised. This means that the Monetised Risk Benefits should be realistic with robust probability estimates and correctly valued consequences.

- To enable the identification and quantification of drivers of changes in Monetised Risk over time.

- To allow Monetised risk comparisons to be made between different assets and different networks. In order for this objective to be achieved, the methodologies used for estimating monetised risk should be based as little as possible on subjectivity.

- To enable the network company to report to Ofgem and other stakeholders in a way that can be easily understood and unambiguously interpreted.

## 2 The Network Asset Risk Annex (NARA) Objectives

NARA-T2 describes the National Grid ET implementation of the Network Asset Risk Metric (NARM). This document has been renamed to differentiate it from NARA-Future Price Control. It is proposed to separate future development material for future Price Controls from NARA-T2.

The primary objective of this update of NARA-T2 is to provide an explanation of the mechanics of NGET's risk model, which is used to achieve the NARM objectives. This is intended to aid stakeholders in their understanding of the current practice, and for changes to be developed for NARA-Future Price Control. Callout boxes like this are shown throughout this document to highlight important features.

Issue 6 of NARA-T2 represents our ongoing efforts to review and improve the NARM Methodology to better facilitate the NARM objectives in accordance with Licence Special Condition 9.2.6. As part of our commitment to continuous improvement, we will continue to develop the NARM methodology and associated documents to provide greater transparency in methodology and models utilised within NARM.

In consultation with both Ofgem and the other Transmission Licensees, we have agreed objectives for issue 6. These include:

- The consolidation of licensee-specific and calibration, testing & validation process into the main body of the document where possible.
- The presentation of worked examples in relevant sections. This is intended to reduce the need for cross-referencing,
- Minimal material is now redacted to the License Specific Appendices where, for example, it may be commercially sensitive. This is intended to reduce the need for cross-referencing.
- The change process for NARA-T2 and NARA-Future Price Control is to be documented.
- Discussion of where the NGET NARA differs with that of other TO's, to align better to those operators where possible, and outline the reasons for differences where they are necessary.

# 3 Introduction

This document is intended to be read in conjunction with the NARM Common Methodology.

## 3.1 National Grid Electricity Transmission

NGET owns the high voltage electricity transmission system in England & Wales. It is primarily comprised of equipment operating from 400 to 132kV; and consists of approximately

- 14,000 kilometres of overhead lines
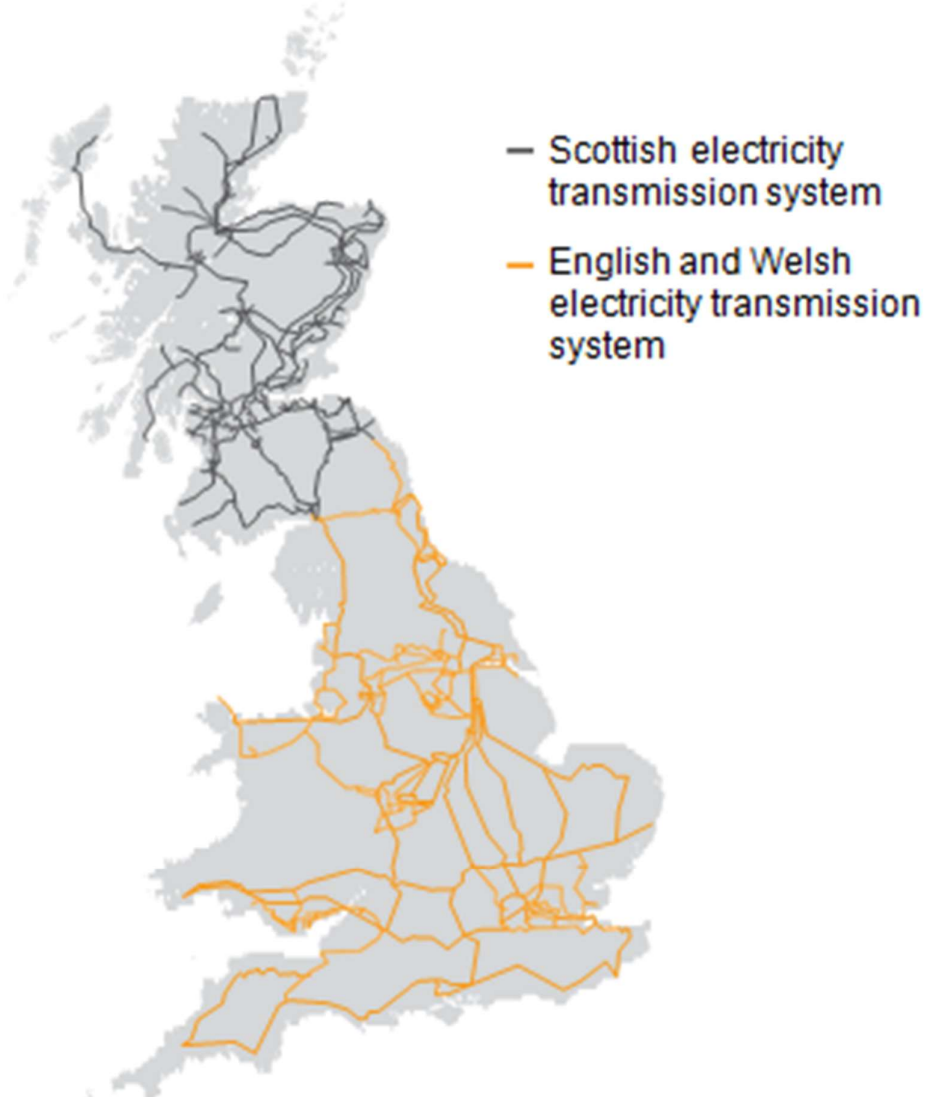- 600 kilometres of underground cables
- Over 300 substations



— Scottish electricity transmission system

— English and Welsh electricity transmission system

**Figure 1**

## 3.2 Introduction to Risk

The formal assessment of risk is a useful tool in managing complex systems. NARM is part of NGET's decision support framework. It has bearing on what interventions (e.g. maintenance, replacements) take place on the network.

Risk is part of our everyday activities. Whether it is crossing the road or driving our car, we take risk. For these everyday activities we often do not consciously evaluate the risks, but we do take actions to reduce the chance of risk materialising and/or the impact if it does. To reduce the chance of crashing into the car in front, we may try to leave ample stopping distances for the conditions or reduce the impact should a crash happen by fastening our seat belts. These actions are examples of how you can manage risk through mitigation: the risk is modified by action.

Risks represent threat to organisational objectives, for example keeping their staff, contractors and public safe; environmental threats, or the provision of services. A formal process of identifying and evaluating risk and consequence is a useful tool in informing future investment decisions.

The International Organisation for Standardization (ISO) published guidance on asset and risk management; *ISO31000:2009, Risk Management – Principles and Guidelines*; and *ISO55001 Asset Management.* These documents provide guidance on establishing a common basis for identifying, analysing, and modifying risk. *BS EN 60812:2006 Analysis Techniques for System Reliability* provides useful guidance on application of analysis techniques to risk management. Throughout the methodology and NARA-T2, relevant content from these standards have been adopted, including their vocabulary[1]. Some key definitions follow:

| Risk | Effect of uncertainty on objectives |
|---|---|
| Risk management | Coordinated activities to direct and control an organization with regard to risk |
| Event | Occurrence or change of a particular set of circumstances |
| Likelihood | Chance of something happening |
| Consequence | Outcome of an event affecting objectives |
| Level of risk | Magnitude of a risk or combination of risks, expressed in terms of the combination of consequences and their likelihood |

**Table 2**

Risk is often expressed in terms of a combination of the likelihood of an event (including changes in circumstances) and the consequences of the event. Likelihood of an event can be defined mathematically in the form of a probability, or frequency over time; or qualitatively e.g. low/medium/high. While objective measures can be derived for some failure modes, others may have to be defined qualitatively. Small asset populations, or relatively new asset types are likely to lack statistical evidence to describe behaviour thus alternatives must be used.

Similarly, the consequences of an event can be certain or uncertain and can have positive or negative effects on objectives. These again, can be expressed qualitatively or quantitatively.

A single event can lead to a range of consequences, and initial consequences can escalate through knock-on effects. The events of 9th August 2019 culminating in the disconnection of demand are an example of how unrelated single events (lightning) can create the conditions for other events (unplanned disconnection of generation) with resulting consequences.

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[1] *The reproduction of the terms and definitions contained in this International Standard is permitted in teaching manuals, instruction booklets, technical publications, and journals for strictly educational or implementation purposes. The conditions for such reproduction are: that no modifications are made to the terms and definitions; that such reproduction is not permitted for dictionaries or similar publications offered for sale; and that this International Standard is referenced as the source document.*

The combination of likelihood and consequence may be expressed in a risk matrix, where likelihood is placed on one axis, and consequence on the other. The combination of likelihood and consequence might be expressed as:

$$Risk = Likelihood * Consequence$$

**Equation 1**

Noting that if a qualitative scale is chosen, the output of equation 1 might be "Low/Medium/High" multiplied by the consequences.

When using the likelihood expressed as a probability and consequences in terms of costs, using the risk equation returns results in the form of a risk cost. Equation 1 is a utility function which provides a view of the relative risk between other items calculated on a similar basis.

This risk cost is *not* a real pounds value and cannot be directly compared to financial benefits of a decision. A low-risk item may still require intervention to comply with statutory requirements, such as the Pressure System Safety Regulations, or the Electricity at Work Act.

The downstream use of Risk within RIIO-T2 in the context NARM objective 5 must remain cognisant of the capabilities and limitations of the tooling applied. Risk is a decision support tool, and other factors may be taken into account to reach the final decision.

## 3.3 Stakeholder Engagement and Change Process for NARA-T2

Changes to the methodology are appropriately documented, and those that impact future price control periods are documented separately. We consult with our stakeholders to shape the methodology and reflect their views.

NARA-T2 is published on National Grid's website: https://www.nationalgrid.com/nara

The NARA as an adjunct to the NARM Handbook and Common Methodology is effectively an extension of the Transmission License. Change is therefore governed by similar processes. To facilitate development of the NARA and Common Methodology for Future Price Controls, changes applicable to the current regulatory period shall be contained in NARA-T2. Future change will be documented in a separate release of the document, NARA-Future Price Control. This is to enable development of the methodology without undue impact on T2.

Where a new release is proposed; the new material will be presented on the website for at least one month.

We engage with our stakeholders to effectively understand and reflect the priorities of our stakeholders in our asset intervention assessments, using NARM, which feeds into our network planning, development, and operations. We consider a stakeholder in line with AccountAbility's[2] definition of 'any individual, group of individuals, or organisations that affect and/or could be affected by [our] activities, products or services, and/or associated performance'.

Our stakeholder groups include:
• Enablers such as the regulator, government departments, National Grid ESO.
• Members of the public.
• Specialist influencer such as industry partners, local authorities, network owners.
• Communities both local and regional.
• Infrastructure and emergency response.
• Customers such as electricity generators, distribution network owners, large demand customers.

[2] AA1000 Stakeholder Engagement Standard (AccountAbility, 2015) available at:
https://www.accountability.org/wp-content/uploads/2016/10/AA1000SES_2015.pdf

We would seek to engage with our stakeholders when changes to the NARM methodology are proposed or being developed. When engaging on the NARM methodology, we carry out a mapping exercise to identify the relevant stakeholders, and those who are best placed to provide insight on the proposed methodology updates. Understanding the stakeholders' knowledge level, of the content, allows us to tailor our engagement, to get the best responses. Stakeholder feedback is collected and presented in a report that is submitted to the Authority. The feedback is then used to shape the methodology, with the documentation and methodology revised where necessary.

# 4 Introduction to NGET Risk Calculation Methodology

This section sets out the formal definitions of terms used throughout the methodology.

The NARM Common Methodology and NGET License Special conditions require the evaluation of risk for the 'NARM asset categories' which are:

- Circuit Breakers
- Transformers
- Reactors
- Underground Cables (Transmission)
- Overhead Line Fittings

Methods for calculating risk for Overhead Line Conductor is included in NARA-T2. The reporting of completion of OHL conductor work is via a price control deliverable mechanism rather than related to NARM output, though NARM RRP does also report risk for Conductors.

Often, one or two dominant failure modes contribute to the majority of risk on an asset; that is, the fastest-deteriorating components define the intervention requirements. Lesser failure modes can be inconsequential in the context of intervention planning, noting that at the point of necessary intervention the opportunity would be taken to address lesser failure modes where required.

There is limited benefit to exhaustive analysis of failure modes in the context of risk. It is not feasible to define every possible failure mode and consequence. For example, third party damage to the assets is not considered in the analysis, for this has no bearing on defining maintenance or replacement decisions.

Assessment is driven primarily by the materiality and consequential information sets derived from experience of owning and operating such assets. High-impact, low-probability events are generally out of scope of utilising Monetised Risk. Negligible likelihood multiplied by infinite consequences produce give a mathematically undefined output. Similarly, the number of possible high-impact low probability scenarios cannot be usefully bound for purposes of assessing risk.

The NGET implementation of this methodology considers failure modes which have been explored in detail, supported by historical data where available; and estimated where it is not.

## 4.1 Asset (A)

An asset is defined as a unique instance of one of the above five types of assets. Overhead line and cable routes will be broken into appropriate segments of the route. Each asset belongs to an asset family, and each asset family has one or more failure modes. A failure mode can lead to one or more consequences.

## 4.2 Material Failure Mode (F)

A failure mode is a distinct way in which an asset or component may fail. Material failure modes are those considered to be materially significant; only material failure modes are considered in the risk calculation methodology. Failure means it no longer does what it is designed to do and has a significant probability of causing a material consequence. Each failure mode is mapped to one or more failure mode effects.

The list of failure modes modelled is not exhaustive for it is not feasible to catalogue every possible issue; an intervention for previously unmodelled criteria are therefore always within the realms of possibility.

A given failure mode ($F_i$) is mapped to at least one consequence ($C_j$) and a conditional probability that the given consequence will manifest should the failure occur $P(C_j \mid F_i)$.

## 4.3 Probability of Failure P(F)

The probability of failure represents the probability that a failure mode will occur in the next time period. It is generated from an underlying parametric probability distribution, or failure curve. The nature of this curve and its parameters (i.e. increasing or random failure rates, earliest and latest onset of failure) are provided by Failure Modes and Effects Analysis (FMEA). The probability of failure is influenced by a number of factors, including time, duty, and condition. The detailed calculation steps to determine probability of failure are described within this document.

## 4.4 Probability of Detection and Action P(D)

There is a probability that the failure mode may be detected through inspection and action taken before there is a consequence. This is denoted by $P(D_i)$ for a given failure mode, *i*.

The probability of detection and action is included for completeness; however it is not currently included within NGET's Risk Model.

There are a number of techniques that may be used to detect certain failure modes, and these have been captured in the FMEA:

| Detection Technique | Activity |
|---|---|
| Periodic inspection | Routine inspection of asset at set intervals. |
| Alarm/indication/ metering | Automatic systems that monitor certain parameters on equipment and provide an automatic alert, e.g. cable oil pressure monitoring detects the possibility of an oil leak. |
| Sample monitoring | Periodic sampling to establish specific parameters to determine health of asset, e.g. oil sampling on transformers. |
| Continuous monitoring | Monitoring equipment installed on specific assets whereby data about their health is recovered, logged, trended, and monitored autonomously. Alerts are generated when thresholds are breached, or when a parameter exceeds X% in a specified time frame, e.g. Mobile Transformer Assessment Clinic. |
| Periodic operation | Planned operation to ensure that the asset/components/mechanisms function as expected, e.g. periodic operation of circuit breakers. |

**Table 3**

# 5 Consequence (C)

This section defines how Consequence Probabilities are calculated.

For the calculation of asset risk, each of the underlying system, safety, environmental and financial components are assigned a consequence. This is expressed in financial terms. Each $C_j$ has one or more $F_i$ mapped to it. A consequence can be caused by more than one failure mode, but a consequence itself can only occur once during the next time period. That is, an asset or particular component is irreparably damaged only once.

## 5.1 Probability of Consequence P(D)

If Consequence *j* can be caused by *n* failure modes, then the probability of consequence P($C_j$) occurring in the next time interval is given by:

$$P(C_j) = 1 - \prod_{i=1}^{n}(1 - P(F_i) \times P(C_j|F_i) \times (1 - P(D_i))$$

**Equation 2**

where:
$P(C_j) = Probability\ of\ consequence\ j\ occurring\ during\ a\ given\ time\ period$
$P(F_i) = Probability\ of\ failure\ mode\ i\ occurring\ during\ the\ next\ time\ interval$
$P(C_j|F_i) = Conditional\ probability\ of\ Consequence\ j\ given\ F_i\ has\ occurred$
$P(D_i) = Probability\ of\ detecting\ failure\ mode\ i\ and\ acting\ before\ C_j\ materialises$

However, where failure modes and consequences have a one-to-one mapping i.e. the given consequence will definitely occur if the failure mode occurs, the function P(Cj | Fi) is not required : the Probability of Failure is equal to the Probability of Consequence.

# 6 Asset Risk

**This section defines how Asset Risk and Network Risk are calculated.**

The measure of Asset Risk for a given asset (A) is defined as AR and given by:

$$AR = \sum_{j=1}^{n} PoF_j \times CoF_j$$

**Equation 3**

Where:

$PoF_j = Probability\ of\ Failure\ j\ occurring\ during\ a\ given\ time\ period$
$CoF_j = the\ monetised\ Consequence\ of\ Failure\ j$
$n = the\ number\ of\ failures\ associated\ with\ Asset$

The NGET NARA modifies this slightly. For a given asset $k$, a measure of the risk associated with it is the Asset Risk ($A_k$), given by:

$$Asset\ Risk\,(A_k) = \sum_{j=1}^{n} P(C_j) \times\ C_j$$

**Equation 4**

Where:

$P(C_j) = Probability\ of\ consequence\ j\ occurring\ during\ a\ given\ time\ period$
$C_j = the\ monetised\ Consequence\ j$
$n = the\ number\ of\ Consequences\ associated\ with\ Asset\ k$

Figure 2 shows how the many components interact and combine to arrive at a value for an Asset Risk.
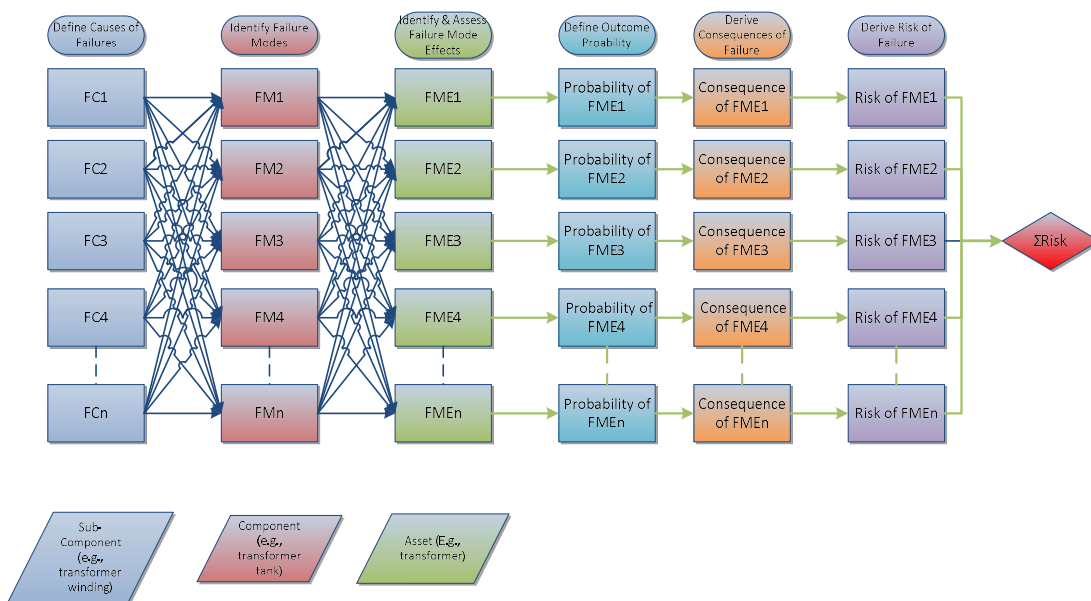


**Figure 2**

## 6.1 Network Risk

As shown in Figure 2 & Equation 4, the asset risk is a function of the probability of each failure mode occurring, and the impact of each of the consequences.

Network risk for NGET can be calculating by summing the asset risks associated with each of the lead assets as shown in equation 5.

$$Network\ Risk = \sum_{k=1}^{n} A_k$$

Equation 5

# 7 Methodology for Calculating the Probability of Failure

This section discusses techniques used to calculate the probability of failure. The forecast probability of failure is important to regulatory reporting during RIIO-T2, and it is an input to calculation of Long-term Risk Benefit.

Probability of failure represents the likelihood that a failure mode will occur in the next time period. It is denoted by P(F$_i$), the probability of failure mode *i* occurring during the next time interval is given by:

$$P(F_i) = S_t - S_{t+1}$$

**Equation 5**

Where:
$P(F_i) = the\ probability\ of\ failure\ mode\ i\ occurring\ during\ the\ next\ time\ interval$
$S_t = the\ cumulative\ probability\ of\ survival\ until\ time\ t$
$S_{t+1} = the\ cumulative\ probability\ of\ survival\ until\ time\ t+1$

S$_t$ denotes the likelihood that failure does not occur until at least time *t.* It is generated from an underlying parametric probability distribution or failure curve. The nature of this curve and its parameters (i.e. increasing or random failure rate, earliest and latest onset of failure) are provided by the process known as Failure Modes and Effects Analysis (FMEA) as described in BS EN 60812. The probability of failure is influenced by time, duty, and condition.

## 7.1 Define Causes of Failure

Failure may be defined and categorised in different ways. For the purposes of NGET's FMEA, we consider three basic types of failure:

Time-based failure (potential to functional failure). This assumes that the patterns of failure are predictable within an interval between initiation (potential) and failure. Inspection activities may be available to identify the development of the failure cause after initiation. Time-based failures are represented within the model with an earliest and latest expected onset of failure based on the time that has elapsed following the last intervention (for example, maintenance).

Utilisation failure. Failure is based on duty with a predictable 'useful life' for the component. A preventative intervention can be undertaken, if this useful life is understood, which can be scheduled before failure occurs. For example, these assets may have a known number of operations and are represented by the number of expected operations to failure since the last intervention addressing the particular failure mode.

Random failure. These failures have a constant failure rate, when observed over large enough populations or sufficient periods of time. They are usually expressed as a percentage per annum for the population.

Failure causes are usually determined by analysis of failed assets, testing, and expert's knowledge.

## 7.2 Identify failure modes

There are a number of potential causes of asset failure. These can lead to many different failure modes, which in turn lead to one or more events. Every asset will have many different failure modes, consideration of the range of failure modes associated with a circuit breaker, for example, may resemble figure 3.
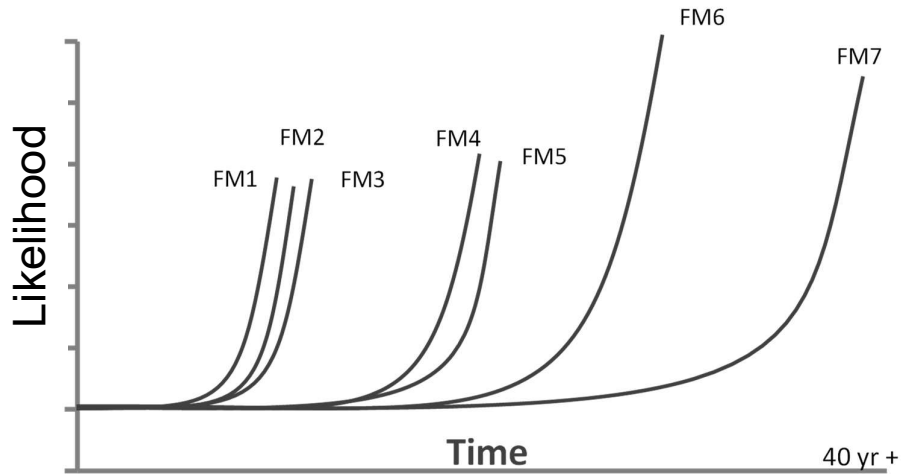
**Figure 3**

Examples might include

| FM1 | Failure to trip |
| --- | --- |
| FM2 | Failure to open |
| FM3 | Failure to complete operation |
| FM4 | Failure to close |
| FM5 | Failure to respond to control signal |
| FM6 | Flashover |
| FM7 | Loss of Containment |

**Table 4**

The level of detail in the analysis (and number of relevant failure modes) is an important consideration. Section 5.2.2.3 of BS EN 60812 provides useful guidance in this area, recognising that the number of failure modes for consideration will be influenced by previous experience. Less detailed analysis is justified for systems of mature design, good reliability, maintainability, and safety record. In addition, the requirements of asset maintenance and repairs are valuable to determining the necessary level of detail.

## 7.3 Understanding Failure Modes and How Interventions Impact Asset Risk

Figure 4 shows a simplified example of an asset that has two failure modes (FM1 and FM2). The blue line represents the asset's risk position with time. The risk position on the y axis represents the risk associated with the relevant failure mode. The total asset risk would be calculated as stated in equation 3.
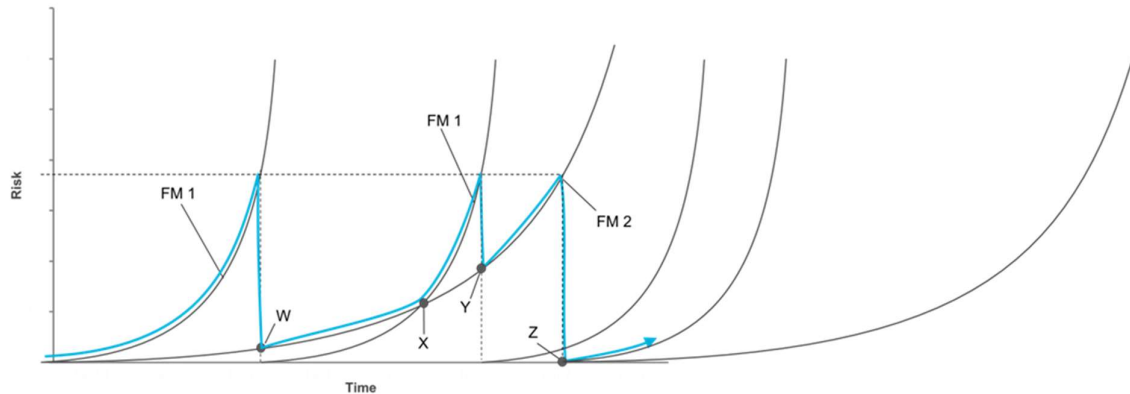


**Figure 4**

An intervention addresses one or more failure modes, either resetting or partially resetting that failure mode but leaving others unchanged.

As time progresses the asset risk increases because the probability of FM1 increases. Eventually the risk reached a specified level, and an intervention is conducted which fully addresses FM1. It does not affect FM2.

As the degradation curve for FM1 is much steeper than FM 2 it intersects with FM1's curve at point 'X' and so a transition to being FM1 driven commences again. When the risk becomes too great, another intervention is undertaken returning the risk to point 'Y' on FM2's curve. The risk then increases along FM2 until a limit is reached. At this point, because of the nature of FM2 (for example, it may be the degradation of a core component through wear) totally replacing the asset becomes necessary and this will therefore reset both failure modes to point 'Z'.

When carrying out an intervention, a number of factors need to be considered in addition to the asset risk; the intervention should address the relevant failure mode(s), whilst taking into account the cost of intervention as well as any constraints, such as outage availability for example.

## 7.4 Events Resulting from a Failure Mode

Each failure mode may result in one or more failure mode events. The events are categorised in a hierarchy of failure mode consequences, in terms of the impact of failure, and are comparable across the asset types. An example of a hierarchy of events, which is based on transformer failure modes, is shown in Table 4.

| Event |
|---|
| 01 - No Event |
| 02 - Environment Noise |
| 03 - Reduced Capability |
| 04 - Alarm |
| 05 - Unwanted Alarm + Trip |
| 06 - Transformer Trip |
| 07 - Reduced Capability + Alarm + Trip |
| 08 - Fail to Operate + Repair |
| 09 - Reduced Capability + Alarm + Loss of Voltage Control + Fail to Operate |
| 10 - Overheating (will trip on overload) |
| 11 - Cross Contamination of Oil |
| 12 - Alarm + Damaged Component (Tap Changer) No Trip |
| 13 - Alarm + Trip + Damaged Component (Tap Changer) |
| 14 - Alarm + Trip + Tx Internal Damage |
| 15 - Loss of oil into secondary containment |
| 16 - Alarm + Trip + Damage + State Requiring Replacement (Asset Replacement) |
| 17 - Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement |
| 18 - Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement+ Transformer Fire |

**Table 5**

The same failure mode may result in different events. For example, Table 5 shows the potential events for the dielectric failure of a transformer bushing.

| Asset Type | Item | Function | Failure Mode | Cause | Event |
|---|---|---|---|---|---|
| Transformer | Bushing | Carries a conductor through a partition such as a wall or tank and insulates it therefrom | Dielectric failure (oil, oil impregnated paper, resin imp paper, resin bonded paper, solid cast resin, SF6) | Water ingress/ treeing (partial discharge) | 18 - Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement+ Transformer Fire |
| | | | | | 17 - Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement |
| | | | | | 14 - Alarm + Trip + Internal Damage |
| | | | | | 05 - Unwanted Alarm + Trip |

Table 6

In all instances of this failure mode, the transformer will trip, and a component will be damaged, which will require investigation and repair. However, there is also a 50% chance of the transformer failing disruptively, i.e. that the transformer will need to be replaced rather than repaired. Table 6 shows the same failure mode events as given in Table 4, this time with return to service time. Note that these are example times and that actual return to service times may vary for individual assets depending on, for example, the nature of the failure, availability of spare parts, resourcing issues, or existing system constraints.

| Event | Example Unplanned Return to Service (days) |
|---|---|
| 01 - No Event | 0 |
| 02 – Environment Noise | 1 |
| 03 - Reduced Capability | 1 |
| 04 - Alarm | 1 |
| 05 - Unwanted Alarm + Trip | 1 |
| 06 - Transformer Trip | 1 |
| 07 - Reduced Capability + Alarm + Trip | 1 |
| 08 - Fail to Operate + Repair | 1 |
| 09 - Reduced Capability + Alarm + Loss of Voltage Control + Fail to Operate | 1 |
| 10 - Overheating (will trip on overload) | 1 |
| 11 - Cross Contamination of Oil | 1 |
| 12 - Alarm + Damaged Component (Tap Changer) No Trip | 5 |
| 13 - Alarm + Trip + Damaged Component (Tap Changer) | 30 |

| 14 - Alarm + Trip + Tx Internal Damage | 30 |
|---|---|
| 15 - loss of oil into secondary containment | 15 |
| 16 - Alarm + Trip + Damage + State Requiring Replacement (Asset Replacement) | 180 |
| 17 - Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement | 180 |
| 18 - Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement+ Transformer Fire | 180 |

**Table 7**

## 7.5 Identify and Assess Failure Mode Effects

Failure Modes and Effects Analysis (FMEA) is a structured, systematic technique for failure analysis that is used to establish an asset's likelihood of failure. It involves studying components, assemblies, and subsystems to identify failure modes, their causes, and effects. NGET uses FMEA to examine the effectiveness of its current risk management approach by considering these key elements relating to potential failure modes:

1. What are the effects and consequences of the failure mode?
2. How often might the failure mode occur?
3. How effective is the current detection method?
4. How effective are the interventions for the failure mode?

FMEA views the asset as an assembly of items, each item being the part of the asset that performs a defined function. When identifying failure modes, the items under consideration are usually sub-assemblies, but there may be discrete components. Some of the asset categories are single asset types which can be separated into an integrated set of items.

It is necessary to identify the consequences of each potential failure event to determine the risk. Some illustrative guidance is provided by section 5.2.5 of BS EN 60812, which stresses the importance of considering both local and system effects – recognising that the effects of a component failure are rarely limited to the component itself.

## 7.6 Identify & Assess Failure Mode Effects

The determination of Probability of Failure (PoF) can be especially challenging for highly reliable assets. BS EN 60812 provides useful guidance on how to develop an estimate for PoF. Section 5.2.9 of BS EN 60812 recognises that it is very important to consider the operational profile (environmental, mechanical, and/or electrical stresses applied) of each component that contributes to its probability of occurrence. This is because, in most cases, the component failure rates and consequently failure rates of the failure modes under consideration increase proportionally with the increase of applied stresses with the power law relationship or exponentially. Probability of occurrence of the failure modes for the design can be estimated from:

5. Data from the component life testing
6. Available databases of failure rates
7. Field failure data
8. Failure data for similar items or for the component class

When probability of occurrence is estimated, the FMEA must specify the period over which the estimations are valid (such as the expected service life).

Section 5.3.4 of BS EN 60812 provides further guidance on the estimation of failure rates where measured data is not available for every asset and specific operation condition (as is generally the case for transmission assets). In this case, environmental, loading and maintenance conditions different from those relating to the "reference" failure rate data are accounted for by a modifying factor. Special care needs to be exercised to ensure that the chosen modifiers are correct and applicable for the specific system and its operating conditions.

As part of the FMEA approach, an end of life curve is derived for each asset. Some of these predicted deterioration curves may be theoretical as the actual mechanism may not have occurred in practice; these are based on knowledge of asset design and specific R&D into deterioration mechanisms. NGET makes use of the following sources of data in deriving deterioration curves:

9. Evidence from inspection of failed and scrapped assets
10. Results of condition assessment tests
11. Results from continuous monitoring
12. Historical and projected environmental performance (e.g. oil loss)
13. Historical and projected unreliability
14. Defect history for that circuit breaker family.

The end of life failure curves are expressed in terms of the data points corresponding to the ages at which 2.5%, and 97.5% of failures occur. The method for determining the end of life curves is explained in sections 7.8 – 7.13.

Typically, within each lead asset group there are separate end of life curves determined for each family grouping. Assignment to family groupings is through identification of similar life-limiting factors.

## 7.7 Factors Influencing Failure Modes Probability: Differentiators & Modifiers

There may be factors that change the shape of failure mode degradation curves depending on the asset or asset family. Examples of differentiating factors may include:

1. Some families of an asset type may have a design weakness which could influence their failure mode and hence probabilities of failure
2. Location specific reasons, such as proximity to coastal areas or heavily polluted industrial areas, may also influence the probability of failure for the asset

Modifiers change the rate at which an asset progresses along a curve. There may be variations in terms of the condition and duty on assets of a particular type, so while they will have the same failure modes, and hence the same degradation curves, they may proceed along the curve at a different rate.

This introduces the concept of equivalent age. An asset can be compared to another asset which was installed at the same time which might be at a different point of progression along the curve due to specific location and/or operational reasons.

By conducting inspections, it is possible to understand where each asset lies on the curve and therefore the assets can be moved down the curve, effectively reducing their equivalent age, or vice versa, as shown in Figure 5. Assets are assessed to establish any modifying factors.



An inspection will provide information that can change the equivalent age of an asset
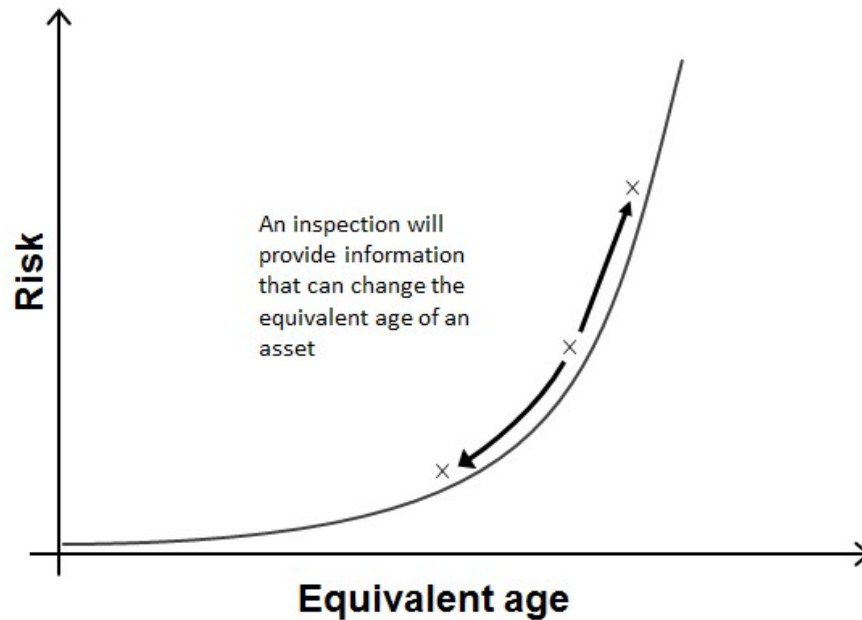
**Figure 5**

## 7.8 Mapping End of Life Modifier to Probability of Failure

The end of life probability of failure (PoF), which is the probability of end of life failure in the next year given that the asset is still surviving at the beginning of the year, is determined from the end of life (EoL) modifier. The EoL modifier is determined from the asset's current condition, duty, age, and asset family information and, through the process described below. This is converted to PoF.

A probability mapping function is required to enable mapping from an EoL modifier to a PoF. Figure 6 below illustrates distributions representing the end of life failure mode for a population of transformers.

PoF cannot be utilised at an individual asset level to infer individual asset risk, and therefore the PoF values need to be aggregated across the asset population to support the calculation of risk. Over a population of assets at a given PoF we have an expectation of how this PoF will continue to deteriorate over time, duty, or condition. This is shown by the PoF curve in red in Figure 6.



**Figure 6**

The development of a methodology that maps the EoL modifier to PoF considers the actual number of failures experienced, it should then be validated against the expected population survival curve, and it should satisfy the following requirements:
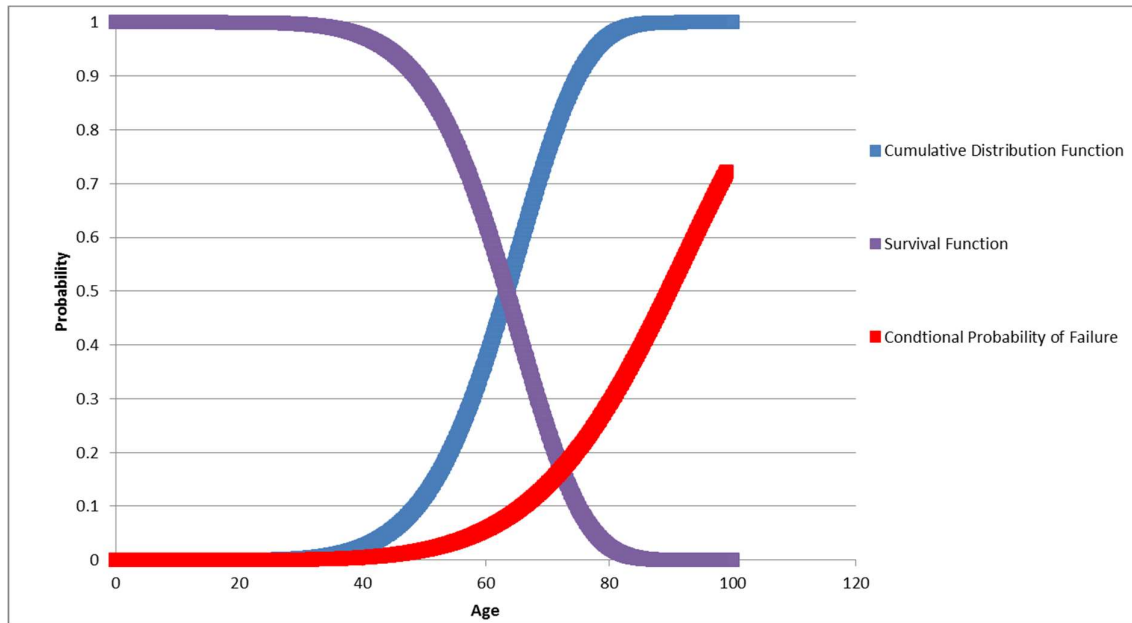
1. High scoring young assets should be replaced before low scoring old assets. The mapping function achieves this objective because high scoring assets will always reach their AAL quicker than those of low scoring assets.
2. When two assets of similar criticality have the same PoF then the older asset should be replaced first. The mapping function will assign the same PoF to both assets, so they reach their respective AAL at the same time. In practice the planner could prioritise the older asset for replacement over the younger asset without penalty.
3. When an asset is not replaced the PoF should increase. The EoL modifier score reflects the condition of the asset and will therefore increase over time. This means the PoF will also increase.
4. A comprehensive and steady replacement programme will lead to a stabilisation of the population's average PoF. The proposed methodology will satisfy this requirement as worsening PoF would be offset by replacements.
5. The PoF and resulting risks must be useful for replacement planning. The proposed methodology is validated against the expected survival function, so should be compatible with existing replacement planning strategies.
6. Outputs should match observed population data. The expected survival function for the population is already identified based on known asset deterioration profiles and NGET experience. The mapping to PoF method is validated against this expected population statistic.

The mapping function is given by the following equations.

$$Conditional\ PoF = \exp{(k * EoLmod^{\alpha})} - 1$$

$$k = ln\frac{(1 + \beta)}{EoLmod_{AALH}{}^{\alpha}}$$

Where:
EoLmod = End of Life Modifier
EoLmod$_{AALH}$ = End of Life modifier at Anticipated Age of Low Health

The parameters $\alpha$ and $\beta$ are tuned so that the deterioration profile over the population is consistent with the expected survival function for the relevant population of assets. The expected survival function is given by the FMEA earliest and latest onset of failure values, which have been determined though the transmission owner experience using all available information such as manufacturer data and understanding of asset design.

The parameter k scaling value ensures that for an EoL modifier score of EoLmod$_{AALH}$ (default value of 100) the expected PoF is obtained (given as $\beta$ in the formula below).

In the following example, the PoF mapping function is derived for a transformer, then the mapping curve parameters are systematically adjusted through a process of validation and calibration against the expected population's survival curve.

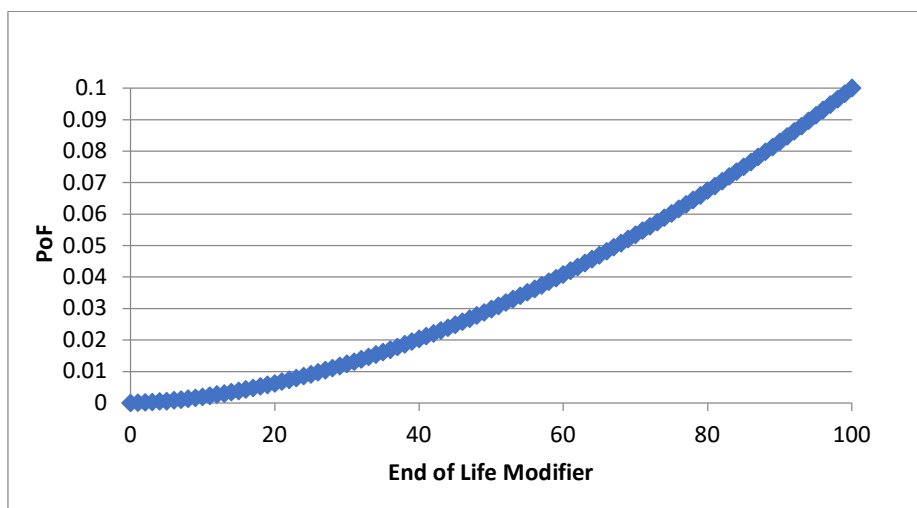The PoF mapping function is shown in the figure below for a transformer with $\alpha$=1.7 and $\beta$=10%.

A minimum PoF of 0.0001 will be applied to assets that have an actual age greater than half of their earliest onset of failure (this is named the PoF Floor).

## 7.9 Determining Alpha (α), Beta (β) and Validation

To tune the parameters, alpha (α) and beta (β), and validate the approach, the Predicted Actual Age at Failure (PAAF) for each asset needs to be determined so that a population survival curve may be determined. Using the PoF, an Equivalent Age (EA) is identified using the red curve in Figure 6 above. The PAAF calculation also needs actual Age and the age when the asset has reached a state of very poor health (Anticipated Age of Low Health, AALH).

$$PAAF = \text{Age} + (\text{AALH - EA})$$

**Equation 8**

The EoL modifier score for an individual asset puts it on a PoF curve n years away from the AALH. This n years value can be interpreted as the difference between the AALH and the equivalent age of the asset (AALH – EA). Combining with actual age gives the PAAF, as shown in Equation 9.

The PAAF can then be used to generate a survival curve that indicates the percentage of the population that is still surviving at a given age. Comparison with the expected survival curve allows the parameters alpha (α) and beta (β) to be calibrated. Figure 8 below shows an example modelled transformer survival curve based on PAAF (blue) overlaid with the expected survival curve generated from the FMEA curve (red). The modelled PoF is observed to give a good fit to the expected survival curve up to 60 years old. The trend diverges from the expected survival curve. This section of the survival curve is not as well understood, as there is little operational experience at this older age range. The linear appearance of the older section of the modelled survival curve (blue) is driven by a large population of transformers that are all around a similar age of 49 years old and have a relatively even spread of EoL modifier scores.
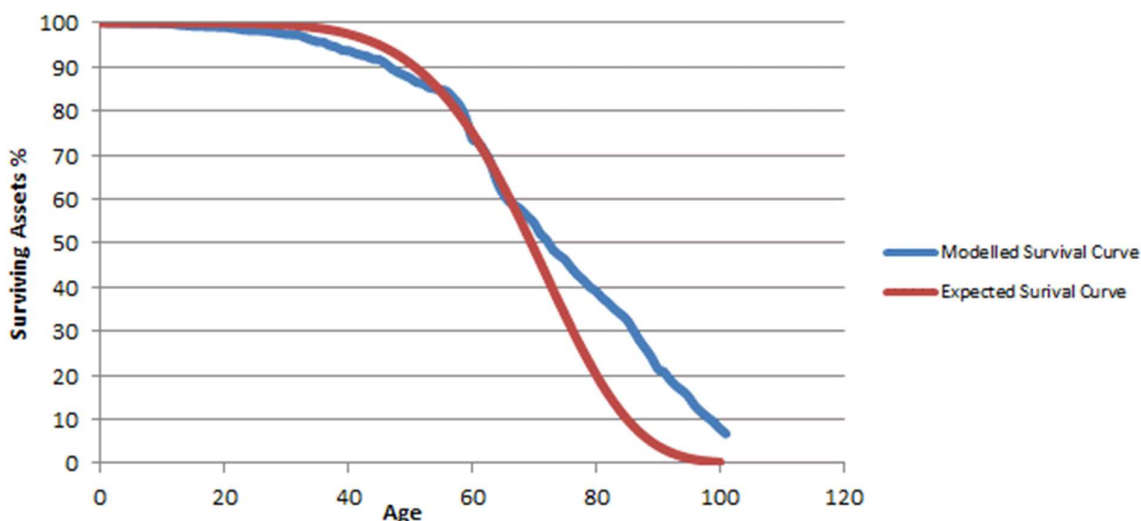


**Figure 8**

Beta ($\beta$) sets the maximum PoF which would be expected for an asset that has reached a state requiring replacement. For the purpose of implementing this methodology, β is given an assumed value of 10% (meaning 10% probability of failing in the next year) for an EoL modifier score of Score$_{AALH}$, which represents an asset in a state requiring replacement. These parameters will be flexed where this is necessary to achieve alignment with the expected number of events and expected deterioration. The Score$_{AALH}$ parameter will be set at a score representative of an asset in a state requiring replacement, which is usually a score of 100.

The total PoF across the population is obtained by summing the individual PoFs; this is then compared to the observed replacements noting that many assets are expected to be replaced before they fail. The value for $\beta$ may be tuned such that the number of replacements is similar to what is observed, but any tuning needs to be performed in conjunction with the parameter $\alpha$. These parameters primarily need to be calibrated to achieve good agreement between the PAAF survival curve with the policy survival curve, as described in the previous section, but the total PoF should also be inside an acceptable range of expected values.

The parameters alpha ($\alpha$) and beta ($\beta$) are both calibrated by considering population level statistics. In the same sense the PoF or risk is only meaningful when aggregated across the asset/EoL FM population.

## 7.10 Oil Circuit Breaker PoF mapping example

The analysis described above was repeated for Oil Circuit Breaker (OCB) EoL modifier scoring data to validate and quantify the proposed method against expectation based on NGET experience. The EoL modifier values are mapped to a PoF using a similar function to that shown in Figure 8 above, noting that the value of α and β will be specific to this OCB asset type. For the purpose of implementing this methodology a PoF value of β=10% per year is assumed for an EoL modifier score of 100. An initial value of α is selected and it is assumed that it will be adjusted to provide the best fit.

Using the same method described above for transformers the PAAF for each OCB on the network is determined. Plotting these PAAF values as a survival curve, overlaid with the expected survival curve, allows quantification of the model against expected asset deterioration, and provides a mechanism for tuning the mapping parameter α. The modelled survival curve shown in Figure 9 below has been produced with α=2.1 and β=10%.
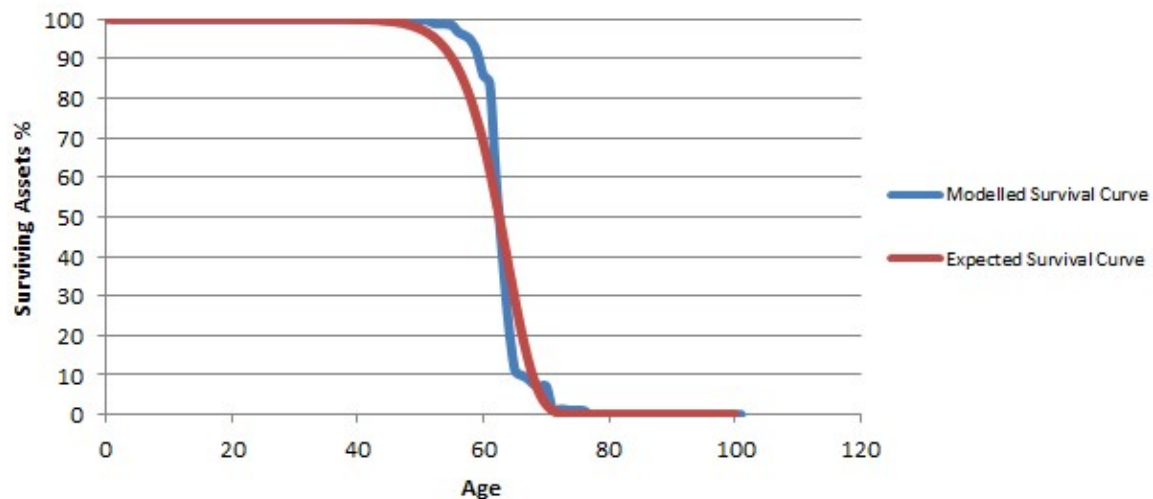


**Figure 9**

## 7.11 Calculating Probability of Failure

As described above the PoF curve is based on two data points that correspond to the ages at which specific proportions of the asset's population is expected to have failed. Using these data points we can construct a cumulative distribution function F(t). The survival function, or the cumulative probability of survival until time t, is given as: S(t) = 1-F(t). The probability of failure, which is the probability an asset fails in the next time period given that it is not in a failed state at the beginning of the time period, is then given by the following formula, where t is equivalent age in the case of end of life failure modes:

$$PoF(t) = S(t) - S(t + 1)$$

**Equation 9**

In order to calculate the end of life PoF associated with a given asset, the asset will need to be assigned an EoL modifier. This EoL modifier is derived from values such as age, duty, and condition information where it is available. In the absence of any condition information, age is used. The service experience of assets of the same design and detailed examination of decommissioned assets may also be considered when assigning an EoL modifier. Using the EoL modifier an asset's equivalent age can then be determined and mapped onto a specific point on the PoF curve.

The generalised EoL modifier (*EoLmod*) formula has the following structure for assets that have underlying issues that can be summed together:

$$EoLmod = \sum_{i=1}^{n} C_i$$

<div align="center">**Equation 10**</div>

Where
n = number of components

Or, for transformer assets that are single assets with parallel and independent failure modes, the following generalised EoL modifier formula is used:

$$EoLmod = \left(1 - \prod_{i=1}^{n}\left(1 - \frac{C_i}{C_{max}}\right)\right) * 100$$

<div align="center">**Equation 11**</div>

$C_i$ = an individual component parameter of the end of life modifier
$C_{max}$ = the maximum score that the component can be assigned

For some of the lead asset types, the generalised formula will need to be nested to derive an overall asset EoL modifier. For example, in the case of overhead lines (OHLs), the maximum of the preliminary EoL modifier and a secondary EoL modifier are taken.

The EoL modifier will range from 0 to 100, where 100 represents the worst health that an asset could be assigned. It is then necessary to convert the EoL modifier to a PoF to enable meaningful comparison across asset types.

As far as reasonably possible the scores assigned to components of the EoL modifier are set such that they are comparable e.g. are the same magnitude. This enables the EoL modifier between different assets in the same family to be treated as equivalent. The validation and testing of these scores are described in the testing section of the NARM Common Methodology; and a summary of these activities is given in Appendix B.

## 7.12 Forecasting Probability of Failure

Future PoF is estimated by following the appropriate failure curve. Depending on the type of failure mode the current position on the failure curve is identified using either age, equivalent age, or last intervention date. The forecast is determined by following along this curve, usually at the rate of one year per year. Figure 10 illustrates the PoF for an asset highlighting the PoF at an equivalent age of 80.
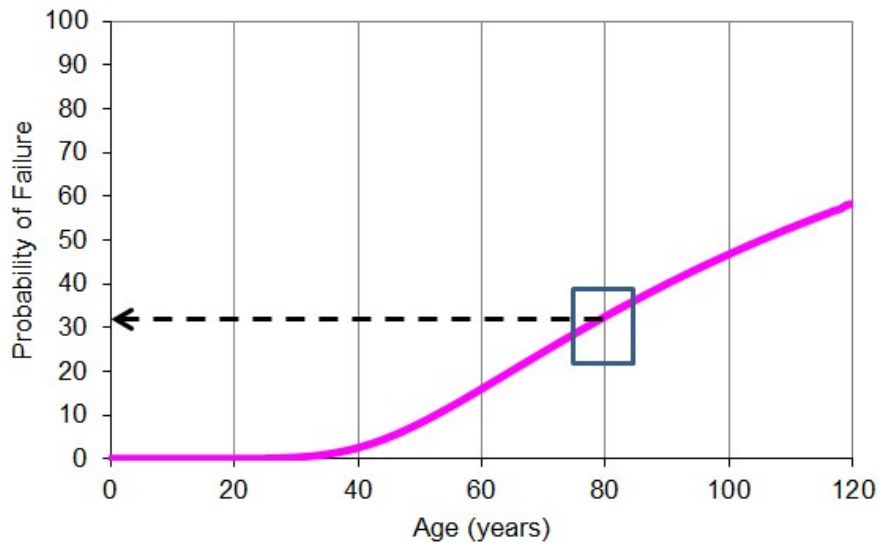


Figure 10

The forecast probability of failure in future years can then be obtained by following along the curve. For example, the forecast for Y+7 would be the value given by the above curve at the equivalent age of 87. Note that in this case it is not the real age of the asset, but an equivalent age that has been determined through the process described in the above sections.

Where appropriate and enough historical data exists, a rate multiplier can be applied, so that for each annual time step in forecast time equivalent age is increased or decreased by the rate multiplier time step. The default value of the rate multiplier time step is set as 1.0 per year. This modelling feature will allow high duty assets to be forecast more accurately.

## 7.13 Summary of the Process for Determining EoL Probability of Failure

The process illustrated below will be used to determine the PoF of each asset. This is done by translating through a probability mapping step, so that the appropriate end of life curve may be used to determine the probability of an asset having failed.
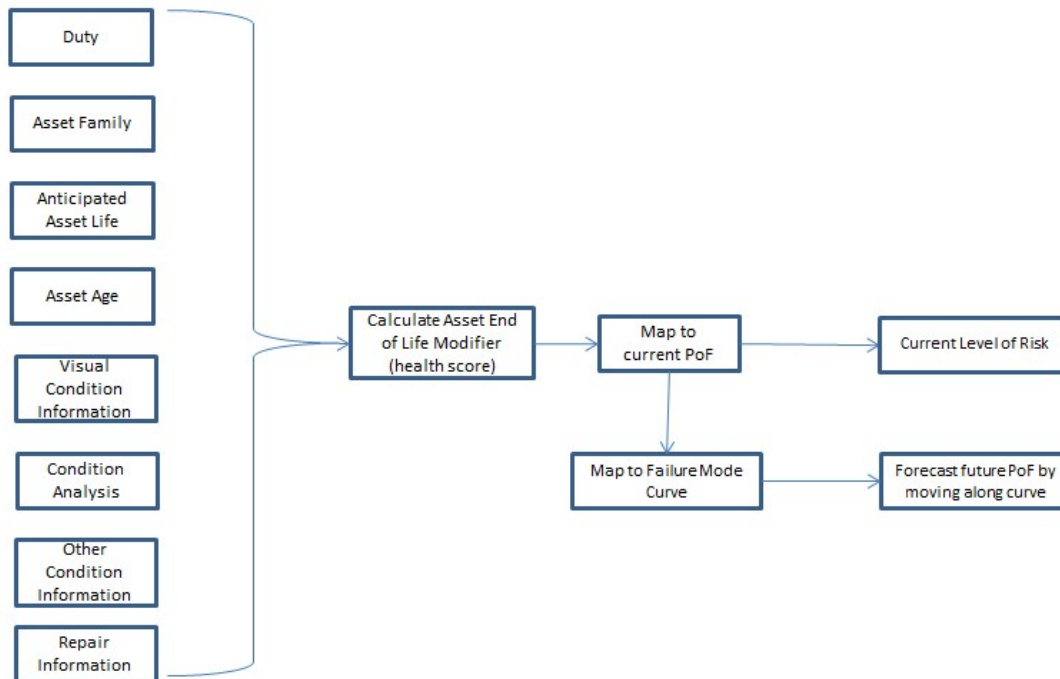


**Figure 11**

# 8 Consequences of Failure

The Consequences of Failure are evaluated in four major categories: system, safety, environmental and financial. The output is best considered a method of comparing the relative risk of different items, i. e an index.

| Consequence | Description |
|---|---|
| System | The impact on the network of the failure and any subsequent intervention required |
| Safety | Impact of direct harm to public/personnel as a result of failure mode |
| Environment | Impact of failure mode taking into account the sensitivity of the geographical area local to the asset |
| Financial | Cost of the intervention needed to address and resolve the failure |

**Table 7**

These categories reflect the impact of the various failure modes which are specific to the asset and the consequences are consistent for each class of failure mode. The impact of the various failure modes will vary depending on the type of failure. For example, for less disruptive failure modes there may be no impact from a safety perspective.

Safety and environmental consequences are specific to the asset and its physical location.

In a highly-meshed system, such as a transmission network, consideration of system effects is important. The current methodology employs a comprehensive system of consequence evaluation.

In considering the safety and environment consequences, the concept of exposure is needed. Exposure is based upon the asset's location, i.e. its proximity to a location where it has the potential to cause harm (whether to people or the environment).

Each consequence will be monetised and the price base for consequence of failure is defined in the NGET Licensee Specific Appendix Section 3 – Consequence of Failure document if it does not feature in this NARA.

NGET states which failure modes have been included in the analysis and explains why the chosen failure modes are considered appropriate for the analysis.

It is the aim of this section to provide a quantified view in the terms of monetised consequence. Note that consequence values during RIIO-T2 have been frozen at values used in the Final Determination plan in 2019.

In taking the approach detailed below it is intended that the quantification forms an approximation to how this may play out in the real world. In this case an approximation is of much greater value, due to its simplified nature and the ease of comparison and benchmark. All quantities used will be externally verifiable and benchmarked, where practicable to do so, as part of Calibration, Testing and Validation.

## 8.1 System Consequences

The System Consequences model considers the degree of redundancy associated with a given asset. A substation benefitting from a higher degree of redundancy will be considered to have lower system risks.

System consequences comprises of several factors: constraints at transmission boundaries, customer disconnections and reactive costs.

Boundary Transfer costs indicate the increase in cost to run the system with a restricted boundary capacity due to a fault/outage.

Reactive compensation consequences relate to the cost of replacing reactive compensation after a fault.

The cost of a customer disconnection takes into account the generation disconnected and replaced, the Value Of Lost Load, and the presence of vital infrastructure.

The system consequence of a failure or failure mode effect of an asset is an indication of the asset's importance in terms of its function to the transmission system as given by the disruption to that function caused by the failure. It is measured in terms of certain system related costs associated with system consequences incurred by the industry electricity sector if that asset were to experience a failure. These system costs incurred due to an asset failure can be divided into two categories, customer costs and Electricity System Operator (ESO) costs. Regardless of who initially pays these costs they are ultimately borne by electricity consumers. Customer costs are incurred as a result of the disconnection of customers supplied directly or indirectly (via a distribution network) by the transmission system. The cost for demand disconnections is expressed as the economic value that the user assigns to that lost load. In the case of generators being disconnected from the network there is a mechanism of direct compensation payments from the ESO. The second category of costs are those that the ESO incurs in undertaking corrective and preventative measures to secure the system after asset failures have occurred. These include generator constraint payments, response and reserve costs and auxiliary services costs.

Unlike the environmental, financial and safety consequences of asset failures, the existence and scale of network risk due to asset failures is dependent on the functional role that the failed asset plays in the transmission system. The transmission system is designed with a degree of resilience that seeks to ensure the impact of asset faults is contained within acceptable limits. It is the NETS SQSS that mandates a certain level of resilience that the design and operation of the transmission system must meet when faced with a range of scenarios and events. It is a license obligation of TOs that their networks comply with the NETS SQSS.

A range of negative system consequences (unacceptable overloading of primary transmission equipment, unacceptable voltage conditions or system instability) must be avoided for 'defined secured events' under certain network conditions. The required resilience is not absolute nor is it uniform across the network. The philosophy behind the NETS SQSS is that lower severity consequences are to be accepted for relatively high probability (and therefore high frequency) faults while more severe consequences are only to be accepted for lower probability events. Figure 12 represents this philosophy.

This approach is further influenced by other considerations such as the geographical location of the assets in question i.e. which TO License Area they are in, and for what timescales the network is being assessed (near term operational timescales vs. long term planning timescales). The level of resilience required also varies depending on the function of the part of the network in question. Parts of the network which connect demand, generation or make up part of the Main Interconnected Transmission System (MITS) all have distinct design requirements dependent upon their importance to the Transmission System and the total economic value of all the customers they supply.
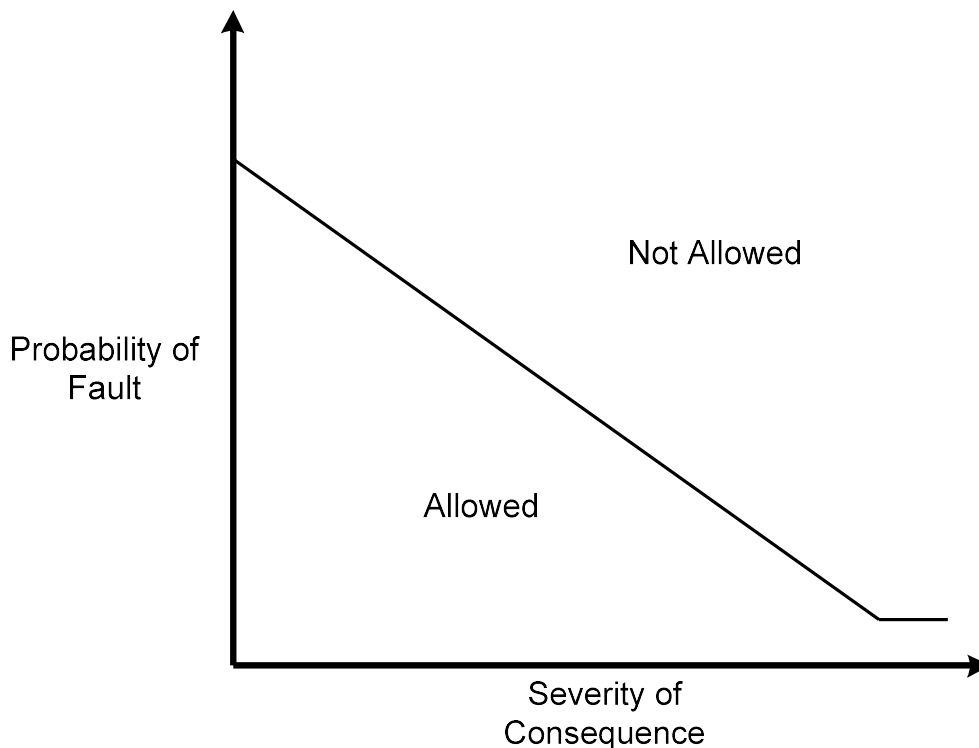
Figure 12

Events that the NETS SQSS requires a degree of resilience against are described as 'secured events'. These are events that occur with sufficient frequency that it is economic to invest in transmission infrastructure to prevent certain consequences when such events occur on the system. Secured events include faults on equipment and these events range from single transmission circuit faults (highest frequency) to circuit breaker faults (lowest frequency). When an asset fault occurs that results in the loss of only a single transmission circuit in an otherwise intact network, almost no customer losses are permitted, and all system parameters must stay within limits without the ESO taking immediate post-fault actions. While in the case of circuit breaker faults the NETS SQSS only requires that the system is planned such that customer losses are contained to the level necessary to ensure the system frequency stays within statutory limits to avoid total system collapse.

The key assumption that underpins this variation in permitted consequences of faults is that most faults are weather related and that faults caused by the condition of the asset are rare. This can be seen in that faults on overhead lines (often affected by wind and lightning) are relatively frequent events (≈20% probability per 100 km 400 kV circuit per annum) while switchgear faults are relatively less frequent (≈2% probability per 2-ended 400 kV circuit per annum). Another key assumption in the design of the SQSS is that faults are relatively short. A vast majority of circuits have a post-fault rating that is time limited to 24 hours, it is expected that faults will be resolved within this time so that this rating will not be exceeded.

Asset failures driven by asset condition do not conform to these key assumptions, they occur in assets regardless of their exposure to the elements and they can significantly exceed 24 hours in duration. The system therefore cannot be assumed to be designed to be resilient against even a single asset failure. Even if system resilience is sufficient to avoid an immediate customer or operator cost, no asset fault or failure that requires offline intervention can be said to be free from a risk cost. At the very least, the unavailability of the asset reduces system resilience to further events and therefore increases exposure to future costs.

### 8.1.1 Quantifying the System Risk Due to Asset Faults & Failures

Fundamentally, the transmission system performs three functions. It receives power from generators, transports power where it is needed and delivers it to consumers. The system risk cost of a fault or failure can be quantified by combining the following costs:

1. The economic value assigned to load not supplied to consumers including directly-connected demand customers. Commonly described as Value of Lost Load (VOLL) in units of £/MWh
2. The cost of compensating generators disconnected from the transmission system, based on the market cost of generation (£/MWh), the size of the generator (MW) and the expected duration of disconnection (hours)
3. The cost of paying for other generators to replace the power lost from disconnected generation based on the market cost of replacement generation (£/MWh) and number of megawatt hours that require replacement
4. The increased cost in transporting power across the wider transmission network. This is comprised of:
   a. Constraint payments to generators due to insufficient capacity in part of the transmission system. This comprises the costs to constrain off generation affected by the insufficient capacity and the cost to constrain on generation to replace it. If there is insufficient replacement generation capacity, costs will include demand reduction.
   b. Payments to generators to provide auxiliary services which ensure system security and quality of supply e.g. the provision of reactive power.

The applicability and size of these cost sources are dependent upon the role of the failed asset in the system. Some assets are solely for the connection of generation or demand, while others will provide multiple functions.

The methodology for calculating these potential costs is split into three parts:

1. A customer disconnection methodology, incorporating the cost of disconnecting generation, total consumer demand and vital infrastructure sites (1, 2 and 3 above)
2. A boundary transfer methodology that estimates potential generator constraint payments (4a)
3. A reactive compensation methodology that estimates the cost of procuring reactive power to replace that provided by faulted assets (4b)

Each of these methodologies will be described in turn in the following sections. All three elements share a common structure that can be expressed by Equation 13.

$$Cost\ of\ System\ Impact\ = probability\ x\ duration\ x\ size\ x\ cost\ per\ unit$$

**Equation 13**

The total cost of system impact of a failure mode of an asset will be the sum of the consequence costs that come from the three above costs.

### 8.1.2 Customer Disconnection – Customer Sites at Risk

With the exception of radial spurs, assets on the system will usually contribute towards the security of more than one substation that connects customers to the network. However, the fewer other circuits that supply a substation, the more important that asset is for the security of the site. In order to identify which sites are most at risk of disconnection because of the failure of a specific asset, the number of circuits left supplying a customer connection site after a failure of an asset, $X$, is defined;

$$X = number\ of\ parallel\ circuits\ supplying\ customer\ site(s)$$
$$- number\ of\ circuits\ tripped\ as\ a\ result\ of\ the\ Failure\ Mode\ Effect\ of\ the\ asset$$

**Equation 14**

Circuit availability statistics indicate that the importance of a circuit decreases by around two orders of magnitude for each extra parallel circuit available. Given that the uncertainty of other inputs into these calculations will be greater than 1% it is a reasonable simplification to neglect all customer sites with values of $X$ greater than the minimum value of $X$; $X_{min}=min(X)$.

Once there are four or more circuits in parallel supplying a site additional circuits do not necessarily decrease the probability of losing customers as the capacity of the remaining circuits will not be sufficient to meet the import/export of the customers at risk. In parts of the network where the number and rating of circuits connecting a substation are determined solely by the need to meet local demand, there is a significant risk that once two or three circuits have been lost cascade tripping of remaining circuits due to overloading will result.

Therefore:
- For assets on circuits containing transformers down to 132 kV or below if $X_{min} > 3$ it will be treated as $X_{min} = 3$ for the purposes of calculating the Probability of Disconnection ($P_{oc}$) and Duration ($D$).
- Otherwise for assets on circuits at 275 kV or below if $X_{min} = 4$ it will be treated as $X_{min} = 3$ for the purposes of calculating the Probability of Disconnection ($P_{oc}$) and Duration ($D$).
- Otherwise if $X_{min} > 3$ then the risk of customer disconnection will be neglected as negligible.

As there will often be multiple customer connection sites with $X=X_{min}$, to ensure that the methodology is efficient and operable a variable $Z$, is introduced which is equal to the number of customer sites with $X=X_{min}$ for a given asset. Only the largest group of customer sites that would be disconnected by the loss of a further $X_{min}$ circuits is considered explicitly while the extra risk of customer disconnection due to other combinations of circuit losses is approximated by the use of the risk multiplier coefficient $M_Z$:

$$M_Z = \frac{\sum Z + (Z-1) + (Z-2) + \dots}{Z}$$

**Equation 15**

Intuitively $M_1 = 1$, and $M_Z$ scales with increasing values of $Z$. Figure 13 illustrates an example of how $M_Z$ is calculated with three customer sites ($M_3$):
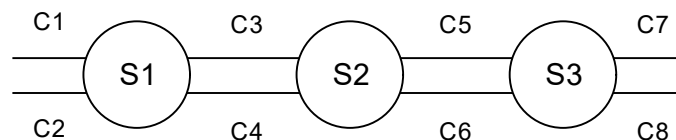


**Figure 13**

Three substations labelled S1, S2 and S3 are part of a double circuit ring with eight circuits labelled C1-C8. Each substation is immediately connected to the rest of the system by four circuits and could be disconnected from the system if these four immediate circuits were lost. However, each substation could also be disconnected by other combinations of four circuit losses also. For example S2 could be disconnected by the loss of C3, C4, C5 and C6, but also by losing C3, C4, C7 and C8 or C1, C2, C5 and C6 etc. More than one substation would be lost for these other combinations and all three substations would be lost for a loss of C1, C2, C7 and C8.

In order to calculate the total system consequence of a failure mode of an asset that is part of C1 it is assumed that the volume and cost per unit of customer connections are approximately evenly distributed among the substations (L for each substation) and that the probability (P) and duration (D) of each four circuit combination being lost is approximately equal. The relative consequence of a loss event is then determined only by the number of customers lost. So, a loss of S1 and S2 is twice the consequence of losing only S1. There is one combination of four circuit losses involving C1 that disconnected a single substation, one combination that disconnects two substations and one that disconnects all three. Therefore, the risk cost is:

$$Risk\ cost = (1 \times PDL) + (1 \times 2PDL) + (1 \times 3PDL) = 6\ PDL$$

**Equation 16**

Given the risk cost of losing all three sites at once is 3PDL so the risk cost can be expressed as a function of the risk cost of losing all three sites at once:

$$Risk\ cost = 6\ PDL = 2 \times 3PDL = 3PDLM_3$$

**Equation 17**

Therefore, $M_3$ is equal to 2.

### 8.1.3 Customer Disconnection – Probability

The probability of a generator or consumer being disconnected as a consequence of an asset failure is a function of a wide range of variables including the physical outcome of the failure, the local network topology, asset composition of circuits, asset loading, physical proximity of assets, protection configuration and operation options for restoration. The probability of consequence is calculated as a function of five probabilities, shown in Table 8.

| Probability | Symbol | Value | Determination of Value |
|---|---|---|---|
| Coincident outage | $P_o$ | $0.056*X_{min}$ | TO statistics on planned unavailability of circuits |
| Damage to another circuit | $P_d$ | Varies by asset class and failure mode. Typical range of 0 to 0.014. | TO historical experience of explosive/incendiary failures of failure mode |
| Maloperation of another circuit | $P_m$ | 0.01 | TO statistics on protection maloperation |
| Coincident fault to another circuit | $P_f$ | $0.014*X_{min}$ | TO fault statistics |
| Overloading of remaining circuit | $P_l$ | If MWD>1200 then 0.09 Otherwise, Zero. | TO specific network design |

**Table 8**

The probabilities $P_o$, $P_d$, $P_m$, $P_f$ and $P_l$ are determined separately by each TO according to their own historical experience and network properties.

The probabilities in Table 8 can be combined to create a probability tree for each value of $X_{min}$ between 0 and 3. Below are the resulting equations for $P_{oc}$, the probability of disconnection.

$$\text{For } X_{min} = 0, P_{oc} = 1$$

**Equation 18**

$$\text{For } X_{min} = 1, P_{oc} = P_d + N_d P_o + N_o N_d P_m + N_o N_d N_m P_f$$

**Equation 19**

$$\text{For } X_{min} = 2, P_{oc} = P_d^2 + 2P_d N_d P_o + 2P_d N_d N_o P_m + 2P_d N_d N_o N_m P_f + N_d^2 P_o P_m + N_d^2 P_o N_m P_f + N_d^2 N_o P_m P_f + N_d^2 N_o N_m P_f^2$$

**Equation 20**

$$\text{For } X_{min} = 3, P_{oc} = P_d^2 P_o + P_d^2 N_o P_m + P_d^2 N_o N_m P_f + P_d^2 N_o N_m N_f P_l + 2P_d N_d P_o P_m + 2P_d N_d P_o N_m P_f + 2P_d N_d P_o N_m N_f P_l + 2P_d N_d N_o P_m P_f + 2P_d N_d N_o P_m N_f P_l + 2P_d N_d N_o N_m P_f^2 + 4P_d N_d N_o N_m P_f N_f P_l + N_d^2 P_o P_m P_f + N_d^2 P_o P_m N_f P_l + N_d^2 P_o N_m P_f^2 + 2N_d^2 P_o N_m P_f N_f P_l + N_d^2 N_o P_m P_f^2 + 2N_d^2 N_o P_m P_f N_f P_l + N_d^2 N_o N_m P_f^3 + 3N_d^2 N_o N_m P_f^2 N_f P_l$$

**Equation 21**

Where $N_o$, $N_d$, $N_m$, $N_f$ and $N_l$ are the probabilities of no outage, no damage, no maloperation, no coincident faults and no overloading respectively.

The derivation method of the above probability equations can be followed in Figures 14 & 15, the probability tree diagram for the most complex of the four cases, $X_{min} = 3$.

Initial pre-failure network state

Asset Experience Failure Mode

3 circuits remaining

Asset Failure damages asset on two parallel circuits ($P_d^2$)

1 circuit remaining

Probability of parallel outage ($P_o$)

0 circuits remaining ($P_c^2 P_o$)

Probability of no parallel outage ($N_o$)

1 circuit remaining

0 circuits remaining ($P_d^2 N_o P_m$)

Probability of Maloperation ($P_m$)

Probability of no Maloperation ($N_m$)

1 circuit remaining

0 circuits remaining ($P_d^2 N_o N_m P_f$)

Probability of unrelated fault ($P_f$)

Probability of no unrelated fault ($N_f$)

1 circuit remaining

0 circuits remaining ($P_d^2 N_o N_m N_f P_l$)

Probability of overloading circuit ($P_l$)

Asset Failure damages asset on one parallel circuit ($2PdN_d$)

Asset Failure damages no assets on parallel circuits ($N_d^2$)

2 circuits remaining

Probability of parallel outage ($P_o$)

1 circuit remaining

Probability of Maloperation ($P_m$)

0 circuits remaining ($2P_d N_d P_o P_m$)

Probability of no parallel outage ($N_o$)

Probability of no Maloperation ($N_m$)

1 circuit remaining

Probability of unrelated fault ($P_f$)

0 circuits remaining ($2P_d N_d P_o N_m P_f$)

Probability of no unrelated fault ($N_f$)

1 circuit remaining

Probability of overloading circuit ($P_l$)

0 circuits remaining ($2P_d N_d P_o N_m N_f P_l$)

2 circuits remaining

Probability of Maloperation ($P_m$)

1 circuit remaining

Probability of unrelated fault ($P_f$)

0 circuits remaining ($2P_d N_d N_o P_m P_f$)

Probability of no Maloperation ($N_m$)

Probability of no unrelated fault ($N_f$)

1 circuit remaining

Probability of overloading circuit ($P_l$)

0 circuits remaining ($2P_d N_d N_o P_m N_f P_l$)

2 circuits remaining

Probability of two unrelated faults ($P_f^2$)

0 circuits remaining ($2P_d N_f N_o N_m P_f^2$)

Probability of no second unrelated fault ($2P_f N_f$)

Probability of overloading circuit ($P_l$)

1 circuit remaining

0 circuits remaining ($4P_d N_d N_o N_m P_f N_f P_l$)

Continued Below

**Figure 14**

Continued

3 circuits remaining

Probability of parallel outage ($P_o$)

2 circuits remaining

Probability of Maloperation ($P_m$)

1 circuit remaining

Probability of unrelated fault ($P_f$)

0 circuits remaining ($N_d^2 P_o P_m P_f$)

Probability of no parallel outage ($N_o$)

Probability of no maloperation ($N_m$)

Probability of no unrelated fault ($N_f$)

1 circuit remaining

Probability of overloading circuit ($P_l$)

0 circuits remaining ($N_d^2 P_o P_m N_f P_l$)

2 circuits remaining

Probability of two unrelated faults ($P_f^2$)

0 circuits remaining ($N_d^2 P_o N_m P_f^2$)

Probability of no second unrelated fault ($2P_f N_f$)

1 circuit remaining

Probability of overloading circuit ($P_l$)

0 circuits remaining ($2N_d^2 P_o N_m P_f N_f P_l$)

3 circuits remaining

Probability of Maloperation ($P_m$)

2 circuits remaining

Probability of two unrelated faults ($P_f^2$)

0 circuits remaining ($N_d^2 N_o P_m P_f^2$)

Probability of no maloperation ($N_m$)

Probability of no second unrelated fault ($2P_f N_f$)

1 circuit remaining

Probability of overloading circuit ($P_l$)

0 circuits remaining ($2N_d^2 N_o P_m P_f N_f P_l$)

3 circuits remaining

Probability of three unrelated faults ($P_f^2$)

0 circuits remaining ($N_d^2 N_o N_m P_f^3$)

Probability of two unrelated faults ($3P_f P_f N_f$)

1 circuit remaining

Probability of overloading circuit ($P_l$)
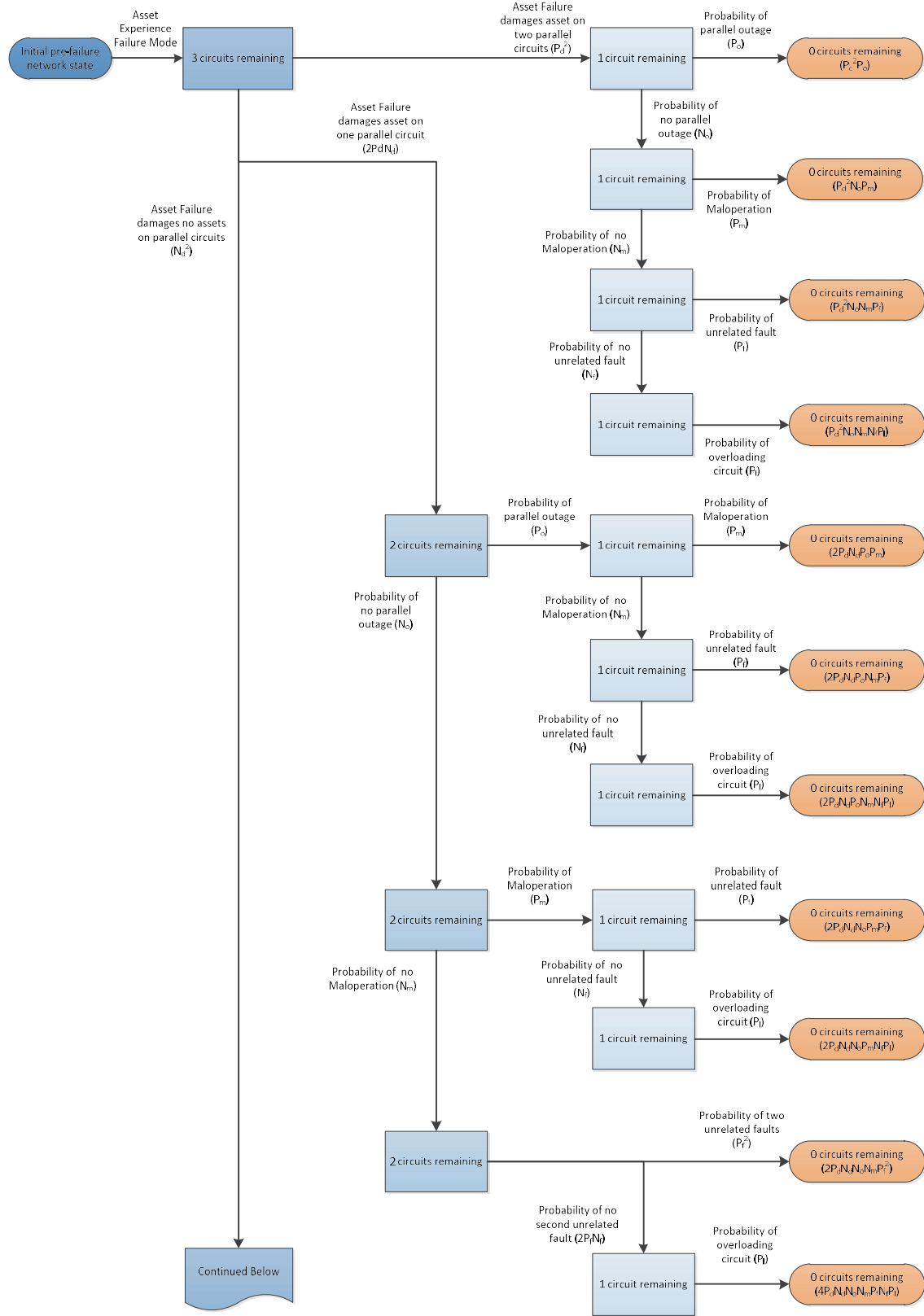
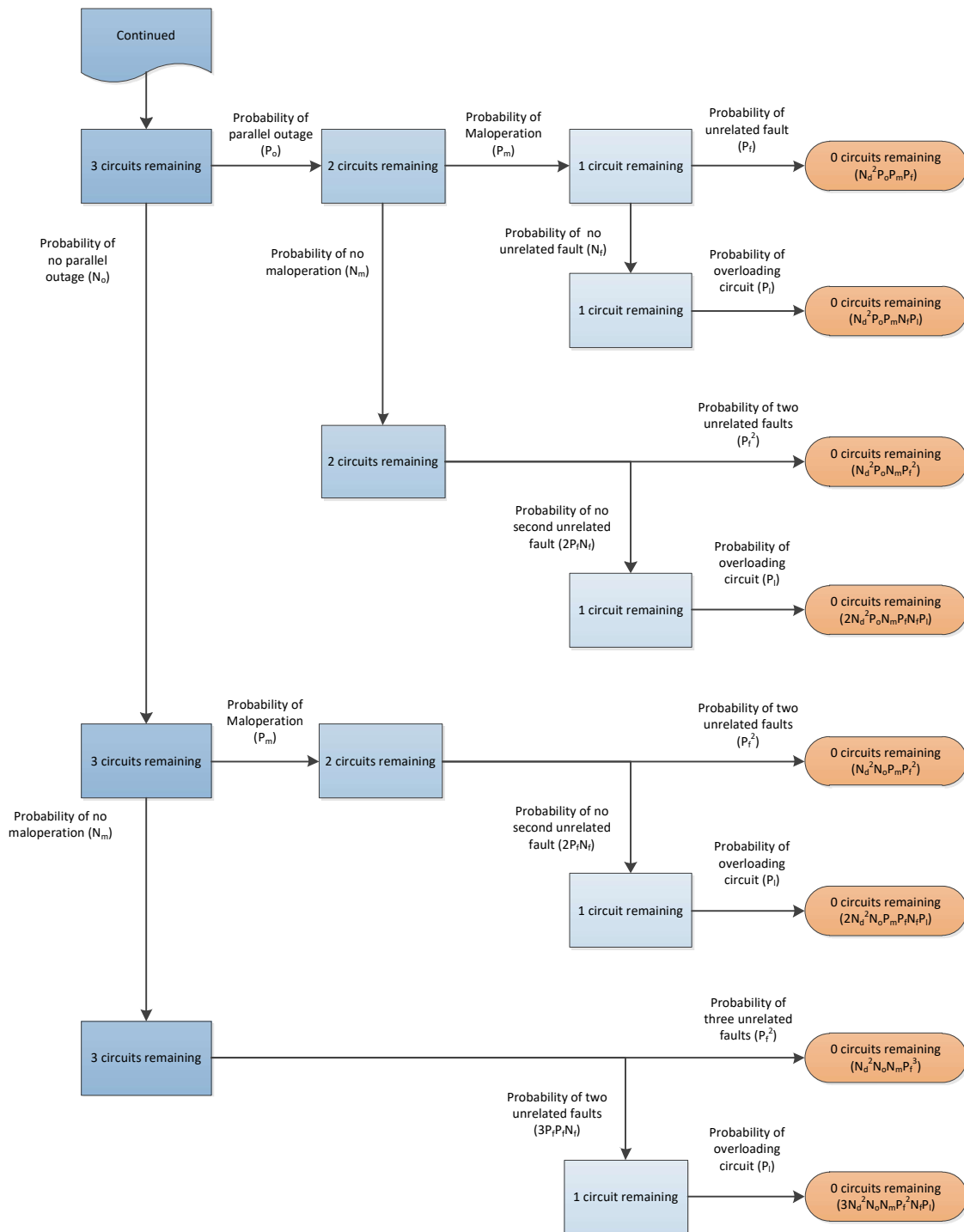0 circuits remaining ($3N_d^2 N_o N_m P_f^2 N_f P_l$)

**Figure 15**

### 8.1.4 Customer Disconnection – Duration

A similar approach is taken with the expected duration of such a disconnection event. This is dictated by the failure mode of the asset in question, and both operational and asset interventions available to restore supply to the customers. In order to calculate the duration of disconnection, six separate durations are introduced in Table 9.

| Duration | Symbol | Value (h) | Determination of Value |
|---|---|---|---|
| Duration of failure mode unavailability | $D_{fm}$ | Varies by failure mode effect and asset type with a range of 0 to 4,320 | TO experience of failure durations |
| Outage restoration time | $D_o$ | 0.5 | TO statistics on planned unavailability of circuits |
| Circuit damage restoration time | $D_d$ | 0.5 | TO historical experience of explosive/incendiary failures of failure mode |
| Protection mal-operation restoration time | $D_m$ | 0.173 | TO statistics on protection maloperation |
| Unrelated fault restoration time | $D_f$ | 0.5 | TO fault statistics |
| Circuit overload restoration time | $D_l$ | 0.165 | TO historical experience of overload trips |

**Table 9**

The durations $D_{fm}$, $D_o$, $D_d$, $D_m$ and $D_f$ are determined separately by each TO according to their own methodology outlined in TO specific appendices. The duration of customer loss is calculated by weighting the probabilities of the event combinations outlined in the formulae for $P_{oc}$ and multiplying by the shortest of the above durations that apply to that event combination. For example, if a failure mode with $X_{min}$ = 2 and disconnection is due to a combination of the failure mode, a parallel outage and protection mal-operation then the minimum of $D_{fm}$, $D_o$ and $D_m$ is weighted with the other minimum durations of other disconnection combinations. Below are the equations for $D$ for different values of $X_{min}$.

$$\text{For } X_{min} = 0,\ D = D_{fm}$$

**Equation 22**

$$\text{For } X_{min} = 1,\ D=[min(D_{fm}, D_d)P_d + min(D_f, D_o)N_dP_o + min(D_{fm}, D_m)N_oN_dP_m + min(D_{fm},D_f)N_oN_dN_mP_f\ /\ P_{oc}$$

**Equation 23**

$$\text{For } X_{min} = 2,\ D = [min(D_{fm},D_d)P_d^2 + min(D_{fm}, D_d, D_o)2P_dN_dP_o + min(D_{fm},D_d,D_m)2P_dN_dN_oP_m +$$
$$min(D_{fm},D_d,D_f)2P_dN_dN_oN_mP_f + min(D_{fm},D_o,D_m)N_d^2P_oP_m + min(D_{fm},D_o,D_f)N_d^2P_oN_mP_f + min(D_{fm},D_m,D_f)N_d^2N_oP_mP_f +$$
$$min(D_{fm},D_f)N_d^2N_oN_mP_f^2]\ /\ P_{oc}$$

**Equation 24**

$$\text{For } X_{min} = 3,\ D = [min(D_{fm},D_d,D_o)P_d^2P_o + min(D_{fm},D_d,D_m)P_d^2N_oP_m + min(D_{fm},D_d,D_f)P_d^2N_oN_mP_f +$$
$$min(D_{fm},D_d,D_l)P_d^2N_oN_mN_fP_l + min(D_{fm},D_d,D_o,D_m)2P_dN_dP_oP_m + min(D_{fm},D_d,D_o,D_f)2P_dN_dP_oN_mP_f +$$
$$min(D_{fm},D_d,D_o,D_l)2P_dN_dP_oN_mN_fP_l + min(D_{fm},D_d,D_m,D_f)2P_dN_dN_oP_mP_f + min(D_{fm},D_d,D_m,D_l)2P_dN_dN_oP_mN_fP_l +$$
$$min(D_{fm},D_d,D_f)2P_dN_dN_oN_mP_f^2 + min(D_{fm},D_d,D_f,D_l)4P_dN_dN_oN_mP_fN_fP_l + min(D_{fm},D_o,D_m,D_f)N_d^2P_oP_mP_f +$$
$$min(D_{fm},D_o,D_m,D_l)N_d^2P_oP_mN_fP_l + min(D_{fm},D_o,D_f)N_d^2P_oN_mP_f^2 + min(D_{fm},D_o,D_f,D_l)2N_d^2P_oN_mP_fN_fP_l +$$
$$min(D_{fm},D_m,D_f)N_d^2N_oP_mP_f^2 + min(D_{fm},D_m,D_f,D_l)2N_d^2N_oP_mP_fN_fP_l + min(D_{fm},D_f)N_d^2N_oN_mP_f^3 +$$
$$min(D_{fm},D_f,D_l)3N_d^2N_oN_mP_f^2N_fP_l ]/\ P_{oc}$$

**Equation 25**

### 8.1.5 Customer Disconnection – Size and Unit Cost

Once the largest group of customer sites with $X = X_{min}$ for a given failure mode of an asset has been identified the size of consequence of disconnection of this group must be fully quantified. The weighted quantity of generation disconnected, $MW_W$ is given by:

$$MW_W = \sum \varphi MW_{GTEC}$$

<div align="center">

**Equation 26**

</div>

Where $MW_{GTEC}$ is the Transmission Entry Capacity (TEC) of each disconnected generator and $\varphi$ is the design variation weighting factor. This factor equals 1 for generators who are connected with standard SQSS levels of security. Its value for generators with lower than standard levels of security will be determined by each TO. TEC is used without any reference to load factor as this is how generator disconnection compensation is calculated as laid out in the Connection and Use of System Code (CUSC). Secondly the annual average true demand of customers disconnected, $MW_D$, is calculated by summing the peak demand and the embedded generation contribution during peak of all sites at risk. Both the peak demand and contribution of embedded generation is taken directly from DNO week 24 data submissions. The final inputs are the number of vital infrastructure sites of three different types supplied by sites at risk as shown in Table 10. These are demand sites of particular importance in terms of economic or public safety impact. There is no additional quantification of the risk of disconnection of customers or consumers for which the disconnection risks are considered High Impact Low Probability (HILP) events. The risk is treated on a per MW basis like any other consumer or customer.

The lists of sites that belong to the categories outlined in Table 10 are deemed sensitive and thus are not included here. The costs of disconnection per site, per hour were calculated by collecting as much publicly available information as possible on the costs of historic disconnection events of comparable infrastructure sites across the developed world. These costs per hour or per event were converted into current prices through exchange rate and price indexation conversion. An average for each category was then taken.

| Vital Infrastructure Category | Symbol and Cost | | |
| --- | --- | --- | --- |
| | Number of Sites | Cost per site per hour (£/hr) | Cost per site per disconnection event (£) |
| Transport Hubs | $S_T$ | $V_T = 1,860,000$ | - |
| Economic Key Point | $S_E$ | $V_E = 1,440,000$ | - |
| Particularly sensitive COMAH sites | $S_C$ | - | $V_C = 16,970,000$ |

<div align="center">

**Table 10**

</div>

The final component of the risk cost, the per unit cost, is separately defined for the three above quantities of customer loss. *VOLL* is expressed in £/MWh, set at the same RPI indexed value as used in in RIIO-T2 final determinations. VOLL is set at a fixed value used in the Final Determinations for RIIO-T2 plans, calculated in 2019, of £20,000/MWh.

The cost of disconnection of generation is in two parts, firstly the generation compensation payment cost, $G_C$, in £/MWh varies with outage duration is based upon the CUSC methodology and uses cost information from the ESO.

For D ≤ 1.5h, $G_c = MW_W D C_{SBP}$

**Equation 27**

For 1.5 h < D ≤ 24h, $G_c = MW_W(1.5C_{SBP} + \{D - 1.5\}C_{SMP})$

**Equation 28**

For D > 24h, $G_c = MW_W(1.5C_{SBP} + 22.5C_{SMP} + \{D - 24\}C_{TNUoS})$

**Equation 29**

Where $C_{SBP}$ is the annual average system buy price in £MWh$^{-1}$, $C_{SMP}$ is the annual average system marginal price in £MWh$^{-1}$. $C_{SBP}$, and $C_{SMP}$ are set for RIIO-T2 at a fixed value used in the Final Determinations for RIIO-T2 plans, calculated in 2019, of £47.63/MWh, and £36.21/MWh respectively. $C_{TNUoS}$ is the average Transmission Network Use of System (TNUoS) refund cost per MW per hour. $C_{TNUoS}$ is calculated by divided the annual TNUoS charge for all generators by the total of TEC of all generators and again by 8760.

Secondly, the cost of generation replacement, $G_{R*}$, again dependent on D is defined as below.

For D ≤ 2h, $G_R = DC_{SMP}(0.42MW_W - 0.62MW_D)$

**Equation 30**

For D > 2h, $G_R = 2C_{SMP}(0.42MW_W - 0.62MW_D)$

**Equation 31**

For $G_R$ ≥ 0, $G_{R*}$ = $G_R$

**Equation 32**

For $G_R$ < 0, $G_{R*}$ = 0

**Equation 33**

This cost reflects the expense of the ESO constraining on generation to replace that lost by the disconnection of generation. The equation multiplies the duration of the disconnection and the annual average price to constrain on plant by the mismatch between the expected mismatch between generation and demand disconnected by the event. This mismatch is calculated by first taking the total TEC of generation connected to the customer sites in the group at risk, $MW_W$, and multiplying it by the system wide average generation load factor 0.42 (calculated by dividing the total energy generated in a year in MWh across the whole system by 8760 and then by the total TEC of all generation on the system). Secondly the peak adjusted demand, $MW_D$, of all customer sites in the group is multiplied by the average demand factor 0.62 (calculated by dividing the total annual transmission demand in MWh by 8760 and dividing again by the winter peak demand in MW). The difference between these two numbers is the mismatch, multiplied by the System Marginal Price in £MWh$^{-1}$ and the duration up to a maximum of 2 hours. After 2 hours it would be expected that the market would have self-corrected for the generation mismatch.

The vital infrastructure site disconnection cost, V, is the numbers of different types of vital infrastructure sites multiplied by the cost per site and in the case of transport and economic key point sites multiplied by D.

$$V = D(V_T S_T + V_E S_E) + V_C S_C)$$

**Equation 34**

With all elements of the equation defined, the customer disconnection risk cost, $R_{customer}$, of a given asset failure mode of any asset can be defined by Equation 35.

$$R_{customer} = P_{oc}[G_C + G_R + 0.62DMW_D VOLL + V]M_z$$

**Equation 35**

A vast majority of lead assets will return a non-zero value for customer disconnection risk, the exceptions being shunt reactors and circuits which connect nodes with more than four circuits. These assets will have material risks for one of the next two elements of system consequence.

### 8.1.6 Boundary Transfer

This methodology estimates the cost impact of having to pay generation constraint payments in order to restrict flows across a system boundary. Unlike the customer disconnection methodology, there is not a discrete disconnection event that either occurs or doesn't (within a given probability) but instead there is a year-round average cost per hour at which the boundary must be constrained, which implicitly includes the probability of a constraint existing. The constraint cost per hour is dependent upon the number of circuits unavailable by the asset failure, Y. In the vast majority of cases this will be 1, but tower failures would usually result in two circuits being lost until the asset can be restored. Additionally, the extra constraint cost that would result from unrelated unavailability on another circuit on the same boundary must be considered.

The derivation of average constraint costs will be based on flow and price information provided by the ESO on an annual basis. The ESO will run simulations of a full year of operation with each boundary in with intact, N-1 depletion, N-2 depletion and N-3 depletion capabilities resulting in four annual costs of operation for the boundary, $B_Y$, which is then calculated as follows:

$$B_1 = \frac{[(annual\ n-1\ cost) - (annual\ intact\ cost)]}{8760}$$

**Equation 36**

$$B_2 = \frac{[(annual\ n-2\ cost) - (annual\ intact\ cost)]}{8760}$$

**Equation 37**

$$B_3 = \frac{[(annual\ n-3\ cost) - (annual\ intact\ cost)]}{8760}$$

**Equation 38**

While a failure mode that renders Y circuits unavailable will incur costs at least the $B_Y$ level, on average a proportion of the duration of the failure mode will be spent with Y+1 circuits unavailable, defined as $P_{Y+1}$. The proportion used is derived from historic fault and outage probabilities and durations. The probability of sustained boundary depletion beyond Y+1 circuits is assumed to be negligible.

These costs are multiplied by the duration of the unavailability of the asset until it is returned to service, $D_{fm}$, dependent upon historic precedent for the asset type and failure mode in question.

With the variables defined the methodology for determining the boundary transfer risk cost, $R_{boundary}$, of an asset failure mode of any asset can be described by Equation 39.

$$R_{boundary} = D_{fm}[B_Y(1 - P_{Y+1}) + B_{Y+1}P_{Y+1}]$$

**Equation 39**

This methodology will return non-zero risk costs for all assets that belong to or affect circuits critical to the capability of one or more system boundaries with significant constraint implications.

Equation 39 can be illustrated with the example of B6, the boundary between the SPT and National Grid Electricity Transmission (NGET) areas. There are currently four circuits that make up this boundary. If a failure of an asset which makes up part of one of these circuits occurs then this circuit will be unavailable until the failure has been rectified, Y = 1 for this failure. The boundary will be at N-1 depletion until the failure is rectified and on average will spend some proportion, $P_{Y+1}$, of the duration of failure at a N-2 depletion level due to unrelated prior outages or other unrelated faults. The weighted average boundary constraint cost per hour is calculated by first multiplying $B_1$ by (1- $P_{Y+1}$), the proportion of time that the boundary is at N-1 depletion. Then B2 is multiplied by the proportion of time that the boundary will spend at N-2 depletion, $P_{Y+1}$. These two products are added together. This average boundary cost per hour is then simply multiplied by the average time taken to restore the circuits to service by repairing the failed asset, $D_{fm}$. This gives us the total expected boundary constraint for the failure mode of the asset.

### 8.1.7 Reactive Compensation

The third element of the system consequence methodology calculates the cost impact of having reactive compensation unavailable due to a fault or failure of any asset that would render the reactive compensation unusable. This could include circuit breakers, transformers, and cables as well as the compensation itself. The purpose of reactive compensation is to produce or consume reactive power to aid control of system voltage. When compensation equipment is unavailable this reactive power control is either procured from generators instead or elements of the transmission system are de-energised, reducing system resilience.

As a simplification the cost impact of a fault or failure can be quantified as the volume of reactive power not supplied multiplied by the cost per MVArh the ESO must pay to buy the same service from generators. Therefore, we have Equation 40 to calculate the reactive compensation system risk cost (RRC) of an asset Failure Mode:

$$R_{RC} = R_F D_{fm} Q C_{MVArh}$$

**Equation 40**

Where

$R_F$ is the requirement factor of the compensation equipment made unavailable or the proportion of the year that the compensation in question is required on a scale of 0 to 1.
$D_{fm}$ is the duration of unavailability due to the asset failure mode.
$Q$ is the capacity of the asset in MVAr.
$C_{MVArh}$ is the average cost of procuring of MVAr from generation sources.

CMVArh will be calculated by taking an annual sum of all costs of generators to absorb MVArs including balancing mechanism actions to bring plant into service and constrain others as well as the cost of providing the reactive absorption itself. This sum is divided by the total number of MVArhs that were absorbed by generators over the year.

### 8.1.8 High Impact, Low Probability (HILP) Assets

High impact, low probability events are mostly outside the scope of NARM. The network is designed and built to withstand certain levels of faults and failures, as defined in the Security and Quality of Supply Standard (SQSS). A HILP event arising from a single NARM asset event is not considered a credible scenario.

A High Impact Low Probability (HILP) asset will have an element of 'HILP' risk associated with it that is not the same as Asset Risk. An example of a HILP asset may be an asset associated with transmission network black start capabilities or an asset associated with connection of a nuclear site to the transmission network.

The HILP risk will be associated with an event that NGET wish to avoid (e.g. the tripping of a nuclear power station) but one that is also difficult to quantify in risk terms. The probability of such an event is very low; and the consequences are extremely high. Therefore, multiplying the two elements together can result in a reasonable value of risk. Thus, Monetised Risk is not a particularly effective tool for exploring HILP risk.

Application of the NARM Common methodology, described in this NARA and associated supporting documentation, may result in HILP assets ending up lower down in a prioritised list of assets for intervention, based on their Asset Risk.

In instances like this, NGET may choose to intervene on a HILP asset in preference to an asset with an equal or higher Asset Risk and will justify each decision. Note there is no mechanism within RIIO-T2 to account for such activity.

## 8.2 Safety Consequence

Within NGET, our safety performance is paramount. This section details how safety consequence is calculated in monetised terms.

When assets fail, they have the potential to cause harm to both the general public and personnel who work on or near to the assets. In circumstances where this happens, there is a cost to society. The aim of this part of the methodology is therefore to capture the safety risks that deteriorating assets present to individuals who are exposed to their effects and the associated cost. Note that NGET also has statutory safety responsibilities, that are not included in the safety consequence, as these tasks must be carried out.

In general, the safety risk for an individual asset can be expressed as shown below:

$$Safety\ Risk = \sum_i \left( P\left(C_{saf,i}\right) \times C_{saf,i}\right)$$

**Equation 41**

Where:

$P\left(C_{saf,i}\right)$ = Probability of failure mode effect i occurring as a result of a failure event
$C_{saf,i}$ = Safety-related costs associated with asset failure resulting in failure mode effect i

For an individual asset the general expression for $C_{saf}$ is as follows:

$$C_{saf} = Probability\ of\ Injury \ \times Cost\ of\ Injury \ \times Safety\ Exposure$$

**Equation 42**

Where:

Probability of Injury = the likelihood that an individual is injured when exposed to the effects of an asset failure
Cost of Injury = the cost associated with an individual sustaining an injury
Safety Exposure = modifier to reflect the number of people who are exposed to the effects of an asset failure

Individuals exposed to asset failures can potentially sustain injuries of varying severity and the likelihood of these injuries occurring will depend on the asset under consideration, the type of failure that occurs and the effects associated with that failure. Moreover, the cost associated with different types of injury will vary. Taking into account these variables the 'Safety Cost' can be more formally expressed as shown below:

$$C_{saf,i} = \sum_j Probability\ of\ Injury_{j,i} \ \times Cost\ of\ injury_j \ \times Safety\ Exposure$$

**Equation 43**

Where:
i = failure mode effect
j = injury type

## 8.2.1 Failure Mode Effect & Probability of Failure Mode Effect

The failure mode effect represents the possible effects that NGET considers as a result of failure and the probability of failure mode effect represents its likelihood of occurrence. The effects that are considered by NGET and the calculation of their likelihood are described below.

### 8.2.2 Injury Type & Probability of Injury

Individuals can sustain varying degrees of injury as a result of an asset failure. NGET proposes to categorise the severity of injury into the following types, using HSE definitions[3]:

1. Slight – Injury involving minor cuts and bruises with a quick and complete recovery
2. Serious - Slight to moderate pain for 2-7 days. Thereafter some pain/discomfort for several weeks. Some restrictions to work and/or leisure activities for several weeks/months. After 3-4 months return to normal health with no permanent disability.
3. Permanent Incapacitating Injury - Moderate to severe pain for 1-4 weeks. Thereafter some pain gradually reducing but may recur when taking part in some activities. Some permanent restrictions to leisure and possibly some work activities.
4. Fatality

The 'Probability of Injury' represents the likelihood that an individual is injured when exposed to the effects of an asset failure. Probabilities will be assigned to each 'Injury Type' considered. The probability assigned to each category will vary depending on the failure mode that occurs and the effects that occur as a result of the failure mode effect materialising. For less disruptive failures there may be no impact from a safety perspective and the probability of injury will be zero. In addition, because it is assumed that the probability of injury applies to an individual, the sum of probabilities across all injury type categories for a failure effect is less than or equal to unity (i.e. an individual's injuries can only be classified under a single category of injury). The probability of injury types, per failure mode effect, are shown in table 11.

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[3] https://www.hse.gov.uk/managing/theory/alarpcheck.htm

| Asset Type | Event | P(slight) | P(serious) | P(permanent incapacitating injury) | P(fatality) |
|---|---|---|---|---|---|
| Tx | 01- No Event | 0 | 0 | 0 | 0 |
| Tx | 02- Environment Noise | 0 | 0 | 0 | 0 |
| Tx | 03- Reduced Capability | 0 | 0 | 0 | 0 |
| Tx | 04- Alarm | 0 | 0 | 0 | 0 |
| Tx | 05- Unwanted Alarm + Trip | 0 | 0 | 0 | 0 |
| Tx | 06- Transformer Trip | 0 | 0 | 0 | 0 |
| Tx | 07- Reduced Capability + Alarm + Trip | 0 | 0 | 0 | 0 |
| Tx | 08- Fail to Operate + Repair | 0 | 0 | 0 | 0 |
| Tx | 09- Reduced Capability + Alarm + Loss of Voltage Control + Fail to Operate | 0 | 0 | 0 | 0 |
| Tx | 10- Overheating (will trip on overload) | 0 | 0 | 0 | 0 |
| Tx | 11- Cross Contamination of Oil | 0 | 0 | 0 | 0 |
| Tx | 12- Alarm + Damaged Component (Tap Changer) No Trip | 0 | 0 | 0 | 0 |
| Tx | 13- Alarm + Trip + Damaged Component (Tap Changer) | 0 | 0 | 0 | 0 |
| Tx | 14- Alarm + Trip + Tx Internal Damage | 0 | 0 | 0 | 0 |
| Tx | 15- loss of oil into secondary containment | 0 | 0 | 0 | 0 |
| Tx | 16- Alarm + Trip + Damage + State Requiring Replacement (Asset Replacement) | 0 | 0 | 0 | 0 |
| Tx | 17- Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement | 0 | 0.551 | 0.331 | 0.118 |
| Tx | 18- Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement+ Transformer Fire | 0 | 0.551 | 0.331 | 0.118 |
| CB | 01- No Event | 0 | 0 | 0 | 0 |
| CB | 02- Reduced Function | 0 | 0 | 0 | 0 |
| CB | 03- Operate Outside Design Parameters | 0 | 0 | 0 | 0 |
| CB | 04- System effect | 0 | 0 | 0 | 0 |
| CB | 05- Alarm and lock out (different levels for trip and close) | 0 | 0 | 0 | 0 |
| CB | 06- Unwanted operation | 0 | 0 | 0 | 0 |
| CB | 07- Damage to other control circuit | 0 | 0 | 0 | 0 |
| CB | 08- Replace insulator | 1 | 0 | 0 | 0 |
| CB | 09- Fail to Operate + Repair | 1 | 0 | 0 | 0 |
| CB | 10- Disconnector Damage | 1 | 0 | 0 | 0 |
| CB | 11- Fail to Operate + CB damage + Repair | 1 | 0 | 0 | 0 |
| CB | 12- Disconnector Failure (End of Life) | 0 | 0 | 0 | 0 |
| CB | 13- CB failure (end of life) | 0 | 0 | 0 | 0 |
| CB | 14- Alarm + Trip + Damage + Disruptive Disconnector Failure (Replace) | 0.9985 | 0.0015 | 0 | 0 |

| | | | | | |
|---|---|---|---|---|---|
| CB | 15- overheating high resistance contacts RIDDOR report | 0.9985 | 0.0015 | 0 | 0 |
| CB | 16- Alarm + Trip + Damage + Disruptive CB Failure (Replace) | 0 | 0.551 | 0.331 | 0.118 |
| CB | 17- Alarm + Trip + Disruptive Failure + Collateral Damage + Replacement | 0 | 0.551 | 0.331 | 0.118 |
| OHL | 01- No Event | 0 | 0 | 0 | 0 |
| OHL | 02- Overheating - reduced function | 0 | 0 | 0 | 0 |
| OHL | 03- Noise | 0 | 0 | 0 | 0 |
| OHL | 04- Flashover | 0 | 0 | 0 | 0 |
| OHL | 05- Trip | 0 | 0 | 0 | 0 |
| OHL | 06- Component Wear - scheduled repair | 0 | 0 | 0 | 0 |
| OHL | 07- Conductor Damage and Repair | 0 | 0 | 0 | 0 |
| OHL | 08- Fittings wear - reduced function | 0 | 0 | 0 | 0 |
| OHL | 09- Insulator Fails - continues in service | 0 | 0 | 0 | 0 |
| OHL | 10- Tower defect - repair | 0 | 0.551 | 0.331 | 0.118 |
| OHL | 11- Fittings Failure (State Requiring Refurbishment) | 0 | 0 | 0 | 0 |
| OHL | 12- OHL Failure (State Requiring Replacement) | 0 | 0 | 0 | 0 |
| OHL | 13- Potential Harm | 0 | 0.551 | 0.331 | 0.118 |
| OHL | 14- Conductor Fall and Trip | 0 | 0.551 | 0.331 | 0.118 |
| OHL | 15- Conductor Fall, Conductor Remains Live | 0 | 0.551 | 0.331 | 0.118 |
| OHL | 16- Conductor, Fittings, Steelwork Fall and Trip | 0 | 0.551 | 0.331 | 0.118 |
| Cables | 01- No Event | 0 | 0 | 0 | 0 |
| Cables | 02- False Oil Pressure Reading | 0 | 0 | 0 | 0 |
| Cables | 03- Reduction in circuit rating | 0 | 0 | 0 | 0 |
| Cables | 04- Loss of pressure (OFC) | 0 | 0 | 0 | 0 |
| Cables | 05- Trip | 1 | 0 | 0 | 0 |
| Cables | 06- Component Damage (CSE) | 0 | 0 | 0 | 0 |
| Cables | 07- Damage to cable | 1 | 0 | 0 | 0 |
| Cables | 08- Trip + Dielectric Defect (XLPE) | 1 | 0 | 0 | 0 |
| Cables | 09- Trip + Dielectric Defect (OFC) | 1 | 0 | 0 | 0 |
| Cables | 10-Loss of Pressure + Loss of oil to environment (OFC) | 0 | 0 | 0 | 0 |
| Cables | 11- Uncontrolled flashover | 0 | 0.551 | 0.331 | 0.118 |
| Cables | 12- Accessory Refurbishment | 0 | 0 | 0 | 0 |
| Cables | 13- Injury or harm | 0 | 0.551 | 0.331 | 0.118 |
| Cables | 14- Thermal runaway | 0 | 0.551 | 0.331 | 0.118 |
| Cables | 15- Cable Failure (State Requiring Replacement) | 0 | 0 | 0 | 0 |
| Cables | 16- Alarm + Trip + Disruptive Failure | 0 | 0.551 | 0.331 | 0.118 |
| Cables | 17- Alarm + Trip + Disruptive Failure with Fire | 0 | 0.551 | 0.331 | 0.118 |

Table 11

### 8.2.3 Cost of Injury

Fixed costs will be assigned to the different injury types recognised by the HSE as per their website[4], which are inflated to a cost-base of 2016/17 in line with RPI[5], these are shown in table 12 below.

Whilst the appraisal values reflect a broad range of cost categories, for simplicity of presentation the appraisal values can be divided into two main component costs:

- Human costs - representing a monetary estimate of the loss of quality of life, and loss of life in the case of fatal injuries
- Financial costs, which are the sum of the following:
  - Productivity costs including:
    - net lost income, taking into account of loss of output and earnings due to absence from work, and offsetting transfers from one party to another, e.g. benefits payments are a cost to Government, but an equal and opposite offsetting benefit to individuals
    - production costs, such as cost of recruitment and work reorganisation
  - The cost of Employer's Liability Compulsory Insurance, less compensation payouts to individuals
  - Health and rehabilitation costs, such as NHS costs
  - Administrative and legal costs, such as costs of administering benefits claims

| Injury Type | HSE Definitions | HSE 2016/17 Inflated Values |
|---|---|---|
| FATALITY | | £2,005,200 |
| INJURY | | |
| Permanently incapacitating injury | Moderate to severe pain for 1-4 weeks. Thereafter some pain gradually reducing but may recur when taking part in some activities. Some permanent restrictions to leisure and possibly some work activities. | £310,800 |
| Serious | Slight to moderate pain for 2-7 days. Thereafter some pain/discomfort for several weeks. Some restrictions to work and/or leisure activities for several weeks/months. After 3-4 months return to normal health with no permanent disability. | £30,750 |
| Slight | Injury involving minor cuts and bruises with a quick and complete recovery. | £450 |

**Table 12**

NGET calculates the 'Cost of Injury' as follows:

$$Cost\ of\ Injury_j = \sum Total\ Cost\ (Rounded) \times Disproportion\ Factor$$

**Equation 44**

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[4] https://www.hse.gov.uk/managing/theory/alarpcheck.htm
[5] https://www.ons.gov.uk/economy/inflationandpriceindices/timeseries/chaw/mm23

The 'Total Cost (Rounded)' is reflected by the HSE values, as per their website, which are inflated to a cost-base of 2016/17 in line with RPI.

A disproportion factor recognises the high risk nature of the Transmission Industry. Such disproportion factors are described by the HSE guidance when identifying reasonably practicable costs of mitigation. This value is not mandated by the HSE, but they state that they believe that "the greater the risk, the more should be spent in reducing it, and the greater the bias should be on the side of safety"[6].

In the NARA, the Disproportion Factor is set to the maximum value recommended by the HSE of **10**, which reflects the importance NGET places on safety risk.

### 8.2.4 Safety Exposure

Safety consequences are specific to individual assets and their physical location. Some assets will expose a greater number of people to their failure effects than others depending on the levels of activity near to the asset. The 'Probability of Injury' only considers whether an individual will be injured assuming they are exposed to the effects of an asset failure and does not consider whether it is likely that one or more individuals will be within the vicinity of an asset when it fails. In order to take into account the likely number of people exposed to the effects of an asset failure (e.g. where an event impacts multiple people at the same time) a 'Safety Exposure' modifier is incorporated into the 'Safety Cost of Failure Mode Effects' calculation.

Under the Electricity Safety Quality and Continuity Regulations 2002 (ESQCR), risk assessments must be carried out on NGET assets to assess the risk of interference, vandalism, or unauthorised access to the asset by the public.

The overall safety exposure value is built from the following components:

- Location:
  - Proximity to areas that may affect its likelihood of trespass or interference
  - Personnel activity in the vicinity of the asset

| Location/Exposure Risk Rating | |
|---|---|
| Low | Limited personnel access. No likely public access |
| Medium | Regular personnel/public activity in the vicinity of the asset |
| High | High levels of personnel/public activity in the vicinity of the asset |
| Very High | Constant personnel/public activity in the vicinity of the asset |

**Table 13**

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[6] https://www.hse.gov.uk/managing/theory/alarpcheck

The values used for each safety exposure score (Low-Very High), are included below. The following factors have been taken into consideration:

- Number of hours per annum of an individual staff member being in the vicinity of an asset on the system, due to:
    - Routine activities
    - Maintenance activities
    - Replacement activities
    - Switching activities
    - Meetings in substation buildings
    - Office base at substation buildings

- Number of hours per annum to an individual member of the public being in the vicinity of an asset, due to:
    - Domestic activity
    - Industrial activity
    - Rights-of-way
    - Agricultural activity
    - Educational activity
    - Commercial activity
    - Retail activity

The safety exposure factor takes an average value of hours per annum for an individual to be within the vicinity of an NGET asset. This presents an average safety exposure value for each of the four categories, reflective of a ratio of the number of hours per annum for an individual to be within the vicinity of an NGET asset compared to the number of hours in a year. The average value is taken due to the number of NGET sites, such that the sites included in each exposure category can vary significantly, and the category for 'Very High' exposure will contain the anomaly sites with extreme cases of public and staff exposure, significantly higher than the remaining sites within that category. The average value is used as the most appropriate representation of the exposure levels for the majority of sites within each relevant exposure category.

The following table outlines the calculated exposure factors.

| Exposure Category | Criteria | Exposure Value |
|---|---|---|
| Very High | • Large substation with office accommodation, typically large double busbar substation with several supergrid transformers.<br>• Office accommodation for National Grid employees, with conferencing facilities within close proximity to HV equipment. This is in addition to routine inspections, maintenance activities and switching operations.<br>• Urban environment or adjacent to a power station.<br>• Substation in location where there is constant third party or public activity. | 13.88 |
| High | • Large substation with office accommodation, typically large double busbar substation or large mesh substation with multiple supergrid transformers.<br>• Office accommodation for personnel with or without conferencing facilities is not within close proximity to HV equipment but access to these office buildings can take personnel within the vicinity of the HV equipment. This is in addition to routine inspections, maintenance activities, and switching operations.<br>• Rural environment.<br>• Public access within 50m of equipment or building within 50m of equipment. | 6.00 |
| Medium | • Large substation, typically double busbar, or mesh substations with at least three mesh corners.<br>• Any permanent site office accommodation is not located within the HV compound.<br>• Activities at site are confined to routine inspections, maintenance activities, and switching operations.<br>• Rural environment.<br>• Public access within 100m of equipment or building within 100m of equipment | 0.07 |
| Low | • Small substation, typically a teed connection or single switch mesh.<br>• Activities at site confined to routine inspections, maintenance activities, and switching activities.<br>• Rural environment.<br>• No general access to substation. | 0.06 |

**Table 14**

These values are used to calculate the safety risk for an individual asset. An example now follows for a transformer on a site with Medium exposure. The values given are dummy values for demonstration purposes.

| Event | P(slight) | P(serious) | P(permanent incapaci-tating injury) | P(fatality) | £(slight) | £(serious) | £(permanent incapaci-tating injury) | £(fatality) | DF | Exp | FMEA Safety CoF | PoE | Asset Safety Risk |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 01- No Event | 0 | 0 | 0 | 0 | £450.00 | £30,750.00 | £320,800.00 | £2,005,200.00 | 10 | 0.07 | 0 | 0.72 | |
| 02- Environment Noise | 0 | 0 | 0 | 0 | £450.00 | £30,750.00 | £320,800.00 | £2,005,200.00 | 10 | 0.07 | 0 | 0.17 | |
| 03- Reduced Capability | 0 | 0 | 0 | 0 | £450.00 | £30,750.00 | £320,800.00 | £2,005,200.00 | 10 | 0.07 | 0 | 0.34 | |
| 04- Alarm | 0 | 0 | 0 | 0 | £450.00 | £30,750.00 | £320,800.00 | £2,005,200.00 | 10 | 0.07 | 0 | 0.95 | |
| 05- Unwanted Alarm + Trip | 0 | 0 | 0 | 0 | £450.00 | £30,750.00 | £320,800.00 | £2,005,200.00 | 10 | 0.07 | 0 | 0.31 | |
| 06- Transformer Trip | 0 | 0 | 0 | 0 | £450.00 | £30,750.00 | £320,800.00 | £2,005,200.00 | 10 | 0.07 | 0 | 0.10 | |
| 07- Reduced Capability + Alarm + Trip | 0 | 0 | 0 | 0 | £450.00 | £30,750.00 | £320,800.00 | £2,005,200.00 | 10 | 0.07 | 0 | 0.10 | |
| 08- Fail to Operate + Repair | 0 | 0 | 0 | 0 | £450.00 | £30,750.00 | £320,800.00 | £2,005,200.00 | 10 | 0.07 | 0 | 0.74 | |
| 09- Reduced Capability + Alarm + Loss of Voltage Control + Fail to Operate | 0 | 0 | 0 | 0 | £450.00 | £30,750.00 | £320,800.00 | £2,005,200.00 | 10 | 0.07 | 0 | 0.80 | |
| 10- Overheating (will trip on overload) | 0 | 0 | 0 | 0 | £450.00 | £30,750.00 | £320,800.00 | £2,005,200.00 | 10 | 0.07 | 0 | 0.25 | |
| 11- Cross Contamination of Oil | 0 | 0 | 0 | 0 | £450.00 | £30,750.00 | £320,800.00 | £2,005,200.00 | 10 | 0.07 | 0 | 0.78 | £45,619.16 |
| 12- Alarm + Damaged Component (Tap Changer) No Trip | 0 | 0 | 0 | 0 | £450.00 | £30,750.00 | £320,800.00 | £2,005,200.00 | 10 | 0.07 | 0 | 0.25 | |
| 13- Alarm + Trip + Damaged Component (Tap Changer) | 0 | 0 | 0 | 0 | £450.00 | £30,750.00 | £320,800.00 | £2,005,200.00 | 10 | 0.07 | 0 | 0.02 | |
| 14- Alarm + Trip + Tx Internal Damage | 0 | 0 | 0 | 0 | £450.00 | £30,750.00 | £320,800.00 | £2,005,200.00 | 10 | 0.07 | 0 | 0.96 | |
| 15- loss of oil into secondary containment | 0 | 0 | 0 | 0 | £450.00 | £30,750.00 | £320,800.00 | £2,005,200.00 | 10 | 0.07 | 0 | 0.37 | |
| 16- Alarm + Trip + Damage + State Requiring Replacement (Asset Replacement) | 0 | 0 | 0 | 0 | £450.00 | £30,750.00 | £320,800.00 | £2,005,200.00 | 10 | 0.07 | 0 | 0.21 | |
| 17- Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement | 0 | 0.551 | 0.331 | 0.118 | £450.00 | £30,750.00 | £320,800.00 | £2,005,200.00 | 10 | 0.07 | £251,819.16 | 0.02 | |
| 18- Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement+ Transformer Fire | 0 | 0.551 | 0.331 | 0.118 | £450.00 | £30,750.00 | £320,800.00 | £2,005,200.00 | 10 | 0.07 | £251,819.16 | 0.17 | |

## 8.3 Environmental Consequence

Commitments to Net Zero by 2050 are front and centre to both the national agenda and National Grid's stated objectives. Environmental consequence encompasses both local impacts as well as $CO_2e$ emissions. The environmental consequence is calculated by quantifying four categories as a result of a failure mode effect: oil, SF6, waste produced and fire.

When assets fail they have the potential to impact on the geographical area local to the asset. The aim of this part of the methodology is to capture the different environmental effects that deteriorating assets present and the associated costs. In general the total environmental risk for an asset can be expressed as shown below:

$$Environmental\ Risk = \sum_i \left( P\left(C_{env,i}\right) \times C_{env,i} \right)$$

**Equation 45**

Where:
$P\left(C_{env,i}\right)$ = Probability of failure mode effect i occurring as a result of a failure event
$C_{env,i}$ = Environmental-related costs associated with asset failure resulting in failure mode effect i

For an individual asset the general expression for $C_{env}$ is:

$$C_{env} = Cost\ of\ Environmental\ Impact\ \times Impact\ Volume \times Environmental\ Exposure$$

**Equation 46**

Where:
Cost of Environmental Impact – the costs arising from a failure event that has an impact on the environment
Impact Volume – the average volume of environmental impact per failure mode effect
Environmental Exposure – modifier to reflect the sensitivity of the environment exposed to the effects of an asset failure event

In reality, the environment exposed to asset failures can potentially sustain varying severities of environmental impacts, and the likelihoods of these environmental impacts occurring is dependent on the asset under consideration, the type of failure that occurs and the effects associated with the failure. Consequently, the costs associated with different types of environmental impacts will vary. Taking into account these variables the 'Environmental Cost of Failure Mode Effect' can be formally expressed as shown below:

$$C_{env,i} = \sum_j Cost\ of\ Environmental\ Impact_j \times Impact\ Volume_j \times Environmental\ Exposure$$

**Equation 47**

Where:

| | | |
|---|---|---|
| **i** | = | Failure Mode Effect |
| **j** | = | Environmental Impact Type |

### 8.3.1 Failure Mode Effect & Probability of Failure Mode Effect

The failure mode effects represent the possible effects that NGET considers as a result of a failure event and the probability of failure mode effect represents its likelihood of occurrence. The environmental effects that are considered by NGET and the calculation of their likelihoods are described below.

The probability assigned to each environmental impact type, see section 8.3.2, will vary depending on the failure mode that occurs and the effects that result from the failure mode event materialising. For less disruptive failures there may be no impact on the environment.

The failure mode effect represents the possible effects that TOs consider because of failure and the probability of failure mode effect represents its likelihood of occurrence.

### 8.3.2 Cost of Environmental Impact

The Cost of Environmental Impact is calculated as an average cost where there is loss of oil, loss of $SF_6$, fire and/or generation of waste for each failure mode effect. The following costs are applied to each environmental impact component:

Environmental Impact Costs (£ 2016/17):

- Environmental cost per litre of oil = £39.33/litre
- Environmental cost per kg of $SF_6$ lost = £308.99/kg
  This is derived from:
    - Traded carbon price = £13.45/tonne
    - Cost of $SF_6$ loss compared with cost of carbon = 22,800kg(CO2)/kg
- Environmental cost of fire = £5,618 per fire
- Environmental cost per tonne of waste = £168.54/tonne

The sources for the above costs are given in the following table. They have been adjusted for RPI to achieve a cost-base of 2016/17.[7] As with other consequence values, these parameters are fixed for the duration of RIIO-T2 for reporting purposes.

| Fixed value | Source (£ 2012/13) |
|---|---|
| Environmental cost per litre oil (£/litre) | The value used in the DNO CNAIM, page 81: https://www.ofgem.gov.uk/system/files/docs/2017/05/dno_common_network_asset_indices_methodology_v1.1.pdf<br><br>and in Ofgem's RIIO-ED1 Cost Benefit Analysis template (used for the RIIO-ED1 submissions) |
| Traded carbon price (£/t) | https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/671194/Updated_short-term_traded_carbon_values_for_appraisal_purposes.pdf Table 1, central value estimated as of 2021 |
| Conversion factor for cost of SF6 loss c/w cost of carbon (kg CO2e/kg) | https://www.gov.uk/guidance/calculate-the-carbon-dioxide-equivalent-quantity-of-an-f-gas |
| Environmental Cost of Fire | The value used in the DNO CNAIM, page 81: https://www.ofgem.gov.uk/system/files/docs/2017/05/dno_common_network_asset_indices_methodology_v1.1.pdf |
| Environmental Cost per Tonne Waste | The value used in the DNO CNAIM, page 81: https://www.ofgem.gov.uk/system/files/docs/2017/05/dno_common_network_asset_indices_methodology_v1.1.pdf |

**Table 16**

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[7] https://www.ons.gov.uk/economy/inflationandpriceindices/timeseries/chaw/mm23

An example of the environmental risk of a cable of medium exposure now follows. Please note the figures are for demonstration purposes only.

| Event | Oil Lost (l) | SF6 Lost (kg) | Waste (dry weight, tonne) | Number of Fires | Environmental Consequence for Failure Mode Effect | PoE | Exposure Score | Environmental Risk |
|---|---|---|---|---|---|---|---|---|
| CBL01- No Event | 0 | 0 | 0 | 0 | £ - | 0.05 | | |
| CBL02- Reduced Rating of Cable | 0 | 0 | 0 | 0 | £ - | 0.05 | | |
| CBL03 - Minor repair + no oil lost/oil recovered | 0 | 0 | 0 | 0 | £ - | 0.05 | | |
| CBL04 - Minor repair + oil loss to environment | 176.6 | 0 | 0 | 0 | £ 6,946.81 | 0.05 | | |
| CBL05 - Minor repair | 0 | 0 | 0.01 | 0 | £ 1.69 | 0.05 | | |
| CBL06 - Cooling system refurbishment | 0 | 0 | 0.3 | 0 | £ 50.56 | 0.05 | | |
| CBL07 - Cable System refurbishment | 0 | 0 | 0.3 | 0 | £ 50.56 | 0.05 | | |
| CBL08- Trip | 0 | 0 | 0 | 0 | £ - | 0.05 | | |
| CBL09 - Trip + cable system damage XLPE | 0 | 0 | 0 | 0.5 | £ 2,809.00 | 0.05 | | |
| CBL10 - Trip + cable system damage OFC + no oil lost/oil recovered | 0 | 0 | 0 | 0.5 | £ 2,809.00 | 0.05 | 2 | £5,321.47 |
| CBL11 - Trip + cable system damage OFC + oil lost to environment | 185 | 0 | 0.25 | 0.5 | £ 10,126.45 | 0.05 | | |
| CBL12 - Trip + cable system damage + fire | 123.3 | 0 | 0.3 | 1 | £ 10,518.77 | 0.05 | | |
| CBL13 - Trip + cable system damage + injury/harm | 0 | 0 | 0 | 0 | £ - | 0.05 | | |
| CBL14 - Trip + cable system damage + injury/harm + fire | 185 | 0 | 0 | 1 | £ 12,893.31 | 0.05 | | |
| CBL15 - Injury/harm (no cable system damage) | 0 | 0 | 0 | 0 | £ - | 0.05 | | |
| CBL16 - Full cable system failure (cable system replacement - planned) | 0 | 0 | 17.5 | 0 | £ 2,942.47 | 0.05 | | |
| CBL17 - Full cable system replacement (cable system replacement - unplanned) | 0 | 0 | 17.5 | 0.2 | £ 4,066.07 | 0.05 | | |

**Table 17**

### 8.3.3 Environmental Exposure

Due to the distributed nature of networks, it is important that exposure is taken into account. Environmental consequences are specific to individual asset size and their physical location. Some assets pose a greater risk to the environment than others. In order to account for this an 'Environmental Exposure' modifier is incorporated into the 'Environmental Consequence of Failure Mode Effect' calculation.

### 8.3.4 Location Factor

Location factor allows for an adjustment to be made based on an assessment of the environmental sensitivity of the site on which an asset is located. The specific concerns will vary by asset type but include proximity to watercourses and other environmentally sensitive areas. The factor also recognises any mitigation associated with the asset. This factor is derived by combining separate factors relating to proximity to a watercourse or Site of Special Scientific Interest (SSSI).

| Environmental Exposure Category | Criteria | Exposure Score |
|---|---|---|
| Low | • Asset located in controlled environment | 1 |
| Medium | • Asset may be located in controlled, environment which may be located within 100m of environmentally sensitive area. <br> • Distributed asset located greater than 100m from sensitive environment | 2 |
| High | • Distributed asset, all, or part of which, is located within 100m of Source Protection Zone, abstraction, or surface water course or SSSI | 1000 |

**Table 18**

## 8.4 Financial Consequence

The financial cost of failure is driven by the cost of investigation, repair, and replacement of an asset.

When assets fail they have the potential to impact on the geographical area local to the asset. The aim of this part of the methodology

The Financial Consequence of Failure is derived from an assessment of the typical replacement and repair costs incurred by the failure of the asset in each of its applicable Failure Modes and is multiplied by the probability of each Failure Mode effect.

$$Financial\ Risk\ (k) = \sum_i \left( P\big(C_{fin,i}\big) \times C_{fin,i} \right)$$

**Equation 48**

Where:
$P\big(C_{fin,i}\big)$ = Probability that event i occurs
$C_{fin,i}$ = Financial consequence of the event's effect

The FMEA process identifies asset items and the failure events associated with them. Each failure event may result in one or more Failure Mode effects and each effect has consequences. The probability of the events resulting from each Failure Mode is determined through the FMEA process.

The Financial Consequence for each effect is derived from the average cost to repair or replace the asset (or assets if the failure results in a disruptive failure where adjacent assets are damaged) based on existing repair and replacement data. The costs presented are the labour and repair costs as well as OMGS (Other Materials, Goods and Services), which are necessary to carry out the repair or replacement of the failed asset. Additional costs, associated with the failure but not incurred in carrying out the repair or replacement, such as environmental clean-up or formal incident investigation costs (undertaken following catastrophic failures, for example), are not considered as part of the Financial Consequence.

To illustrate, the following Failure Mode effects result from events associated with transformers. It is the event which has the consequence; hence the costings are derived for each event. In order to validate the costing, the Failure Modes which cause the event are also presented.

| Event | Connected with Failure Mode/cause | Activities used to derive average cost (this table will show actual costs in the Licensee Specific Appendix following CTV) |
|---|---|---|
| 01- No Event | | |
| 02- Environment Noise | Noise caused by anti vibration pads failing or faulty fans | Labour costs and component costs plus OMGS |
| 03- Reduced Capability | Downratings due to pumps/fans failure or overheating caused by carbon build up on tap changers | Labour costs to investigate and repair. Component costs + OMGS |
| 04- Alarm | Overheating alarm | Labour costs for alarm investigation |
| 05- Unwanted Alarm + Trip | Unintentional operation of Buchholz or WTI | Labour costs for trip investigation |
| 06- Transformer Trip | high res contacts on diverters | Labour costs for trip investigation |
| 07- Reduced Capability + Alarm + Trip | Overheating due to WTI failure. Contactor/control relay failure Pump failure  Fan failure Incorrect valve position  Blockages (sludging)  cooler blockage external OR loss of oil due to tank corrosion | Labour costs to investigate and repair. Component costs + OMGS |
| 08- Fail to Operate + Repair | Buchholz or WTI fail to trip or alarm, overheating on tap changers, | Labour costs to investigate and repair. Component costs + OMGS |
| 09- Reduced Capability + Alarm + Loss of Voltage Control + Fail to Operate | Tap changer motor drive defects | Labour costs to investigate and repair. Component costs + OMGS |
| 10- Overheating (will trip on overload) | Overheating due to carbon build up or high resistance contacts in tap changer or overheating due to WTI failure  Contactor/control relay failure Pump failure  Fan failure Incorrect valve position Blockages (sludging)  cooler blockage external | Labour costs to investigate and repair. Component costs + OMGS |
| 11- Cross Contamination of Oil | Gasket leak, drive seal failure, corrosion on diverters | Labour costs to investigate and repair. Component costs + OMGS |
| 12- Alarm + Damaged Component (Tap Changer) No Trip | Diverter mechanism jams due to loose permali nuts | Labour costs to investigate and repair. Component costs + OMGS. May necessitate replacement of tap changer. |
| 13- Alarm + Trip + Damaged Component (Tap Changer) | Selector/diverter fail to complete op or flashover. Diverter open circuit, loss of containment | Labour costs to investigate and repair. Component costs + OMGS. May necessitate replacement of tap changer. |
| 14- Alarm + Trip + Transformer Internal Damage | Selector/diverter fail to complete operation or flashover. Diverter go open circuit, loss of containment - but in this case the transformer is damaged not just the tap changer | Labour costs to investigate and repair. Component costs + OMGS. Significant damage to the transformer windings. |
| 15- loss of oil into secondary containment | Major oil leak, tank breach | Labour costs to investigate and repair. Component costs + OMGS. |
| 16- Alarm + Trip + Damage + State Requiring Replacement (Asset Replacement) | End of Life owing to deterioration | Unit cost for replacement of the asset |
| 17- Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement | Disruptive failure - potential for bushing porcelain projectiles | Replacement of the asset plus costs of replacing/repairing any adjacent assets damaged |
| 18- Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement+ Transformer Fire | Transformer fire | Replacement of the asset plus costs of replacing/repairing any adjacent assets damaged by the fire |

**Table 19**

# 9 Methodology for Calculation of Risk

This section defines how the probabilities and consequences described in previous sections are combined to calculate risk.

For a given asset ($k$), a measure of the risk associated with it is the Asset Risk ($A_k$), given by:

$$Asset\ Risk(A_k) = \sum_{j=1}^{n} P(C_j) \times C_j$$

**Equation 49**

$where$:
$P(C_j) = Probability\ of\ consequence\ \text{j}\ occurring\ during\ a\ given\ time\ period$
$C_j = the\ monetised\ Consequence\ \text{j}$
$n = the\ number\ of\ Consequences\ associated\ with\ Asset\ k$

Figure 16 shows how the components interact and combine together to arrive at a value for Asset Risk.
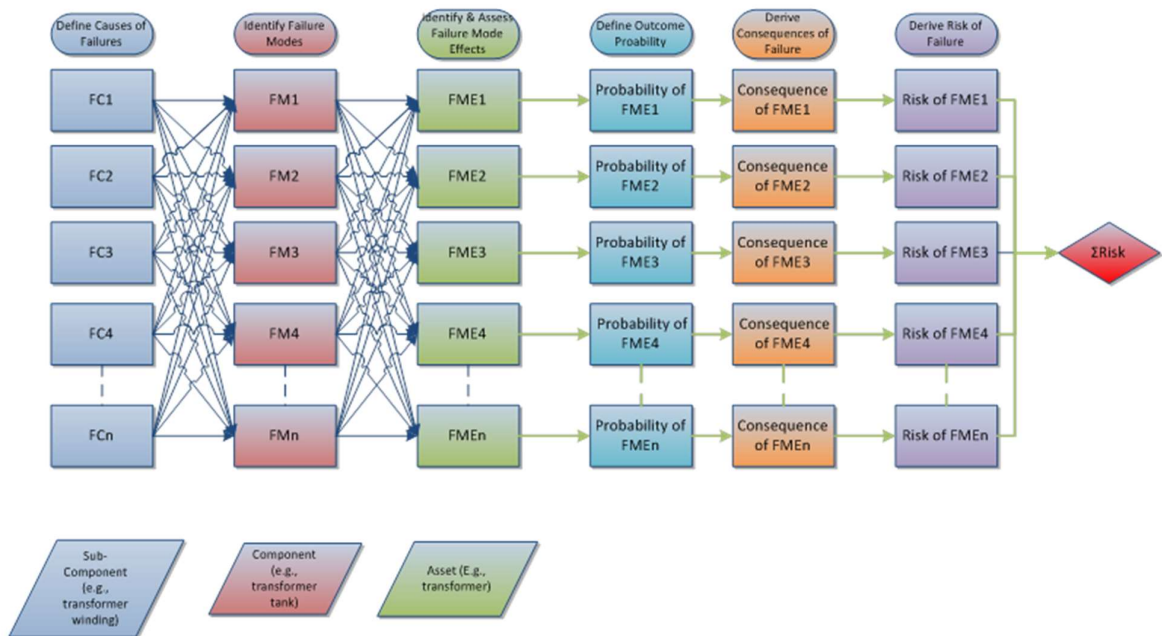


**Figure 16**

The Network Risk for NGET can be calculated by summing the Asset Risk associated with each lead asset as shown in Equation 50.

$$Network\ Risk = \sum_{k=1}^{n} A_k$$

**Equation 50**

BS EN 60812 describes the process for disaggregating systems into their component parts and assessing the probability of functional failures of each component and the consequences of such failures, then aggregating these quantities to obtain an estimate of the overall risk of the system. A failure mode is clearly immaterial if the cost of the analysis of the failure of a component is much greater than value of the risk represented by the failure of that component, because either the probability of failure of a component or the consequence of failure of a component is insufficiently large.

The available evidential and supporting data, suitable for FMEA analysis, is usually imperfect. This may be for a number of reasons, for example, some possible effects and consequences might be material, but have not yet occurred. Similarly, accurate data may not have been captured for failures, even though the effects and consequences have occurred. Effective application of FMEA therefore requires engineering expertise, both to envision material consequences that have not yet occurred and to estimate values which have not been measured and/or recorded and which cannot be reliably calculated from first principles.

There is a further requirement in the Ofgem Direction[8] to enable the identification of all material factors contributing to real or apparent performance against targets.

A non-exhaustive list of these factors is identified in Paragraph 32 of the Direction. In practice, the effect of any of these factors will be a modification to one or more inputs to the methodology. Any factor which does not result in a modification to one or more of the inputs does not contribute to real or apparent performance against targets as measured by this methodology.

For factors that do modify one or more inputs to the methodology, the methodology can be re-run incorporating these input changes and the outcomes compared with the outcomes produced before the changes are applied. Hence not only can factors be identified but also their relative materiality can be determined.

Therefore, if NGET (or Ofgem) suspects that a factor (e.g. data revisions) or change in external environment (business, legal, site or situation) will contribute to real or apparent performance against targets, then the following tests can be made:

1. Check what impact the factor has on existing inputs to the methodology – if the impact is zero then the factor has been positively classified as non-material
2. If impact is non-zero, then re-run the methodology with changed inputs and compare outputs with equivalent outputs with the un-changed inputs – The variation of output can be compared with the variations produced by other factors and ranked in terms of relative materiality

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[8] Ofgem (2016) *Decision to direct modifications to the electricity transmission Network Output Measures Methodology.* Available at: < https://www.ofgem.gov.uk/publications/decision-direct-modifications-electricity-transmission-network-output-measures-methodology>

# 10 Decision Support for Intervention Planning

**Failure modes can be addressed by different interventions including maintenance, repair, replacement, and refurbishment. Not all these options are applicable to all assets or failure modes.**

Certain types of intervention will address particular failure modes. These may be routine interventions, such as maintenance, or specific, such as planned replacements.

The available interventions for managing the performance of assets range from routine maintenance to full replacement.

These activities are undertaken to ensure the longevity and performance of the NGET network. Without effective management of these activities, and understanding the related interactions between them, NGET would, in time, experience deterioration of network outputs which would have a significant detrimental impact on the capability of the network.

Intervention plans are optimised to deliver an efficient level of network risk in line with customer, consumer, and stakeholder expectations. In determining this efficient level, NGET evaluates the cost of interventions against the benefits these interventions deliver.

In determining an intervention plan in any period, NGET needs to assess the Asset Risks and decide exactly which interventions to undertake. This requires NGET to make a binary decision (e.g. to replace, or not to replace) where every asset has an Asset Risk contribution to the Network Risk. This process involves assessing all available interventions to decide the combination which most efficiently manages Network Risk.

The cost of these interventions is not equal to the reduction in Network Risk achieved by undertaking that intervention plan.

Table 20 identifies different types of intervention that would address failure modes, Figure 17 (not to scale) illustrates which failure modes are addressed by the different intervention types.
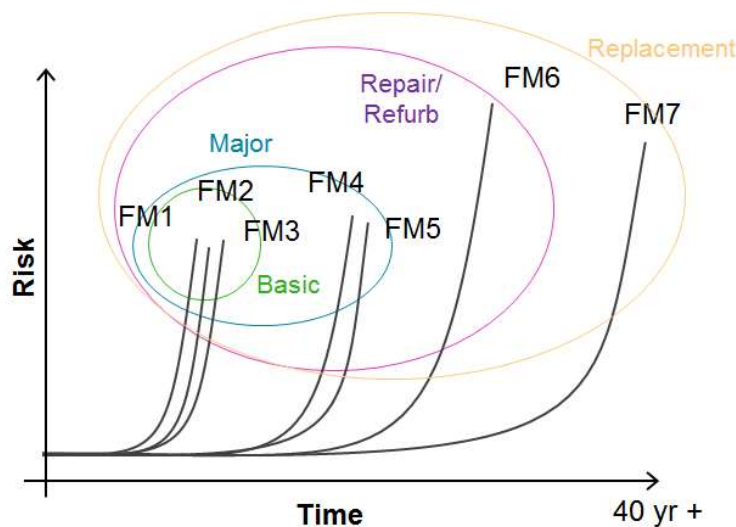


**Figure 17**

| Failure Mode | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| Basic Maintenance | ✔ | ✔ | ✔ | ✗ | ✗ | ✗ | ✗ |
| Major Maintenance | ✔ | ✔ | ✔ | ✔ | ✔ | ✗ | ✗ |
| Repair | ✔ | ✔ | ✔ | ✔ | ✔ | ✔ | ✗ |
| Refurbishment | ✔ | ✔ | ✔ | ✔ | ✔ | ✔ | ✗ |
| Replacement | ✔ | ✔ | ✔ | ✔ | ✔ | ✔ | ✔ |

**Table 20**

Several failure modes can happen within a similar time frame/ duty cycle, so the work to be carried out needs to be selected carefully in order to:
- Ensure that the relevant failure modes are adequately addressed
- Reduce the whole life cost
- Limit the impact of constraints such as outages and resources.

Interventions are determined by understanding how to prevent failure modes and the collection of data to predict failures. Knowing the asset's position on each failure mode curve enables NGET to make a targeted intervention specifically addressing those failure modes most contributing to the risk. Following the intervention the asset risk on the asset is reduced for that particular failure mode.

## 10.1 Maintenance

The purpose of asset maintenance is to ensure that relevant statutory and legal requirements are met, such as those relating to safety and environmental performance, keeping assets in service, as well as allowing NGET to gather condition information so that performance risks are better understood and mitigated.

Through maintenance activities NGET can manage the natural deterioration of asset condition so that the assets remain operable throughout their anticipated technical life, reducing unplanned outages on the network as well as monitoring the condition of assets to improve understand of their performance. This then feeds into future asset intervention plans.

Maintenance is a fundamental tool in NGETs' management of network reliability, safety, and environmental performance (and hence customer satisfaction). Reducing maintenance to zero, or reducing levels without undertaking impact assessments, would lead to a decline in the condition of assets (this effect is seen more rapidly than for under-investment in replacement), leading to increased unplanned events and in some cases bringing forward the need for asset replacement or increasing refurbishment activities.

Maintenance policy evolves as processes and practice are periodically reviewed. NGET reassess maintenance policy on an ongoing basis using the latest information available in order to ensure assets can achieve their anticipated asset lives and reduce the potential for unplanned disruption. Maintenance activity can uncover developing trends for defects, ensure rectification of unforeseen functional failure modes and can be the driver for further innovation in methodologies and techniques for future interventions.

When developing maintenance content, NGET has a systematic, structured method for cost/benefit evaluation. This includes understanding the asset's reliability for known failure modes, taking account of how the operating costs would be expected to increase during the time between interventions; identifying potential changes in performance; and consideration of the impact that a change to the intervention might have on the life of the asset. As part of the planning process, maintenance is bundled into efficient packages to optimise access to the network and the assets.

Maintenance activities are pro-active interventions which take place at regular intervals according to policy. Undertaking maintenance activities ensures that the assets function correctly and can identify issues with the assets which can be addressed prior to a failure mode occurring.

A basic maintenance will involve basic checks for function of particular components as well as activities such as visual inspections, checks for fluid/gas levels where appropriate.

An intermediate maintenance takes place at longer intervals than a basic and will include all activities undertaken for a basic maintenance but will include additional checks on specific components of the equipment.

A major maintenance will include all the activities undertaken for a basic and intermediate maintenance but will also include comprehensive and possibly intrusive work as well as more exhaustive checks. These take place less regularly than basic and intermediate levels and generally require a significantly longer outage to carry out the work.

Maintenance interventions are determined through maintenance policy for each asset type, according to the specific requirements for that asset. Manufacturer recommendations are taken into account, but not necessarily followed.

## 10.2 Repair

Repair is generally a reactive activity responding to a failure mode event when it has occurred or, in some cases, to prevent a particular failure mode if it can be detected before the event occurs. For some failure modes which cannot be detected on a routine basis, such as by maintenance or inspection, repair is the only available intervention once the failure mode has occurred. That is not to say that detection of the failure mode is not available, and assets are monitored for known failure modes. For example, cable oil pressure is monitored, and an alarm triggered if the pressure falls below a certain level. The failure mode is detected as the oil leak initiates but there are no routine interventions available to detect the occurrence of a leak before it occurs.

The only available option is to repair the cable when the oil leak is detected. Some failure modes, which lead to another failure mode, can be detected prior to failure, for example, sheath testing of cables will reveal defects in the oversheath which, if left unrepaired, will eventually lead to the corrosion of the sheath and subsequently an oil leak. A repair intervention can then be planned to mitigate this risk.

## 10.3 Refurbishment

The decision to refurbish instead of replacing an asset follows careful consideration of a number of criteria. For refurbishment to be technically feasible and cost-effective, the asset population size must be sufficiently large because the costs associated with developing the technical content of a refurbishment procedure, and the set-up costs to undertake the work, mean that it is difficult to make refurbishment of small populations cost-effective.

The ongoing lifetime cost of supporting a refurbished asset family must also be considered. It may be more cost-effective to replace highly complex units that require frequent intervention.

Continuing spares support must be considered. Whilst some spares can be re-engineered without significant risk, this is not appropriate for performance critical components. If such components are unavailable (or not available cost-effectively), refurbishment is unlikely to be a realistic option.

Additionally, the condition and deterioration mechanisms of the asset class must be well understood. If these criteria are met, and it is considered that refurbishment is a viable option, it would be expected that refurbishment activities would change the asset's condition and/or extend asset life.

## 10.4 Replacement

Individual assets or families, which are deemed to be a priority given their risk, trigger the need for replacement and capital investment. There may also be instances where the frequency of repair (and associated cost) is such that replacement is considered economic. To facilitate the development of an optimised replacement plan, priority ranked lists for replacement are created for each asset type.

# 11 Calibration, Testing and Validation

The TOs jointly completed a detailed Calibration, Testing and Validation (CTV) for end-of-life failure modes. Maintenance implementation in our respective models is sufficiently different to make calibration near-impossible.

The NARM methodology has been designed to enable the parameters to be easily adjusted to reflect the results of the CTV exercises. The CTV exercises include scenarios and tests, and defined criteria are set out prior to the test and the results are compared against these criteria. A summary of the CTV elements and results can be found in appendix B.

## 11.1 Calibration

The purpose of calibration is to:
- Ensure that each TO produces credible CoF, EoL modifiers and PoF values that are representative of the impacts of actual asset failures.
- Ensure that each TOs input values and assumptions are consistent and comparable.

## 11.2 Testing

The purpose of testing is to:
- Ensure that each TO has implemented correctly in line with the NOMs methodology.
- That the each TOs implementation of the NOMS methodology works across a suitable range of credible scenarios.

## 11.3 Validation

The purpose of validation is to:
- Ensure that each TOs implementation of the NOMs methodology produces comparable results.
- Ensure that the NOMs methodology produces realistic and credible values.

## 11.4 Delivery of CTV

The TOs have worked together to compare the performance of their respective risk models.

A separate document was produced following CTV detailing the work carried out and data sources used; listing the calibration that has been applied as a result of CTV and demonstrate comparability across TOs. Issue 4 of the NARA incorporated the findings of the CTV exercise.

# 12 Implementation

The NARM methodology is now a key part of the RIIO-T2 settlement. NGET has been working to develop the NARM methodology, and there is a continued focus on upskilling our staff and embedding the new ways of working into our business processes.
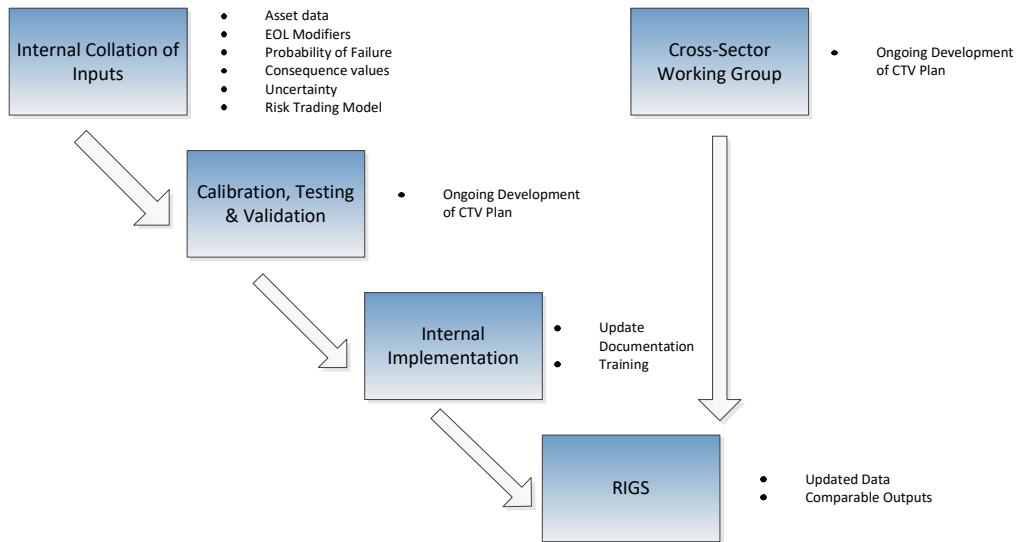


**Figure 18**

# 13 Asset Specific Details

## 13.1 Circuit Breakers
## 13.1.1 Background

Circuit breakers generally have limited condition information on an individual asset basis. To gather additional condition information on sub-components and assemblies that have the potential to affect the end of life (EoL) modifier, would require invasive work to assess actual condition. It is not economically favourable to do this for every single asset and each of its failure mode items, based on the balance of intervention cost and failure risk.

Non-outage, non-intrusive diagnostic techniques, including continuous monitoring, do not detect all failure mode effects linked to the end of life of circuit breakers and also have economic limitations (e.g. it is not favourable to retrofit all gas circuit breakers with permanent online monitoring).

The distribution of deterioration within a population is impacted by equipment environment, electrical and mechanical duty, maintenance regime and application.

In this methodology a family specific deterioration component to the EoL modifier formula is introduced to account for missing condition information. Assignment to family groupings is through identification of similar life limiting factors. Family groupings are broadly split into interrupter mechanism types.

Known deterioration modes have been determined by carrying out analysis of materials and components during replacement, refurbishment, maintenance, and failure investigation activities or following failures. The output of the analysis reports has been used to both inform and update the relevant deterioration models. Anticipated technical asset lives are based on the accumulated engineering knowledge of NGET's defect and failure statistics and manufacturer information. The method for mapping this knowledge to the end of life curve was presented in the failure modes and effects analysis section.

## 13.1.2 Deterioration

Circuit breakers are made up of several sub-components or assemblies. These deteriorate at different rates, are different in relation to their criticality to the circuit breaker function and finally have different options regarding intervention

Although there is a correlation between age and condition, it has been observed that there is a very wide range of deterioration rates for individual units. The effect of this is to increase the range of circuit breaker condition with age, some circuit breakers becoming unreliable before the anticipated life and some showing very little deterioration well after that time.

## 13.1.3 Air-blast Circuit Breakers

Using the above approach, refurbishment has, in selected cases, proven to be an effective way to extend the Anticipated Asset Life (AAL) for Conventional Air-Blast (CAB) and Pressurised head Air Blast (PAB) circuit breakers.

The replacement of ABCBs is considered alongside the remaining lifetime of the associated site air system. If removal of the last ABCBs at a site allows the site air system to be decommissioned, early switchgear replacement may be cost beneficial when weighed against further expenditure for air system replacement and/or on-going maintenance.

Cost-benefit analysis of eliminating ABCB should also consider the benefit of eliminating the complex and expensive air systems they are associated with. The risk model does not know about these elements.

Air- blast circuit breakers are technologically obsolete, and out of manufacture. A replacement at this time at 400kV or 275kV would likely be an SF6-type breaker, although alternative SF6-free circuit breakers are coming to market.

### 13.1.4 Oil Circuit Breakers

The life-limiting factor of principal concern is moisture ingress and the subsequent risk of destructive failure associated with the BL-type barrier bushing in bulk Oil Circuit Breakers (OCBs). A suitable replacement bushing can be exchanged when moisture levels reach defined criteria, but at a high cost to the extent that it is not economically favourable to replace many bushings within the population. Risk management of bushings has been achieved by routine oil sampling during maintenance, subsequent oil analysis and replacement of bushings and even whole circuit breakers where required.

Bulk Oil circuit breakers are obsolete, and out of manufacture. Similarly, to air-blast circuit breakers the alternative technology presently for 275kV units (our highest design voltage in this class) is an SF6 gas circuit breaker.

### 13.1.5 SF6 Gas Circuit Breakers

Gas Circuit Breakers became widespread in their application from the early 1980's. They are compact, with fewer breaks per phase and a much simpler mechanism and interrupter assembly when compared with air blast circuit breakers. Consequently, their ongoing maintenance costs are comparatively low. There is a correlation between time in service, operating environment and SF6 emissions. This poor environment performance is a driver for investment in this population, alongside deterioration of operating mechanisms, interrupter assemblies and obsolete control systems. A similar process to that followed for the ABCB families is being undertaken to identify refurbishment (i.e. life extension) opportunities. Where this is not technically feasible or cost-effective, replacement is planned. The availability of SF6 alternatives is factored into this decision making.

The GCB population includes a diverse range of smaller families, with variants and differing operating regimes, and so the identification of large-scale refurbishment strategies may not be cost-effective. Technical and economic evaluation as well as further development of refurbishment strategies will take place.

A significant number of SF6 circuit-breakers which are installed on shunt reactive compensation are subject to very high numbers of operations (typically several hundred per year). The "end of life" of these circuit-breakers is likely to be defined by number of operations ("wear out") rather than age-related deterioration. To assist with asset replacement planning, these circuit-breakers have been assigned a reduced asset life in this document based on a prediction of their operating regime. Different asset lives have been assigned depending on the circuit breaker mechanism type and/or if the circuit breaker has been reconditioned; in each case the asset life is based on an operating duty of 300 operations per year. It is currently proposed to recondition most types of high duty reactive switching circuit breaker when they have reached their anticipated asset life based on the number of operations they have performed.

### 13.1.6 Circuit Breaker EoL modifiers - Examples
These examples previously appeared in the Licensee-specific appendices. They have been anonymised for inclusion in the public document.

### 13.1.6.1 Circuit Breaker Example 1
The breaker is a Reyrolle OB14 Air Blast Circuit Breaker, installed in 1961. The design and support from the OEM is considered as Obsolete, with a declining population of grey spares. Historically, this class of breaker has a known history of end-of-life failure modes, which when combined with the declining population of components aligns to the asset family assumptions of a 45-year lifespan.

$$EOLmod = \max{(AGE_{FACTOR}, DUTY_{FACTOR}, SF6_{FACTOR}, DEFECT_{FACTOR}, FAMILY_{FACTOR})}$$
**Equation 51**

This asset is classed as in poor condition based on the data that is available. Its EoL modifier score is 100. Due to both design and maintenance regime, operational duty, fault current and SF6 are not determining factors in application of EoL modifier.

### 13.1.6.2 Circuit Breaker Example 2

The breaker is a GEC FE2 275kV gas circuit breaker, which is assigned to the 300kV gas circuit breaker, hydraulic mechanism group. It has an anticipated asset lifetime of 30 years. Family level assessment of the hydraulic systems including the nitrogen accumulator and operating mechanism has identified life-limiting factors of these major components.

Examples include seal deterioration within the mechanism, leading to reduced performance in time of operation, and the gradual loss of nitrogen pressure within the accumulator due to leakage or passing of hydraulic fluid. Furthermore, a significant number of FE circuit breakers have an electronic control system, the life of which is limited. The Mk1 variant of the control system has demonstrated significant life limiting factors requiring replacement of this functionality for ongoing reliable operation.

Other factors include the number of operations performed (1819) which is approaching the upper limit for this mechanism type and demonstrating a low-level of continuous SF6 leakage. While the total is low, the leak rate is nonetheless significant resulting in a EoL modifier of 60 being applied for this characteristic alone.

The breaker was installed in 1987, 30 years old as of 2017. Time in service is a factor in assessment of the asset risk and leads to an overall EoL modifier of 83.

### 13.1.6.3 Circuit Breaker Example 3

Installed in 1993, this asset is a Reyrolle SPD2 400kV GIS asset. The age and operational duty do not play a major factor. The asset has demonstrated an increasing trend of SF6 leaks; to the point that in 2017 it had leaked 22kg of SF6. While this is low compared to the overall inventory of the gas zone, the leak rate is ~4% and has EoL modifier 60 for this factor alone.

Intervention on this asset will be completed to OEM recommendations and depending on the location of the leakage, either changes to the seals and desiccants, or, if there is corrosion of flanges, machining to remove imperfections may be required.

### 13.1.6.3 Circuit Breaker Example 4

This asset is amongst the oldest GIS installations on the National Grid system. Its design is obsolete, and the OEM does not support the asset. This example has exceeded the anticipated lifetime of 30, by 13 years, which immediately leads to an EoL modifier of 100. The score is validated further by the SF6 leakage score; the gas zone is reported to be leaking over 100kg per year leading to an EoL modifier of 100. Replacement of the asset was recommended.

## 13.2 Transformers & Reactors
### 13.2.1 Background

Transformers and reactors share similar end of life mechanisms since they are both based on similar technologies. The same scoring method is therefore applied to calculate the EoL modifier. For simplicity within this section the term transformer is used to mean both transformer and reactor.

Transformers are assigned an EoL modifier according to the condition inferred from diagnostic results, the service history, and post mortem analysis of other similar transformers.

The health of the overall transformer population is monitored to ensure that replacement/refurbishment volumes are sufficient to maintain sustainable levels of reliability performance, to manage site operational issues associated with safety risks and to maintain or improve environmental performance in terms of oil leakage.

The process by which transformers are assigned an EoL modifier relies firstly on service history and failure rates specific to particular designs of transformers and secondly on routine test results such as those obtained from Dissolved Gas Analysis (DGA) of oil samples. When either of these considerations gives rise to concern, then where practicable, special condition assessment tests (which usually require an outage) are performed to determine the appropriate EoL modifier. Special condition assessment may include the fitting of a continuous monitoring system and the analysis of the data to determine the nature of the fault and the deterioration rate.

The elements to be taken into account when assigning an EoL modifier are:

1.  Results of routine condition testing
2.  Results of special condition assessment tests
3.  Service experience of transformers of the same design, and detailed examination of decommissioned transformers
4.  Results of continuous monitoring where available

The following additional condition indications shall be taken into account when deciding the repair/replacement/refurbishment strategy for a particular transformer:

1.  Condition of oil
2.  Condition of bushings
3.  Condition of coolers
4.  Rate of oil loss due to leaks
5.  Condition of other ancillary parts and control equipment
6.  Availability of spare parts particularly for tap-changers

### 13.2.2 Deterioration

Thermal ageing of paper is the principal life limiting mechanism for transformers which will increase the failure rate with age. This failure mechanism is heavily dependent on design and evidence from scrapped transformers indicates a very wide range of deterioration rates. Knowledge of the thermal ageing mechanism, other ageing mechanisms and the wide range of deterioration rates are used to define the anticipated asset lives for transformers.

In addition to the above fundamental limit on transformer service life, experience has shown that a number of transformer design groups have inherent design weaknesses which reduce useful service life

The condition of transformers can be monitored through routine analysis of dissolved gases in oil, moisture, and furfural content together with routine maintenance checks. Where individual test results, trends in test results or family history give cause for concern, specialist diagnostics are scheduled as part of a detailed condition assessment. Where appropriate, continuous monitoring will also be used to determine or manage the condition of the transformer.

Methods exist to condition assess transformers and indicate deterioration before failure, however the time between the first indications of deterioration and the transformer reaching a state requiring replacement is varied and can depend on factors such as the failure mechanism, the accuracy of the detection method, and the relationship between system stress and failure. For this reason the transformer models periodically require updating (supported by evidence from post-mortem analysis) as further understanding of deterioration mechanisms is acquired during the transformer life cycle.

### 13.2.3 Insulating Paper Aging

The thermal ageing of paper insulation is the primary life-limiting process affecting transformers and reactors. The paper becomes brittle, and susceptible to mechanical failure from any kind of shock or disturbance. Ultimately the paper will also carbonise and cause turn to turn failure, both mechanisms leading to dielectric failure of the transformer. The rate of ageing is mainly dependent upon the temperature and moisture content of the insulation. Ageing rates can be increased significantly if the insulating oil is allowed to deteriorate to the point where it becomes acidic.

The thermal ageing of paper insulation is a chemical process that liberates water. Any atmospheric moisture that enters the transformer during its operation and maintenance will also tend to become trapped in the paper insulation. Increased moisture levels may cause dielectric failures directly or indirectly due to formation of gas bubbles during overload conditions.

The paper and pressboard used in the construction of the transformer may shrink with age which can lead to the windings becoming slack. This compromises the ability of the transformer windings to withstand the electromagnetic forces generated by through-fault currents. Transformer mechanical strength may be compromised if it has experienced a number of high current through faults during its lifetime and the internal supporting structure has been damaged or become loose.

End of life as a result of thermal ageing will normally be supported by evidence from one or more of the following categories:

1. Post-mortem (scrapping) evidence (including degree of polymerisation test results) from units of similar design and load history
2. High and rising furfural levels in the oil
3. High moisture content within the paper insulation
4. Evidence of slack or displaced windings (frequency response tests or dissolved gas results)

### 13.2.4 Core Insulation

Deterioration of core bolt and core-to-frame insulation can result in undesirable induced currents flowing in the core bolts and core steel under certain load conditions. This results in localised overheating and risk of Buchholz alarm/trip or transformer failure as free gas is generated from the localised fault. It is not normally possible to repair this type of fault without returning the transformer to the factory. Evidence of this end of life condition would normally be supported by DGA results together with evidence from decommissioned transformers of similar design. Insertion of a resistor into the core earth circuit can reduce or eliminate the induced current for a period of time.

### 13.2.5 Thermal Fault

Transformers can develop localised over-heating faults associated with the main winding as a result of poor joints within winding conductors, poor oil-flow or degradation of the insulation system resulting in restrictions to oil flow. This is potentially a very severe fault condition. There is not normally a repair for this type of fault other than returning the transformer to the factory. Evidence of this end of life condition would normally be supported by dissolved gas results together with forensic evidence from decommissioned transformers of similar design.

### 13.2.6 Winding Movement

Transformer windings may move as a result of vibration associated with normal operation or, more commonly, as a result of the extreme forces within the winding during through fault conditions. The likelihood of winding movement is increased with aged insulation as outlined above. Where evidence of winding movement exists, the ability of the transformer to resist subsequent through faults is questionable and therefore the unit must be assumed not to have the strength and capability to withstand design duty and replacement is warranted. There is no on-site repair option available for this condition. Winding movement can be detected using frequency response test techniques and susceptibility to winding movement is determined through failure evidence and evidence of slack windings through dissolved gas results.

### 13.2.7 Dielectric Fault

In some circumstances transformers develop dielectric faults, where the insulation degrades giving concern over the ability of the transformer to withstand normal operating voltages or transient overvoltage. Where an internal dielectric fault is considered to affect the main winding insulation, irreparable damage is likely to ensue. This type of condition can be expected to worsen with time. High moisture levels may heighten the risk of failure. Evidence of a dielectric problem will generally be based on operational history and post-mortem investigations from units of similar design, supported by DGA. Various techniques are available to assist with the location of such faults, including partial discharge location techniques. If evidence of an existing insulation fault exists and location techniques cannot determine that it is benign, then the transformer should be considered to be at risk of failure.

### 13.2.7 Corrosive Oil

In certain cases, high operating temperatures combined with oil containing corrosive compounds can lead to deposition of copper sulphide in the paper insulation, which can in turn lead to dielectric failure. This phenomenon may be controlled by the addition of metal passivator to the oil, however experience with this technique is limited and so a cautious approach to oil passivation has been adopted. Regeneration or replacement of the transformer oil may be considered for critical transformers or where passivator content is consumed quickly due to higher operating temperatures.

### 13.2.8 Transformer Case Study 1

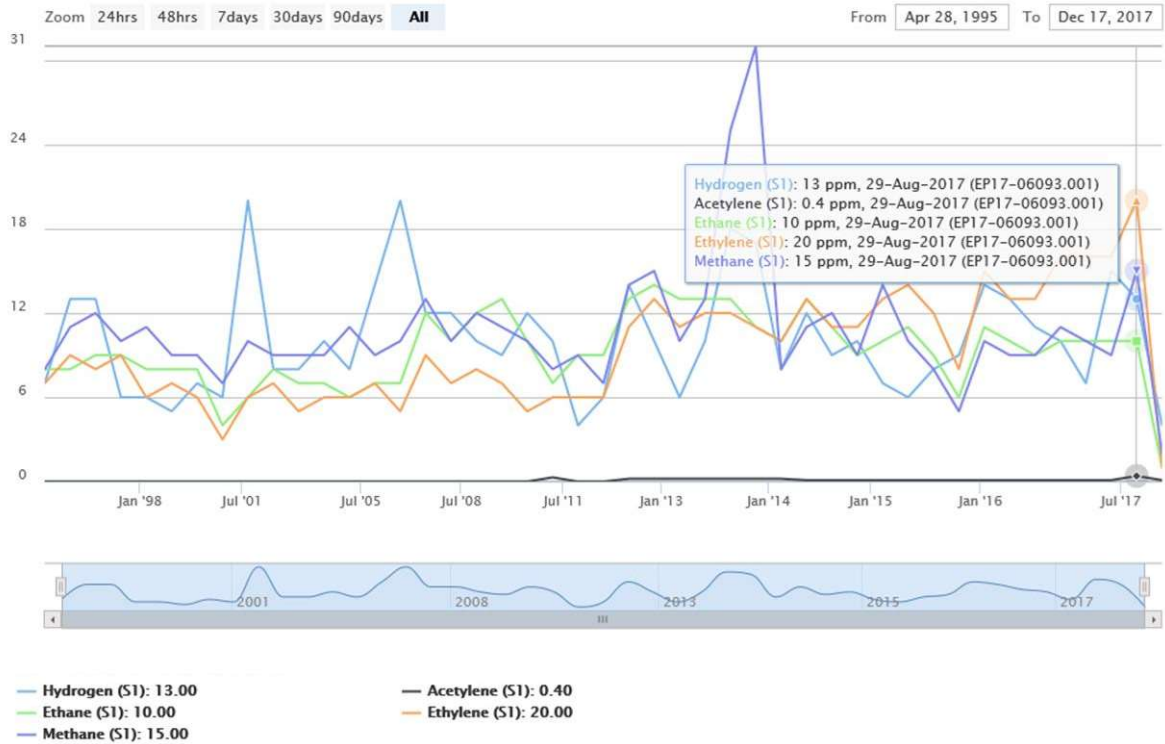No acetylene and normal levels of gas in main tank. Score zero (0).

Figure 19

## 13.2.9 Transformer Case Study 2

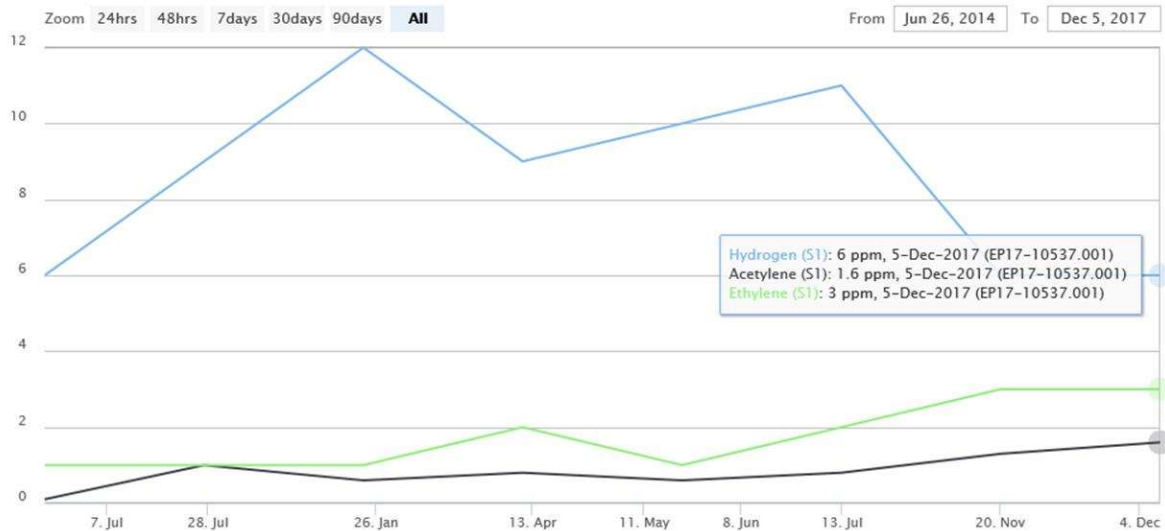Low levels of acetylene in main tank since commissioning. EoL Score 2.



Figure 20

## 13.2.10 Transformer Case Study 3

Installation from 2012. Evidence of low-level arcing/sparking fault. Repair being managed under warranty. EoL score 10.



**Figure 21**

## 13.2.11 Transformer Case Study 4

Evidence of overheating fault in main tank. The bushings were changed in 2014/15, however gas is trending up again.
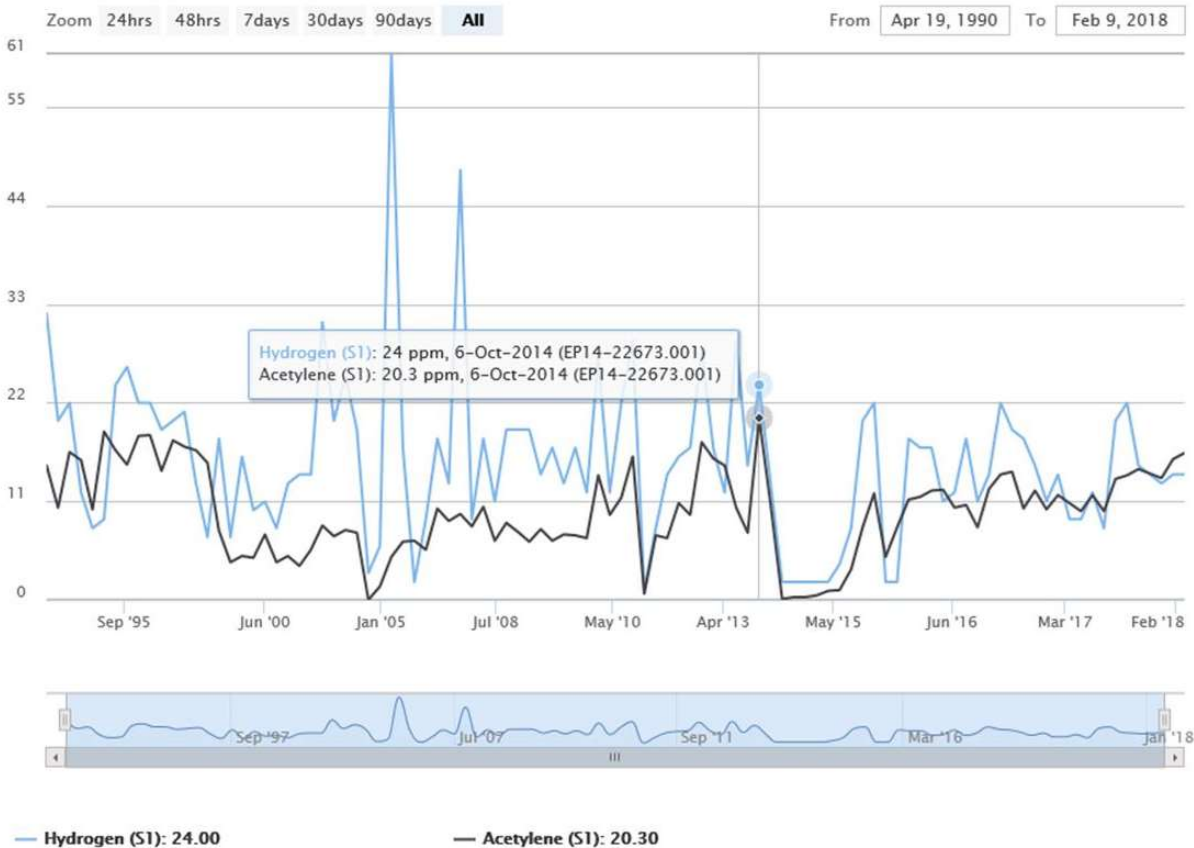


**Figure 22**

### 13.2.11 Transformer Case Study 4

This unit was installed in 2014. There is evidence of a worsening arcing/sparking fault in the high acetylene level. A repair is being managed under warranty.
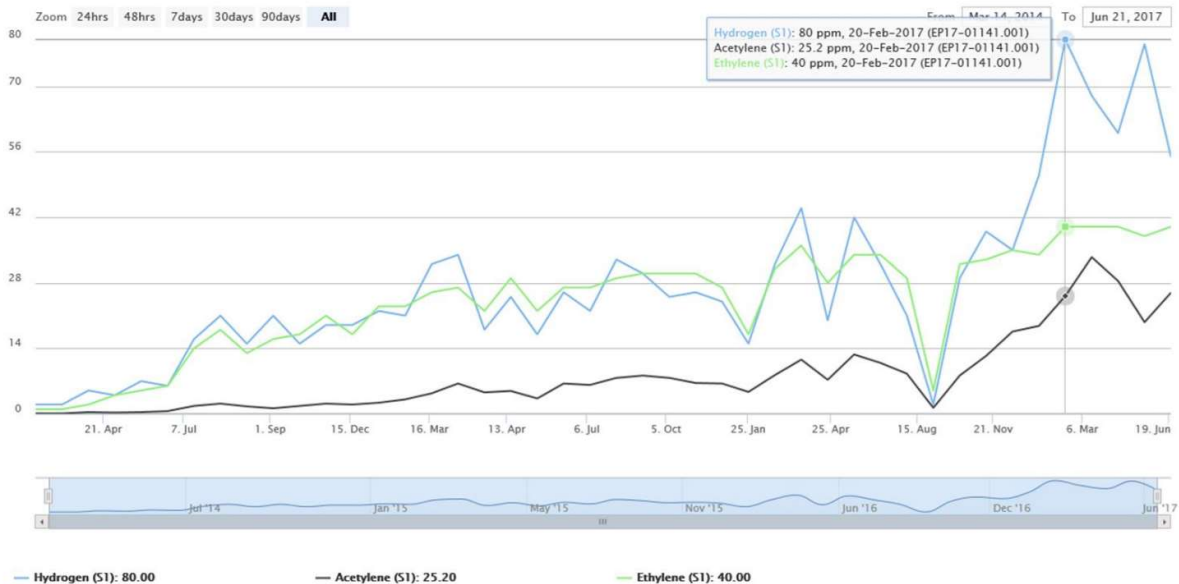


**Figure 23**

## 13.3 Cables
### 13.3.1 Background

Cable system replacements are programmed so that elements of the cable systems are replaced when the safety, operational or environmental risks of continued operation meet defined criteria.

Replacement of cable systems are based on a number of metrics, including age. Reactive measures to evaluate cable condition, such as the nature and quantity of defects are well established. Pro-active measures for cables condition are less readily available. Opportunities to dissect a cable are rare; and non-invasive inspection techniques are, with few exceptions (e.g., sheath testing), relatively immature technologies. The end of life assessment of underground cables are therefore heavily reliant on reactive measures.

The factors considered when determining an EoL modifier include:

1. Historical environmental performance
2. Historical unreliability
3. Risk of tape corrosion or sheath failure
4. Results of condition assessment and other forensic evidence
5. Service experience of cable systems of similar design
6. Number of defect repairs
7. Number of cable faults
8. Duty - time spent at high temperature
9. Duty - frequency of switching activities
10. Bespoke issues associated with specific cable systems; examples may include geophysical phenomena such as subsidence or erosion; or civil engineering factors external to the cable, that impact condition.

This list of factors is not exhaustive. Should new evidence come to light of a previously unconsidered factor, due consideration will be given to further updating this Annex.

### 13.3.2 Deterioration

End of technical life will generally be due to the deterioration of the main cable system; this may be associated with mechanical or electrical integrity or withstand capability.

With the exception of cables vulnerable to reinforcing tape corrosion and cables where a known manufacturing defect has occurred (e.g. lead sheath deterioration), cable systems have generally given reliable operation and there is limited experience of long term deterioration mechanisms.

Cables can be split broadly into two classes for the purposes of understanding the end of life of this asset class, these are fluid filled cables and solid dielectric cables. In general the cable circuit will only meet the criteria for replacement where refurbishment as described above will not address condition and performance issues and guarantee compliance with statutory requirements.

### 13.3.3 End-of-life Mechanisms Common to All Cables
### 13.3.3.1 Lead and Aluminium Sheath Deterioration
Fatigue and intercrystalline cracking, and defects introduced during manufacture can cause oil leaks to develop. It is not generally possible to predict when a given cable section will fail as a result of this failure mode. Local repairs are not generally effective as sheath deterioration is usually distributed along the cable. End-of-life is reached where sheath deterioration is resulting in significant and widespread oil-loss (relative to duties in respect of recognised code of practice) along the cable length.

Cable oversheaths may be at risk of deterioration as a result of abrasion following thermo-mechanical forces incurred in operation. Performance of oversheath materials have in a limited number of cases been identified as a potential source of problems for the sheath.

### 13.3.3.2 Bonding Systems
Water ingress to link boxes causes deterioration of cross-bonding systems and leaves the link box and its Sheath Voltage Limiters (SVLs) vulnerable to explosive failure under fault conditions. Specific evidence shall be gathered through condition assessment to support end-of-life determination. This issue will in general be addressed by replacement of specific components during circuit refurbishment activity or routine maintenance.

### 13.3.3.3 Cooling Systems
Where installed, the life of a cable's cooling system is usually shorter than the lifetime of the cable conductors asset. Therefore, mid-life intervention may be required to replace the cable cooling system components. While this is not the end of the life of the cable, it is an important consideration as the cable is not able to do what it was designed to do with a failed cooling system. Cooling systems tend to be of bespoke design and hard to classify in the context of an asset family FMEA. Loss of the cooling capacity can typically reduce circuit rating by 40%. Aluminium cooling pipes are vulnerable to corrosion and plastic pipes are vulnerable to splitting, which can result in water leaks. Cooling control system and pumping equipment will also require replacement prior to the main cable system in line with circuit specific assessment. In general cooling pipework is managed through maintenance to achieve the asset life of the main cable system.

### 13.3.4 Fluid Filled Cable End of Life Mechanisms
### 13.3.4.1 Reinforcing Tape Corrosion

Reinforcing tapes are used to retain the oil pressure for cables with lead sheaths. Corrosion of the tapes in certain early BICC cables and AEI cables results in the tapes breaking, the sheath splitting and consequential oil leaks. Methods are being developed for predicting failure using corrosion rates determined through sampling in combination with known operating pressures, and also using degradation mechanism models. Local repairs are not considered effective mitigation as corrosion is usually distributed along the cable. End-of-life of the cable system is in advance of widespread predicted tape failure. The lead times for cable replacement schemes are considerably greater than the time to deteriorate from broadly acceptable to unacceptable cable system performance for this failure mode. This implies that pre-emptive action is required to minimise the likelihood of failure occurring. Acceptable performance is where the cable can be repaired on an ad-hoc basis; unacceptable performance is where the corrosion is distributed along a significant number of sections of the route.

The majority of cable vulnerable to this type of corrosion are already programmed for replacement, with relatively few examples expected to survive beyond 2030.

### 13.3.4.2 Stop Joint Deterioration

Stop-joint failure presents significant safety, reliability, and environmental risk. End-of-life for stop joints will be justified based upon oil-analysis data or forensic evidence from similar designs removed from service. Stop joint deterioration can be addressed via refurbishment and would not alone drive replacement of the cable system.

### 13.3.4.3 Cable Joint Deterioration

In general cable joint deterioration can be addressed via refurbishment and would not alone drive replacement of the joint or cable system.

### 13.3.4.4 Oil ancillaries

Corrosion of oil tanks, pipework and connections, and pressure gauges can result in oil leaks and incorrect operation of the ancillaries. Specific evidence shall be gathered through condition assessment to support end-of-life determination. This issue will in general be addressed by replacement of specific components during circuit refurbishment activity or enhanced routine maintenance.

Oil systems are likely to be out-lasted by the cable conductors they support.

### 13.3.4.5 Environmental Considerations

NGET has a statutory obligation to comply with the Water Resources Act 1991/Water Resources (Scotland) Act 2013 and to fulfil its commitments, with respect to its Environmental Statement. Utilities demonstrate compliance with the requirement of the Act through adherence to the guidance provided.

A factor to consider in determining anticipated asset life is when it is no longer reasonably practicable to comply with the requirements of the above legislation and guidance and maintain a sustainable level of circuit availability.

### 13.3.5 Solid, XLPE Insulated Cable End of Life Mechanisms

Transmission circuits have been installed at 132kV and 275kV since 1988 in the UK. Limited examples at lower voltages in substations exist back to 1968. Globally, there is only limited service experience at 400kV or above. These types have mostly been installed over similar time frames to the NGET asset base. The existing asset lifetime estimates are largely based on the tests conducted at type registration, e.g. the time to fault when tested at voltages very much greater than that intended for operational use. Statistics were then used to justify the probability a cable would reach a specific age. End of life mechanisms have not been encountered in the UK at this time. The long-term deterioration mechanisms are an obvious candidate for further research.

Possible failure modes[9] that XLPE cables may exhibit are:

- Insulation deterioration due to natural ageing due to thermal cycling, mechanical aggression, and defects.
- Polyethylene oversheaths have known risks of photo- and thermal-degradation into lactones, esters, ketones and carboxylic acid.
- Water treeing, arising from partial discharge in a cable. This failure mode arises mostly as a result of moisture ingress, which itself can arise from outer sheath damage, poor or non-existent water barriers or outer metallic sheath corrosion. It should be noted that moisture can penetrate even an intact oversheath; albeit Polyethlyene is a much better barrier than PVC as used on older cable technologies.
- Electric treeing due to a defect in the insulation, partial discharge, or thermal ageing. Such a defect could also occur at cable joints as the risk of contamination is considerably higher for such an assembly in the field rather than the clean-room conditions of the production line.
- Arcing from phase conductor to the outer sheath. Such a fault is unlikely without external influences, such as excessive mechanical force on the cable sheath, or deformation of the conductor and insulation.
- Thermal runaway, in the event that the material surrounding the cable does not possess the thermal conductivity and heat capacity appropriate to the losses encountered on the cable. Thermal runaway is possible as a result of third party influences; for example where burial depths are unintentionally increased without notification.

NGET does not at this time have experience of all these failure modes. Circuit loadings inherent to design of the system to the SQSS in routine operation, are relatively low. The populations are also relatively young. The failure modes listed are highly interlinked, for example the condition and quality of the cable installation have bearing on the risk of water treeing and arcing. The deterioration of the insulation appears mostly to be associated with the age of the cable, though operational duty and installation environment also appear to have bearing on condition. Research has been published in a number of journals concerning the effect of long term operation at high temperature and the change in chemical composition and insulation effectiveness over time. Evaluation of condition is, unfortunately, problematic without destructively testing the cable, there is therefore a strong desire to devise and deploy alternative means of evaluating condition rather than relying on age as an indicator alone.

### 13.3.6 Cable End-of-life Modifier examples
### 13.3.6.1 Cable End-of-life Modifier example 1

This circuit consists of two separate cables: and overhead line, and its associated switchgear. The EoL modifier is calculated for all cables in this circuit separately. The overall EoL modifier is 81.

EoL modifier is given by

$$EOLmod = ACS + Sub_{ADJ}$$

Where
$$ACS = (AALc * GFR) + DUTY + \max(DEFECTS, SEVERITY) + ACCESS + \max(OIL, PROIL) + Main\_ADJ$$

**Equation 52**

Where ACS is the main asset condition score and Sub_Adj is the sub-asset condition score adjustment.
In this example, ACS = (2*3) + 0 + 35 + 10 + 0 + 10 = 71

This system was installed in 1968. One section is classified as a category 1 cable, with asset lifetime of 70 years. The other is Category 3, with anticipated life of 55 years. We assume the worst, therefore age of 55 applies, leading to an AALc component of 2.

GFR weighting is 3 because of the presence of the Category 3 cable.

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[9] *EA Technology - Reducing Failure Rates and Better Management of Underground Cable Networks*

The circuit is not operated under especially heavy duty, this scores zero on this aspect.

The circuit has experienced 40 defects in the last 10 years, and so is assigned a score of 35 for its operating history. Oil leaks are scored 10, as there is a pro-rata oil leakage of 413 litres over the last 10 years.

Category 3 cables have a known propensity for bronze tape corrosion. Main_Adj is therefore 10.

There have also been historical failures of the diving bell link boxes (EoL 5), oil leaks (EoL 5) on these cables. Sub_adk is therefore set to 10.

Many of the defects are associated with the category 3 cable; and there is at least one suspected incident of malicious third party interference leading to fire damage. The route is adjacent to a river, and penalties have been incurred as a function of environmental impact. While the route score is poor, investigation suggests that targeted replacement of the Category 3 cable is the most cost effective course of action. The other cable is not as high a priority replacement and can safely be deferred.

The category 3 cable was originally scheduled for replacement in 2020/21 as part of RIIO-T1; however, operational risks associated with placing certain demands at single-circuit risk plus COVID-related concerns delayed this work to early RIIO-T2. It has now been replaced.

### 13.3.6.2 Cable End-of-life Modifier example 2

This circuit is one of the poorest condition cable assets, with an EoL modifier that would total 131. The score is capped at 100, as with all asset categories.

It was installed in 1967 and is a Category 3 cable with known propensity to bronze tape corrosion. It's anticipated lifetime is 55 years.

$$ACS = (AALc * GFR) + DUTY + \max(DEFECTS, SEVERITY) + ACCESS + \max(OIL, PROIL) + Main\_ADJ$$

**Equation 53**

ACS = (2 * 3) + 0 + 40 + 40 + 15 + 10 = 111.

This asset has experienced 229 defects in the last 10 years, and so scores 40 for that. The time spent repairing defects is high at 5940 hours, so scores 40 for this. Oil leaks totalling 4900 have been reported, scoring 15 (pro-rated oil score of 5). These issues sum together to drive the EoL modifier score towards a high value. This case demonstrates how a substantial number of issues can aggregate together to push a cable asset towards a state requiring replacement.

Sub adjustment factors applicable to this cable include risks associated with stop joint failure (5), SVL failure (5) and multiple sheath faults (10). The sub_adj total is therefore 20.

The overall EoL modifier score is therefore 111+20=131.

This asset is part of an ongoing replacement programme; the lead time for completion has been over 10 years.

### 13.3.6.3 Cable End-of-life Modifier example 3

This circuit has been assigned a relatively good condition EoL modifier of 20. The oldest cable was installed in 1960 and is of Category 2 (EoL modifier 5). There have been 10 defects in the last 10 years (EoL modifier 15). All other scoring components score zero. This circuit is considered to be a relatively low replacement priority, in spite of age.

## 13.4 Overhead Lines
### 13.4.1 General Approach

Routes are fully refurbished, or have critical components replaced, to maintain reliability (including a level of resilience to extreme weather conditions), operational risk and safety performance. In addition, conductors should retain sufficient residual mechanical strength to facilitate safe replacement by tension stringing methods at end of life.

Technical asset lives for OHL components in various environments have been predicted using historical condition information from previous OHL replacement schemes, condition samples taken on existing assets, and an understanding of deterioration mechanisms.

Scoring assessments are made on sections of circuit that are typically homogenous in conductor type, installation date and environment.

#### 13.4.1.1 Deterioration of Conductors

Conductor end of life condition is a state where the conductor no longer has the mechanical strength (both tensile and ductility) required to support the combination of induced static and environmental loads.
Two main deterioration mechanisms exist:

1. Corrosion, primary cause pollution either saline or industrial
2. Wind induced fatigue, common types
   a. AEoLian vibration (low amplitude high frequency oscillation 5 to 150 Hz)
   b. sub-conductor oscillation (bundles conductors only) produced by forces from the shielding effect of windward sub-conductors on their leeward counterparts
   c. galloping (high-amplitude, low-frequency oscillation)
   d. wind sway

Conductor fatigue is usually found at clamp positions where the clamp allows more interstrand motion within the conductor, leading to fretting of the internal layers. Loss of strand cross-section follows, then fatigue cracking, and finally strand breakage. This form of degradation is generally the life-limiting factor for quad bundles, clamping positions on twin bundles can also be affected

Conductor corrosion is also usually found at clamp positions. Interwoven conductor strands open up at these points allowing for easier ingress of corroding chlorides, sulphates, and moisture etc. The zinc galvanising of the core wires is corroded, eventually exposing the underlying steel. A galvanic corrosion cell is then created where the aluminium wire is sacrificial. The loss of cross section of aluminium leads to greater heat transfer to the steel core increasing the risk of core failure. Additionally, some spacer clamps with elastomer bushings that contain carbon and have a low resistance also lead to galvanic corrosion of aluminium strands, reducing thickness, strength, and ductility.

In addition end of life may be advanced, in rare instances, due to an unexpected load or events such as extreme

It should be noted that while Conductor risk is not a factor in RIIO-T2 outcomes, it is still reportable in annual RRP.

#### 13.4.1.2 Deterioration of Insulators

The end of life occurs when the increased risk of flashover (loss of dielectric strength) reaches an unacceptable level due to condition, which may or may not result in mechanical failure of the string, or a decrease in mechanical strength due to corrosion of the steel pin.

#### 13.4.1.3 Deterioration of Fittings – Spacers, Spacer Dampers & Vibration Dampers

The functional end of life of spacers, spacer dampers and vibration dampers occur at the point at which the conductor system is no longer protected, and conductor damage starts to occur.

These items are utilised to protect the conductor system from damage. The main deterioration mechanism is wear or fatigue induced through conductor motion. Corrosion in polluted environments can also be an issue particularly inside clamps

Wear damage to trunnions and straps of suspension clamps occurs due to conductor movement. The wear has been greatest in areas of constant wind, i.e. higher ground, flat open land and near coasts. For quad lines, in particular at wind exposed sites, wear can be extensive and rapid failures of straps, links, shackles and ball-ended eye links can occur. This is one of the best indicators of line sections subject to sustained levels of wind induced oscillation and hence where future conductor damage is likely to become a problem.

Most conductor joints for ACSR have been of the compression type, although bolted joints are used in jumpers. Overheating joints can arise from inadequate compression along the length of the joint, mainly due to either poor design or installation problems. These allow moisture penetration and oxidation of the internal aluminium surfaces between the joint and conductor. The resistive aluminium oxide reduces the paths for current flow and may cause micro-arcing within the joint. The consequence of this deterioration is that the joint becomes warm which further increases the rate of oxidation. Over a period of time, the resistive paths can result in excess current flowing in the steel core of the conductor, which can then overheat and rupture.

### 13.4.1.4 Deterioration of Semi-Flexible Spacers

These are fitted in the span and the semi-flexibility comes from either elastomer liners, hinges or stranded steel wire depending on the manufacturer. End of life is defined by perishing of the elastomer lining or broken/loose spacer arms. These allow for excessive movement of the conductor within the clamp leading to severe conductor damage in small periods of time (days to months, depending on the environmental input). The elastomer lining of the Andre spacer type also causes corrosion of conductor aluminium wires due to its carbon content and subsequent galvanic corrosion. A common finding of conductor samples at these positions is strands with significantly poorer tensile and torsional test results. This is a hidden condition state unless it manifests in broken conductor strands that are visible on inspection.

Replacement of these spacers has been necessary on routes that are heavily wind exposed at approximately 25 years. There are many examples still in service beyond their anticipated life of 40 years where visual end of life characteristics have not yet been met. As the condition of the associated conductor within or near the clamp can remain hidden, certain families of this type of spacer such as the 'Andre' are identified for the increased risk they pose to conductor health

### 13.4.1.5 Deterioration of Spacer Dampers

As the service history of spacer dampers is limited, extensive data on their long-term performance and end of life is not yet available. The spacer arms are mounted in the spacer body and held by elastomer bushes. This increased flexibility should provide the associated conductor system with more damping and greater resilience to wind induced energy. End of life criteria will be defined by broken/loose spacer arms that allow for excessive movement of the conductor/clamp interface.

### 13.4.1.6 Deterioration of Vibration Dampers

Stockbridge dampers have always been used for the control of AEoLian vibration, a minimum of one damper being installed at each end of every span on each sub conductor. For long spans (where specified by the manufacture) two or more may be used. End of life is defined by loss of damping capability which is visually assessed in the amount of 'droop' in and wear of the messenger cable between damper bells. The useful life of a damper is constrained by wind energy input and corrosion of the messenger wire connection with the damper bells. In areas of high wind exposure there is evidence that dampers have required replacement after 10 to 15 years. There are however many more examples of dampers operating beyond their anticipated life with no visual signs of end of life.

### 13.4.2.1 OHL Conductor EoL Modifier example 1

The formula described in the methodology for EoL is given as the following. The components and details of this formula are also described.

$$EOLmod = \begin{cases} PRE_{HS} & if\ VAL = 0 \\ SEC_{HS} & if\ VAL = 1 \end{cases}$$
$$PRE_{HS} = W_{FAM} * max(AGE_{SCORE}, REPAIR_{SCOR})$$

**Equation 54**

These conductors were installed in 1980, so were 37 years old in 2017. It is 18 years from its anticipated lifetime of 55; giving an age score of 5.

The number of repairs carried out on the circuit is 3, translating to 0.07 repairs per span. This gives the repair score of 10. A repair is considered to return the conductor to a minimum of 95% of its tensile rating. The family weighting is given by the following:

$$W_{FAM} = \frac{Average\ Sample\ Score\ within\ family}{Average\ Sample\ Score\ across\ all\ OHL\ conductor\ assets}$$

**Equation 55**

For this asset, $W_{fam}$ = 2.93.

This gives $PRE_{HS}$ = 2.93*45 = 29.3.

There is no condition assessment information for this asset, so overall EoL modifier is considered 29.3. This is in line with the asset's age and prediction of AAL.

### 13.4.2.2 OHL Conductor EoL Modifier example 2

This asset had sufficient conductor sample data to trigger the validity criteria within the EoL modifier formulation. All of the environmental categories relevant to this installation have been sampled sufficiently to qualify. This means the sample results are used in preference to age/repairs information.

Phase conductor sample scores were 54.5.

Samples for an adjacent circuit of identical installation were available, and therefore possible to apply knowledge of those samples to this circuit.

The samples with the worst scores driving the overall end of life modifier indicated the following. EoL modifier scores are given in brackets.

This circuit had significant presence of aluminium hydroxide (15), dry grease (10), steel strand damage (2.5), steel corrosion (2), aluminium strand damage (5), weak aluminium tensile strength (15) and the breaking load of the aluminium slightly poor (5). Summation of these scores gives an overall EoL modifier of 54.5.

### 13.4.2.3 OHL Conductor EoL Modifier example 3

This asset had sufficient conductor sample data to trigger the validity criteria within the EoL modifier. The phase conductor sample score was 20.

This circuit had significant presence of aluminium hydroxide (15) and a slight grease issue (5). The summation of these scores gives an overall EoL modifier of 20.

Conductor samples showed that even though there was a large amount of aluminium hydroxide present at spacer locations; testing of individual strands indicated little degradation of tensile load and torsional revolutions of the aluminium. The conductor is "core-only" greased but showed little to no degradation of the conductor itself.

The data produced by intrusive checks have allowed extension of this conductor to 2025+. Further condition assessment will track the deterioration of this asset; in order to optimally plan and time its replacement.

### 13.4.3.1 OHL Fitting EoL Modifier example 1

The formula described in the methodology for EoL is given as the following. The components and details of this formula are also described.

$$EOLmod = \max(SPA, DAM, INS, PHF)$$
**Equation 56**

The functional form of each of the components is fairly similar such as:

$$SPA = \frac{(SPA_{PRE} * LVL1) + SPA_{OvCA}}{6}$$

Where

$$SPA_{PRE}, DAM_{PRE}, INS_{PRE}, PHS_{PRE} = \begin{cases} 0 & AGE - AAL \leq -13 \\ 300 & AGE - AAL \geq -3 \\ 30(AGE - AAL) + 390 & otherwise \end{cases}$$
**Equation 57**

This circuit does not have fitting condition data. The EoL modifier is therefore driven by the preliminary score, based on age. The fittings were installed in 1977, so were 40 years old as of 2017. The AAL is 30. This gives a preliminary score of 30*(40-30)+390=690. Since the spacer, damper, insulator, and phase fittings scores are all driven by this preliminary result, the EoL modifier set is at its maximum 100 (690/6=115).

### 13.4.3.2 OHL Fitting EoL Modifier example 2

The driver on this circuit is the phase fittings assessment. Insulator, damper, and spacers were also poor. The phase fittings are assigned a score of 600, as >4.5km of the route had a sample score of 600.

It was not necessary to use age, as there was sufficient condition data to assess. The overall EoL modifier was set to 100 (600/6).

This route has a high score due to the population of specific brown porcelain insulation found on this route. The insulators used are known to have an inherent defect where they can be susceptible to cracking. Under normal operation they work as expected; but under faults conditions have potential to fail catastrophically. Multiple examples were found on this route to be cracked, driving the high EoL score.

The route has since been intervened on and at-risk insulators replaced.

# 14 Parameters for End-of-Life Scoring

The End of Life Scoring for different asset classes uses different factors depending on what failure modes can be detected and what information is available.

Examples of asset scoring are interspersed through the previous section.

## 14.1 Circuit Breakers

### 14.1.1 General method

Circuit breakers will be assigned an end of life modifier according to the formula below. The maximum of the components as shown is determined, and it is capped at 100.

$$EOLmod = \max\left(AGE_{FACT}, DUTY_{FACTOR}, SF6_{FACTOR}, DEFECT_{FACTOR}, FAMILY_{FACTOR}\right)$$

**Equation 58**

The EoL modifier is therefore determined based on the maximum of its constituent parts. AGE_FACTOR, DUTY_FACTOR, SF6_FACTOR and FAMILY_FACTOR are non-dimensional variables with possible values between 0 and 100.

$$AGE\_FACTOR = C_1 \times FSDP \times \frac{Age}{AAL}$$

**Equation 59**

- Age: Reporting year - Installation year (years)
- $C_1$: a scaling factor to convert Age to a value in the range 0 to 100. The method for calculating $C_1$ is described in section 14.1.7.
- *AAL* is the anticipated asset life determined through FMEA. The end of life curve described in the Failure Modes and Affects analysis section can be used to determine *AAL*, which is the 50% point on the respective end of life failure mode curve. The process for deriving these failure mode curves, which we use to determine AAL, are themselves estimated using historical data and engineering expertise. Further explanation is available in the section of this methodology discussing FMEA.
- FSDP is a family specific deterioration correction function described below. This is a function multiplier to convert age from a linear function to an exponential function. This has the effect of decreasing the relative significance of lower values of age.

The AAL value is determined through interpretation of historic data associated with the type and manufacturer of the circuit breaker. Other factors can also influence the AAL including locational factors such as whether the asset is indoors or outdoors. Other locational factors such as proximity to high corrosion potential are not included as these are covered through maintenance activities to ensure that the asset achieves its Anticipated Life. Note that it would require invasive work to assess the actual condition of a particular sub component.

### 14.1.2 Duty Factor

The duty of each circuit breaker asset is determined using the following formula:

$$DUTY\_FACTOR = C_1 \times FSDP \times \max\left(\left(\frac{(OC)}{(MOC)}\right), \left(\frac{(FC)}{(MFC)}\right)\right)$$

**Equation 60**

Where:

OC = the current asset operational count

MOC = the expected max asset operational count over a lifetime. For older circuit breakers this is determined through liaison with suppliers, and for newer circuit breakers this is determined during type testing

FC = the current accumulated fault current

MFC = the max permissible fault current over a lifetime. The value for MFC is set to 80% of the value of the maximum rated value for the asset

FC and MFC are determined through liaison with suppliers who confirm operational limits for the mechanism and interrupter.

Note that the DUTY_FACTOR has been normalised to account for variations in the asset life of the circuit breaker family. This normalisation means that the end of life modifier of a circuit breaker from one family can be compared to the end of life modifier of a circuit breaker from a different family. Age and other duty related metrics are important due to the lack of more specific condition information.

### 14.1.3 Family Specific Deterioration Profile (FSDP)

The Family Specific Deterioration profile accounts for the expected deterioration of an asset. This is needed as there is limited availability of Asset Specific condition information. This function is based on duty value D which is given by the following formula:

$$D = \max\left(\frac{OC}{MOC}, \frac{FC}{MFC}, \frac{AGE}{AAL}\right)$$

**Equation 61**

The family specific deterioration function is determined using the function:

$$FSDP = e^{k*D^2} - 1$$

**Equation 62**

This parameter k is determined such that when D=1.0 then *FSDP*=1.0. This gives a value of k=0.694. FSDP is capped at 1.0.

This function ensures that the impact of family specific deterioration is correctly considered in the health score formula.
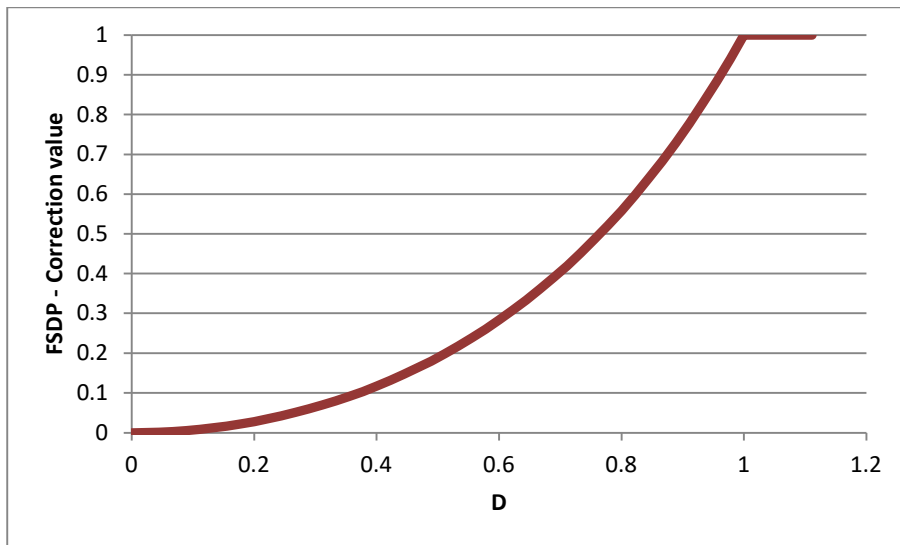


**Figure 24**

The curve will generate a value from 0 to 1 depending on the duty of the asset. This curve is used within this method due to the lack of condition information and allows us to accelerate or suppress duty values depending on the deterioration we would expect for that asset family. Note that while the shape of the curve is fixed, the duty value (D) captures family specific factors such as anticipated asset life, maximum fault current and maximum number of operations.

### 14.1.4 SF6 Factor

The SF6_FACTOR calculation maps the reported leakage of a circuit breaker to a score of between either 0 or 100. A score of 100 is assigned where major leakage is deemed to have occurred. Leaking time is the time in years that the asset has had a non-zero Leak $_{mass}$, Leak $_{rate,}$ or Leak $_{combined}$.

$$SF6_{FACTOR} = Max(Leak_{Mass}, Leak_{Rate}, Leak_{Combined}) + Leak_{Duration} * Leaking_{time}$$
**Equation 63**

Leak$_{mass}$ is a score dependent on the mass of SF6 leakage (kg) within the previous financial year.

| Mass of Leakage (kg) | Significance | Leak$_{mass}$ Score |
|---|---|---|
| <10kg | Insignificant | 0 |
| >=10kg | Significant | 60 |
| >=50kg | Major Leakage | 75 |

**Table 21**

Leak$_{rate}$ a score dependent on proportion of total installed mass of SF6 that has leaked within the previous financial year

$$Leakage\ rate = \frac{Leak_{Mass}}{Asset\ SF6\ Inventory}$$
**Equation 64**

where Asset SF6 Inventory is the Reported volume of SF6.

| Mass of Leakage (kg) | Significance | Leak$_{rate}$ Score |
|---|---|---|
| <5% | Insignificant | 0 |
| >=5% | Significant | 60 |
| >=10% | Major Leakage | 75 |

**Table 22**

Leak$_{combined}$=100 if both the mass of leakage is >=50kg and leakage rate is >=10%, otherwise Leak$_{combined}$=0

Leak$_{duration}$ ensures that a leaking asset for the last two or five (dependant on current severity of leak) years will be assigned a score of 100.

$$Y = Max(Leak_{Mass}, Leak_{Rate}, Leak_{Combined})$$
**Equation 65**

| Leakage Duration | Leak$_{duration}$ Score |
|---|---|
| First year of leak | 0 |
| $Y$ =60 | 8 |
| $Y$ =75 | 12.5 |

**Table 23**

Any asset classified with EoL modifier of 60 or 75 due to SF6 leakage will undergo a significant intervention within a 5 year or 2 year timeframe respectively. It is expected that an asset classified with a health score of 75 today will reach a health score of 100 within 2 years, which has been set-up to reflect legislation that significant SF6 leakers should be repaired within 2 years. The decision over which type of intervention to carry out, *whether that is repair, reconditioning, refurbishment, or replacement*, will be *cost justified* for the expected benefit to the consumer. This means that risk will be reduced through the most cost justified intervention, which may not necessarily be asset replacement.

Whilst there are pre-existing technologies that exist to carry out minor repairs to stop SF6 leaks, analysis of these repairs demonstrates that usually they are temporary in nature and a further major intervention is then required to permanently repair the asset.

Broadly there are two functional requirements for a Gas Circuit Breaker. Firstly, it must be able to break load, and secondly it must be able to retain the Insulating Medium. This is based on the requirements described in the Fluorinated Greenhouse Gases Regulations 2015, which places significant limits on permitted Leakage.

1. Operators of equipment that contains fluorinated greenhouse gases shall take precautions to prevent the unintentional release ('leakage') of those gases. They shall take all measures which are technically and economically feasible to minimise leakage of fluorinated greenhouse gases.
2. Where a leakage of fluorinated greenhouse gases is detected, the operators shall ensure that the equipment is repaired without undue delay. (Checking F gas equipment for leaks - GOV.UK (www.gov.uk))

### 14.1.5 Defect Factor
This factor is currently set to zero awaiting improved classification in data collection process

### 14.1.6 Family Factor
Circuit breaker families that are exhibiting life limiting factors, which do not align to the other factors in the formulation, needs to be captured by the end of life modifier scoring process. As such a factor will be applied to drive intervention due to end of life to be approximately within a specific timeframe.

| Asset family modifier | Score |
|---|---|
| Intervention within 2 years | 80 |
| Intervention within 5 years | 60 |
| Intervention within 10 years | 35 |

**Table 24**

### 14.1.7 Procedure for Determining C1
This value of this parameter is determined by calculating a value for EoL modifier from historical switchgear data. The C1 value was initially tuned to give a reasonable translation between historical AHI's, which were calculated under the previous RIIO-T1 volume-based methodology, and EoL modifier. Assets that classed as AHI1 previously would be expected to have a score of 100 under the new methodology.

The scaling factors were further refined during the calibration, testing and validation exercise.

Based on this approach the parameter is fixed as $C1 = 80$

## 14.1.8 EoL Modifier Calculation Example

The following table shows three assets with example data that will allow us to determine the EoL modifier

| Component | Example Asset 1 | Example Asset 2 | Example Asset 3 |
|---|---|---|---|
| Asset Operation Count (*OC*) | 350 | 3000 | 350 |
| Max Asset Operation Count (*MOC*) | 5000 | 5000 | 5000 |
| Accumulated Fault Current (*FC*) | 400 | 400 | 1000 |
| Max Permissible Fault Current (*MFC*) | 1400 | 1400 | 1400 |
| Anticipated Asset Life (*AAL*) | 45 | 45 | 45 |
| SF6 leakage (kg) | 2 | 10 | 1 |
| Age | 40 | 20 | 15 |

**Table 25**

Applying the relevant formula presented in the above sections yields the following output.

| | Example Asset 1 | Example Asset 2 | Example Asset 3 |
|---|---|---|---|
| **D (in FSDP)** | 0.89 | 0.6 | 0.71 |
| **FSDP** | 0.72 | 0.28 | 0.41 |
| **AGE_FACTOR** | 53.19 | 10.23 | 11.23 |
| **DUTY_FACTOR** | 16.73 | 13.94 | 24.16 |
| **SF6_FACTOR** | 0 | 60 | 0 |
| **EoL Modifier** | 53.2 | 60 | 24.2 |

**Table 26**

The EoL Modifier in example asset 1 is driven by age factor, example 2 is driven by SF6 factor and example 3 is driven by the duty factor (the accumulated fault current).

The EoL modifier calculation proposed here facilitates a reasonable translation from the AHI's utilised within the original RIIO-T1 methodology. Validation has been performed to calculate EoL modifier over a range of assets and then comparing to the AHI determined under the existing methodology.

It should be noted that placing a cap on the age related components of health score would substantially impair the translation from the previous AHI to health score.

## 14.2 Transformers and Reactors
## 14.2.1 General method

The scoring process needs to take account of the four failure modes – dielectric, mechanical and thermal as well as issues with other components that may significantly impact the remaining service life. The end of life modifier is determined according to the following formula:

$$EOLmod = \left(1 - \left(1 - \frac{DCF}{100}\right)\left(1 - \frac{TCF}{100}\right)\left(1 - \frac{MCF}{100}\right)\left(1 - \frac{OCF}{100}\right)\right) * 100$$

**Equation 66**

The components of the end of life modifier are assigned using the scoring system described below. The component OCF (other component factor) is a factor that accounts for other issues that can affect transformer end of life. The maximum value of *EoLmod* is 100.

As far as possible National Grid uses actual condition indicators rather than extrapolating condition from load and temperature over time. This approach is more feasible with large transformers and is less dependent on the availability of historical data. The approaches are not mutually exclusive and loading data is important to the correct interpretation of some condition indicators such as oil test results

## 14.2.2 Dielectric Condition Factor (DCF)

Dielectric condition is assessed using dissolved gas analysis (DGA) results. The score can be increased if the indication is that the individual transformer is following a trend to failure already seen in other members of the family. Where it is known that the indications of partial discharge are coming from a fault that will not ultimately lead to failure, e.g. a loose magnetic shield, then the score may be moderated to reflect this, but the possibility of this masking other faults also needs to be considered.

| Score | Dielectric Condition Criteria |
|---|---|
| 0 | All test results normal: no trace of acetylene; normal levels of other gases and no indication of problems from electrical tests. |
| 2 | Small trace of acetylene in main tank DGA or stray gassing as an artefact of oil type, processing, or additives. Not thought to be an indication of a problem. |
| 10 | Dormant, intermittent, or low level arcing/sparking or partial discharge fault in main tank. |
| 35 | Steady arcing/sparking or partial discharge fault in main tank. or A fault where corrective actions have arrested symptoms of the fault, but it may reoccur. |
| 85 | Indications that arcing/sparking fault is getting worse. |
| 100 | Severe arcing/sparking or partial discharge fault in main tank – likely to lead to imminent failure. |

**Table 27**

## 14.2.2 Thermal Condition Factor (TCF)

Thermal condition is assessed using trends in DGA and levels of furans in oil. Individual Furfural concentration (FFA) results are unreliable because they can be influenced by temperature, contamination, moisture content and oil top ups, therefore a trend needs to be established over a period of time. The presence of 2 Furfural (2FAL) is usually required to validate the FFA result, and the presence or absence of methanol is now being used to validate (or otherwise) conclusions on thermal score. Thermal condition is understood to include ageing and older, more heavily used and/or poorly cooled transformers tend to have higher scores. The score can be increased if the indication is that the individual transformer is following a trend to failure already seen in other members of the family.

| Score | Thermal Condition Criteria |
|---|---|
| 0 | No signs of paper ageing including no credible furans ≥0.10ppm and methanol ≤0.05ppm. |
| 2 | Diagnostic markers exist that could indicate paper ageing (including credible furans in the range 0.10-0.50ppm) or are thought to be the result of contamination. |
| 10 | Indications or expectations that the transformer is reaching or has reached mid-life **for example**: credible furans in the range 0.51-1.00ppm or stable furans >1ppm possibly as a result of historic paper ageing.<br><br>and/or<br><br>DGA consistent with low temperature overheating e.g. raised levels of methane or ethane in the main tank.<br><br>and/or<br><br>Transformers with diagnostic markers resulting from oil contamination (e.g. furans, specifically 2FAL) that may mask signs of paper ageing. |
| 35 | Moderate paper ageing **for example**: credible furans consistently > 1ppm with a clear upward trend.<br><br>and/or<br><br>Significant overheating fault e.g. steadily rising trend of ethylene in main tank DGA. |
| 85 | Transformer is aged and believed to be within the final quarter of its life which may be evidenced by advanced paper ageing, **for example**:<br>• Credible furans > 1.5ppm showing a clear upward trend (even if the furan level has subsequently stabilised) or where the paper could be expected to be aged (DP:~250) based on indications from a previously scrapped sister unit which may be supported by the presence of methanol<br><br>and/or<br><br>Significant and worsening overheating fault. |
| 90 | Transformer is believed to be within 5-10 years of its end of life which may be evidenced by very advanced paper ageing, **for example**:<br>• Credible furans ~2.0ppm showing a clear upward trend (even if the furan level has subsequently stabilised) or where the paper could be expected to be significantly aged (DP:~240) based on indications from a previously scrapped sister unit<br>• Or similarly credible furans ~1.5ppm in a transformer with <40 service years (indicating premature ageing)<br>• Indications of methanol<br><br>and/or<br><br>Significant and worsening overheating fault. |
| 95 | Transformer is believed to be within 5 years of its end of life which may be evidenced by severe paper ageing, **for example**:<br>• Credible furans > 2ppm showing a clear upward trend (even if the furan level has subsequently stabilised) or where the paper could be expected to be severely aged (DP:~220) based on indications from a previously scrapped sister unit.<br>• Indications of methanol.<br><br>and/or<br><br>Significant and worsening overheating fault. |
| 100 | Paper aged to end of life, **for example**: credible furans >2.25ppm with an upward trend or where a sister unit was found to be at end of life (DP<200) with similar indications when scrapped.<br><br>and/or<br><br>Serious overheating fault. |

*Table 28*

Electrical test data may be used to support a higher thermal score where they show poor insulation condition. Electrical tests can provide further evidence to support the asset management plan for individual transformers e.g. where a significant number of oil tops ups have been required for a particularly leaky transformer and it is suspected that this is diluting the detectable Furans in the oil. However experience shows that not all poor thermal conditions can be detected by electrical tests which is why DGA data remains the focus for scoring the Thermal Condition Factor.

While age and AAL are not explicitly considered as part of the transformer EoL modifier scoring process, the thermal condition score is a fairly good indicator of the age of an asset. The DGA results obtained from oil samples will generally show signs indicating the aging of a transformer including increased levels of furans.

## 14.2.3 Mechanical Condition Factor (MCF)

Mechanical condition is assessed using Frequency Response Analysis (FRA) results.

| Score | Mechanical Condition Criteria |
|-------|-------------------------------|
| 0 | No known problems following testing. |
| 1 | No information available. |
| 3 | Anomalous FRA results at last measurement which are suspected to be a measurement problem and not an indication of mechanical damage.<br>and/or<br>Corrected loose clamping which may reoccur. |
| 10 | Loose clamping<br>or<br>Following the indications of a sister unit found to have had compromised mechanical integrity/short circuit strength<br>or<br>A design known to have a poor short circuit design. |
| 35 | Suspected mechanical damage to windings. This does not include cases where the damage is confirmed. |
| 85 | Loose or damaged clamping likely to undermine the short circuit withstand strength of the transformer. |
| 100 | Confirmed mechanical damage to windings. |

Table 29

Mechanical condition is assessed using Frequency Response Analysis (FRA) results; FRA is used to detect movement in the windings of the transformer, these data are supplemented by family history e.g. where post mortem analysis of a similar transformer has confirmed winding movement and DGA results (which indicate gas generation from loose clamping) as appropriate.

## 14.2.4 Other Condition Factor (OCF)

The Other Components score uses an assessment of other aspects; this includes:

- Tap-changers. Tap-changers are maintained and repaired separately to the transformer and defects are most likely repairable therefore tap-changer condition does not normally contribute to the AHI score. Where there is a serious defect in the tap-changer, and it cannot be economically repaired or replaced this will be captured here.
- Oil Leaks. During the condition assessment process transformers may be found to be in a poor external condition (e.g. severe oil leaks), this will be noted, and the defect dealt with as part of the Asset Health process. The severity of oil leaks can be verified by oil top up data. Where there is a serious defect and it cannot be economically repaired, this will be captured here.

Other conditions such as tank corrosion, excessive vibration that cannot be economically repaired and audible noise which has resulted in complaints from stakeholders will be captured here.

| Score | Other Component Criteria |
|---|---|
| 0 | No known problems/minor or infrequent oil leaks. |
| 2 | Oil leaks (in excess of 2000 litres per annum over the past 3 years) that **can** be economically repaired but the volume of top ups may be diluting diagnostic gases. |
| 10 | Oil leaks (in excess of 2000 litres per annum over the past 3 years) that cannot be economically repaired.<br><br>and/or<br><br>Tap-changer that is known to be obsolete and spare parts are difficult to acquire or that is heavily used(average operations >6500 p.a.)/incurs high maintenance costs. Or, based on historic failure data, the tap-changer is known to have a higher risk of failure. |
| 35 | Exceptional oil leaks (on a rolling basis, generally in excess of 10 000 litres per annum over the past 3 years) that cannot be economically repaired where the annual oil top up volume is likely to be diluting diagnostic markers.<br><br>and/or<br><br>Other mechanical aspects potentially affecting operation that cannot be economically repaired for example: tank corrosion, excessive vibration.or<br><br>Justifiable noise complaint for which there may be a practicable means of mitigation. |
| 85 | Exceptional oil leaks (on a rolling basis, generally in excess of 15 000 litres per annum over the past 3 years) that cannot be economically repaired and where the effectiveness of the secondary oil containment system is in doubt and would be difficult or impossible to repair without removing the transformer.<br><br>and/or<br><br>Tap-changer that is known to be in poor condition and obsolete with no spare parts available.<br><br>or<br><br>Justifiable noise complaint for which there is no practicable means of mitigation, where empirical data supports the noise complaint and there is a strong indication that a noise abatement notice could be served. |
| 100 | Confirmed serious defect in the tap-changer that cannot be economically repaired or replaced.<br><br>or<br><br>Audible noise complaint which has resulted in a noise abatement notice, for which there is no practicable means of mitigation. |

Table 30

Where noise mitigation measures are planned the Other Component Score may be subject to review, for instance where efficiencies can be delivered by bringing forward a planned replacement and negating the need to take mitigating actions.

Oil quality is assessed using the results of four tests – acidity, interfacial tension, dissipation factor and resistivity. The oil quality score does not contribute to the AHI score, but it is used to prioritise transformers requiring oil replacement or regeneration.

### 14.2.5 Family Specific Considerations

Where individual test results, trends in test results or family history give cause for concern, specialist diagnostics are scheduled as part of a detailed condition assessment. Where appropriate, continuous monitoring will also be used to determine or manage the condition of the transformer. The EoL modifier scoring process will then be applied as described above, which can lead to an increase in the score applied to an asset.

Thermal condition is assessed using trends in DGA and levels of furans in oil, supplemented by family and operational history and electrical test data as appropriate. The score can be increased if the indication is that the individual transformer is following a trend to failure already seen in other members of the family. Following the scrapping of a transformer it may be necessary to review the thermal scores assigned to remaining sisters in a family.

Note that transformers share the same end of life failure mode group. Reactors are split into two end of life failure mode groups. A failure mode group has specific parameters for earliest and latest onset of failure ages. The process for deriving these failure mode curves, are themselves estimated using historical data and expert opinion. Further explanation is available in the section of this methodology discussing FMEA.

### 14.3 Cables
### 14.3.1 General method

The formula to determine the EoL modifier for cables, which is capped at a maximum of 100, is:

$$EOLmod = ACS + Sub\_ADJ$$

**Equation 67**

Where ACS is the main asset condition score and Sub_Adj is the sub-asset condition score adjustment.

$$ACS = (AALc * GFR) + DUTY + CYCLING + \max(DEFECTS, SEVERITY) + ACCESS + \max(OIL, PROIL) + Main\_ADJ$$

**Equation 68**

The factors defined in this formula are described as listed below.

### 14.3.2 Current Age Variation from Anticipated Asset Life (AALC)

In the table below variation= age – anticipated asset life. The anticipated asset life is listed in the appendix section and reflects specific issues associated with a particular family.

| Variation from anticipated asset life (AALC) | |
|---|---|
| >=Variation | Score |
| -100 | 0 |
| -5 | 2 |
| 0 | 5 |
| 5 | 20 |
| 10 | 25 |
| 15 | 30 |

**Table 31**

### 14.3.3 Generic Family Reliability (GFR)

This component is used to score any known generic family issues which can affect the anticipated life of the asset, that is, a design weakness may become apparent for a particular family of assets. For example, it has been determined that type 3 cables have a known generic defect. Type 3 cables are AEI and pre-1973 BICC oil filled cables with lead sheath and polyvinyl chloride (PVC) over sheath and an additional risk of tape corrosion or sheath failure. This scoring takes account of the family design issues which are a risk to the anticipated asset life.

| Generic Family Reliability (*GFR*) | |
|---|---|
| | **Weighting** |
| **Evidence of design issue** | 3 |
| **Vulnerable to design issue** | 2 |
| **Vulnerability to design issue mitigated** | 1.5 |
| **Other** | 1 |

**Table 32**

### 14.3.4 Duty & Cycling

Operational stresses on a cable have the potential to contribute to the occurrence of defects and impact useful service lifetime. Two parameters are evaluated at this time. It should be noted that further refinement of these parameters are under consideration; the material included at this time is representative of the thinking and discussions following Ofgem's Supplementary Questions throughout 2020.

The Duty parameter accounts for operational stress as a result of accumulated operation at very high loads. It is measured in terms of the hours the cable has operated at or above its maximum designed continuous rating during the last 5 years.

The meshed nature of the England and Wales transmission network is such that this factor is typically zero; though there are certain circumstances where a cable may have to operate at higher loads frequently (e.g. on-load switching) or, in response to a fault of extended duration. Scoring in this category is tested by exception where the TO has cause to investigate the operational history of a cable.

| Duty – hours at or above max rating (*DUTY*) | |
|---|---|
| >= Hours | Score |
| 0 | 0 |
| 24 | 5 |
| 48 | 10 |
| 120 | 15 |

**Table 33**

AC Cables undergo significant thermomechanical forces as a result of changes in load, expanding and contracting with temperature. There is also evidence[10] that repeated or frequent switching activities are factors in the deterioration of cable insulation and bonding & earthing components. These factors are elevated where items are frequently switched within a 24-hr period, due to the combination of trapped charge plus energisation current. This type of action is commonly carried out for purposes of reactive power compensation or voltage control by the ESO; or in association with specific generator circuits known to repeatedly load and unload to high proportions of their capability.

A minority of circuits have been identified where their condition is known to have been influenced by these activities. Where this is the case, the EoL modifier is adjusted by a further 10 points. While the impact of this adjustment varies by asset family and chronological age (due to the non-linear deterioration curves); for the purposes of an example, a 40-year old XLPE cable in otherwise perfect condition (i.e. EoL = 0) would have a PoF of 0.023 before this adjustment, and 0.033 afterwards. The adjustment is intended to be proportional to the accelerated deterioration.

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[10] Analysis of Long Electrical Sections (ALECS) deliverable 2; S. Sutton, University of Southampton, 2016.

### 14.3.5 Defects

This represents the total number of faults and defects raised against each asset over the last 10 complete financial years.

| Number of Defects (DEFECTS) | |
| --- | --- |
| >= Number of Defects | Score |
| 0 | 0 |
| 10 | 15 |
| 40 | 35 |
| 90 | 40 |

Table 34

### 14.3.6 Severity

The severity of repairs to remedy faults and defects is quantified by the man-hours spent carrying out these repairs.

| Repair Time in Hours (SEVERITY) | |
|---|---|
| >= Time | Score |
| 0 | 0 |
| 500 | 5 |
| 950 | 20 |
| 1500 | 30 |
| 2350 | 40 |

**Table 35**

### 14.3.7 Days not available over last year period April/April (Access)

This score is determined from the total number of days out of service based on outages in the last financial year.

| Access (*ACCESS*) | |
|---|---|
| >= Days | Score |
| 0 | 0 |
| 50 | 2 |
| 100 | 5 |
| 200 | 10 |
| 300 | 20 |

**Table 36**

### 14.3.8 Historical Oil leaks in Last 10 Years (Oil)

This is the litres of oil leaked in the last 10 years.

| Oil leaks last ten years (*OIL*) | |
|---|---|
| >= Litres | Score |
| 0 | 0 |
| 1000 | 5 |
| 1500 | 10 |
| 2000 | 15 |

**Table 37**

### 14.3.9 Pro-Rate to 1km Oil Leaks in Last 10 Years (PROIL)

This is the pro-rata to 1km litres of oil leaked in the last 10 years. This is quantity of oil lost over the last 10 years divided by the length of the cable.

It is important to include pro-rata oil leaks, so that significant oil leaks from short cables are not missed due their relatively low volume compared to significant oil leaks from long cables.

| Oil leaks last ten years (*PROIL*) | |
|---|---|
| >= Litres | Score |
| 0 | 0 |
| 200 | 5 |
| 400 | 10 |
| 500 | 15 |

**Table 38**

### 14.3.10 Main Cable Information (MAIN_ADJ)

The following condition scores will be applied when determining a cable EoL score. These factors tend to be bespoke to each cable route, so need to be included in the calculation as an adjustment component.

- Known presence of tape corrosion. (Score 10). Extensive research has been completed on the risk associated with corrosion of bronze-reinforcing tapes on certain makes and models of SCOF cables. Where these risks are not only a threat, but there is active evidence of failures of this nature (typically by cutting damaged sections from the cable, confirming the suspicions that they were at risk), this adjustment is applied.
- Oversheath material issues. (Score 10). The technical specifications for cable oversheath are relatively flexible and give manufacturers a broad range of options to solve the oversheath requirement. Hard oversheath is more resistant to water but can be vulnerable to fracturing; whereas a soft oversheath less resistant to water but more resilient to movement. Abrasion is a risk to any oversheath. Where a circuit is identified as having problems arising from these materials, the score is adjusted to reflect their presence.

### 14.3.11 Sub-asset Information (SUB_ADJ)

The cable has a number of sub-asset upon which it is reliant for operation. These sub-assets also experience deterioration.

- Risk of failure of old style link boxes. (Score 5)
- Risk of stop joint failure. (Score 5)
- Risk of sheath voltage limiter (SVL) failure. (Score 5)
- Poor Condition of joint plumbs. Information about whether they have been reinforced. (Score 5)
- Known faults with oil tanks, oil lines, pressure gauges and alarms. (Score 5)
- Condition or faults with cooling system (if present). (Score 5)
- Occurrence of sheath fault (5) Multiple faults (10)
- Known issues with the cable's laying environment (Score 5 or 10, by severity). Certain cable installations have a history of problems arising from their laying environment, for example tunnel & trough flooding risks leading to damage or difficulties in completing maintenance; abrasion & sharps in the backfill. Where cause for concern is identified; this parameter is scored 5. Where there is positive confirmation the laying environment is contributing to risk, this is scored 10.
- Threat, or known occurrence of subsidence (Score 0-35, by severity). Threats to cables and/or associated installations (such as cable bridges) have been identified with geophysical or civil engineering issues leading to subsidence. The subsidence risk is predominantly associated with cables installed in railway embankments. A replacement is not necessarily the optimal intervention in this situation, though these are evaluated as part of the EoL scoring in the interests of prioritising the necessary intervention. Scores are assigned in accordance with the table below reflecting the immediacy and extent of threat and/or where issues have positively been identified as responsible for defects.

| Subsidence | |
|---|---|
| *Severity of subsidence* | *Score* |
| *No subsidence evident* | *0* |
| *Potential Subsidence identified, investigation triggered, potential distress to cable* | *10* |
| *Investigation confirms subsidence has occurred, defects found* | *20* |
| *Monitoring confirms subsidence is continuing, defects worsening* | *35* |

Table 39

## 14.4 Overhead Line Conductor Parameters
## 14.4.1 General method

Overhead Line Conductors are assigned an end of life modifier using a 2-stage calculation process. The first stage assesses each circuit section based on conductor type, time in operating environment and number of repairs. The second stage assesses information gathered from condition assessments. The overall end of life modifier is given by:

$$EOLmod = \begin{cases} PRE_{HS} & if\ VAL = 0 \\ SEC_{HS} & if\ VAL = 1 \end{cases}$$

**Equation 69**

Where:
$PRE_{HS}$ is a 'Preliminary' or 'First Stage' score and
$SEC_{HS}$ is a 'Secondary Stage' Score.

The maximum preliminary value of *EoLmod* is 60. In this case, a modifier of 60 equates to an asset being a state requiring replacement i.e. a probability of failure of ~10% per year.

The preliminary health score PRE$_{HS}$ is effectively capped at 40, which ensures that an asset is never replaced on the basis of only age and repair information alone. If we believe an asset to be in a worst condition than PRE$_{HS}$ indicates then additional sampling would need to be performed on that asset.

The EoL modifier methodology in this section has been developed assuming an ideal situation where all data is available. However, the methodology has been carefully designed to cope with situations where there are large gaps in or data, such that a meaningful score can still be generated.

## 14.4.2 Preliminary Stage

Each conductor is assigned to a 'family' which has an associated asset life. For ACSR conductors, this is based on:

   a. Grease Type (Fully or Core-only greased). This can be derived from installation records and sampling of the conductor. This record is stored in our Ellipse Asset Inventory.
   b. Conductor Type (e.g. Zebra or Lynx). This can be derived from installation records and sampling of the conductor. This record is stored in our Ellipse Asset Inventory.
   c. Environment Category (A – 'Heavy Pollution', B – 'Some Pollution', C – 'No Pollution', d – 'Wind Exposed'. Sections may pass through different environments so the most onerous category experienced is assigned. This is based on mapping data and employs distance to the coast and polluting sources. Wind Exposed environments generally refer to heights above sea level of 150m (where high amplitude, low frequency 'conductor galloping' is more prevalent) as well as areas where wind induced oscillations have been observed by field staff.

AAAC/ACAR conductors are one family and have one asset life.

HTLS conductors are one family and have one asset life.

The preliminary end of life modifier is taken to be the maximum of an age based score and repair based score. If the repairs component of the equation is high it always requires further investigation, regardless of the age of the asset. The spread of repair locations is also significant. Clusters may appear on spans/ sections with local environment characteristics (e.g. turbulence level). For example, the damping or configuration of the conductor bundle may require intervention to prevent earlier failure of this part of the line.

Because the processes of corrosion, wear and fatigue reduce wire cross section and strength over time, 'Age' of a line in its respective operating environment is a significant part of the conductor assessment. Factors such as distance from the coast, altitude and corrosion from industrial pollution are taken into account in the process of determining AAL for each family of OHL conductor.

Our ability to detect all the condition states of a conductor is limited. This is a composite, linear asset where condition states remain hidden without intrusive analysis. The act of taking a sample is time consuming (average 3-4 days per line gang), can only be done in places where conductor can be lowered to the ground and introduces more risk to the system by the insertion of joints between new and old conductor. This means that a preliminary health score is needed to enable scores to be determined for assets that don't have sample data. This preliminary health score is necessarily based on factors such as family weighting, age, and repairs, as these are the only sets of data known for all our OHL conductor assets. The preliminary health score is capped at 40.

$$PRE_{HS} = W_{FAM} * \max(AGE_{SCORE}, REPAIR_{SCORE}) + JNT$$

$$AGE_{SCORE} = \begin{cases} 0 & AGE - AAL \leq -8 \text{ or } AGE \leq 5 \\ 35 & -8 < AGE - AAL \leq 0 \\ 2(AGE - AAL) + 35 & otherwise \end{cases}$$

$$REPAIR_{SCORE} = REP * 100$$

**Equation 70**

Where
*REP*= Number of conductor repairs in the span being assessed divided by the total number of spans on the route or section.
AGE=Reporting year – Installed year
AAL=Anticipated asset life of the family. This is obtained from the end of life FMEA end of curve for the family. Please see the failure modes section for a general explanation of how these curves are determined and what distribution is used.

Repairs range from a helical wrap of aluminium to a compression sleeve to the installation of new pieces of conductor (requiring joints) depending on damage severity. Within any given span, the most common areas of conductor repair on our network are at or adjacent to clamping positions, in particular spacers. On routes where the number of repairs is high, exposure to wind induced conductor motion is the common characteristic. This measure is an indication of the environmental input to a line, in particular wind exposure. It does not provide a complete picture, especially for latent processes of corrosion within a conductor and fretting fatigue that has not yet manifested in broken strands.

JNT is the Joint score, which is generated from a combination of joint type and the number of location of high resistance or 'hot' joints detected in the annual infra-red camera surveys. Higher scores are generated by 'Tate/Noral' or oval type compression joints of the main 'within span' conductor at tension towers. Low scores are generated by higher resistance witnessed in bolted joints of jumper conductors. These items provide a continuous conductor path between the within-span conductors at tension towers. A multiplier is assigned for OHL 'Tate' joints to reflect that this type of joint is inferior to a hexagonal compression. If 'Tate' joints are present then TATE=2, otherwise 1.

| Infra Red Survey | JNT Score |
|---|---|
| Hot Joints in Main Compression >2.5% of Tension Towers in last 5 years | 10 |
| Hot Joints in Compressed Jumper Palm >2.5% of Tension Towers in last 5 years | 7.5 |
| Hot Joints in Bolted Jumper Palm >2.5% of Tension Towers in last 5 years | 5 |

**Table 40**

$W_{FAM}$ is a family weighting score derived from OHL conductor sample data. The sample data is calculated according to the formula $S_i$ in the following section. $W_{FAM}$ ensures that the $PRE_{HS}$ is a reasonable proxy for asset condition given the lack of actual sample data. $W_{FAM}$ is capped inside a range from 1.0 to 2.0 to prevent $PRE_{HS}$ from becoming too dominant. This means $PRE_{HS}$ is effectively capped at 40.

$$W_{FAM} = \frac{Average\ Sample\ Scores\ within\ family}{Average\ Sample\ Score\ across\ all\ OHL\ conductor\ assets}$$
**Equation 71**

### 14.4.3 Validity Multiplier

To aim for condition data that is indicative of the whole circuit or section being assessed, a validity criterion is applied. All environment categories the circuit passes through must be assessed and at least one conductor sample per 50km is required.

Results of the secondary health score are only considered if the criterion for a 'valid' set of condition assessments is met. Note that a zero value of VAL implies that there is not enough condition information and therefore the preliminary health score will be used.

The condition assessment must be no greater than 10 years old, to be valid.

For example, Route 'X' is comprised of two circuits of the same installation date and conductor type. It is 60km in length and runs through three distinct, environment classifications (Heavy Pollution 'A', Some Pollution 'B' and Wind Exposed 'D'). Three samples from the last ten years are required to meet the 'validity criteria'. The condition assessment applies to both circuits as they are of the same installation date and conductor type.

$$VAL = Criteria\ A * Criteria\ B$$
**Equation 72**

| Validity Criteria A | Criteria A value |
|---|---|
| No. of Categories Assessed / No. of Environment Categories= 1 | 1 |
| No. of Categories Assessed / No. of Environment Categories <1 | 0 |
| **Validity Criteria B** | *Criteria B value* |
| No. of samples per 50 route km >=0.02 | 1 |
| No. of samples per 50 route km <0.02 | 0 |

**Table 41**

### 14.4.4 Second Stage

On completion of the preliminary scoring, further condition indications will be reviewed to allow a second stage assessment of a conductor.

$$S_i = AH + VA + GL + DSS + GT + CL + DAS + TBL + TT$$
$$PCSI = \max\nolimits_{All\ phase\ conductor\ samples} (S_1, S_2, S_3 \ldots S_n )$$
$$SEC_{HS} = max(PCSI, COR) + JNT$$

**Equation 73**

Where
AH = Presence of Aluminium Hydroxide
VA = Visual assessment of steel core galvanising
GL = Grease level and quality
DSS = Diameter of steel strands
GT = Measurement of galvanising thickness on outer and inner face of steel core wire
CL = Measurement of corrosion later of outer and inner face of aluminium strands
DAS = Diameter of aluminium strands
TBL = Average tensile breaking load of outer aluminium strands
TT = Torsion test (average revolutions to failure of aluminium strands)

The secondary score is the maximum of the Phase Conductor Sample Index (PCSI) and Corrosion Survey (COR) inputs. A factor for conductor joints is added to this score.

The PCSI is a score between 0-100 that is generated from a set of measurements and visual observations made from a conductor sample. Conductor samples (usually about 1m in length) should focus on areas in and around clamps where the worst deterioration is expected. To obtain, the conductor is typically lowered to ground so that a piece can be removed, and a new piece inserted via a new compression joint(s). Techniques are being developed to remove a piece of conductor without lowering the whole span to ground. The condition assessment factors are broken down into:

- Visual assessment (Presence of corrosion products, quality of grease, general galvanising coverage)
- Metallographic (Measurement of strand diameter, corrosion layers and galvanising thickness)
- Mechanical (Measurement of tensile breaking load and number of revolutions to strand failure – torsion performance)

The overall PCSI score is generated from a weighted average of the max conductor sample score and the average of all conductor sample scores.

The Corrosion (Cor) input is based on the results of a zinc corrosion detection machine. This is only applicable to ACSR conductors with a steel core. The device is mounted on the conductor, with spacer clamps removed, and the whole span is surveyed. Because of the length of time taken, more than one span or more than one conductor in the span can be surveyed in the same time it takes to obtain a conductor sample. However, the survey only provides an indication of the galvanising condition.

The joint score is generated from a combination of joint type and the number of, and location of high resistance or 'hot' joints detected in the annual infra-red camera surveys. Higher scores are generated by 'Tate/Noral' or oval type compression joints of the main 'within-span' conductor at tension towers. Lower scores are generated by high resistance witnessed in bolted joints of jumper conductors. These items provide a continuous conductor path between the within-span conductors at tension towers.

Condition assessment observations adjust the view of the current Probability of Failure of an asset and inform the timing of further intervention relative to the population. As more condition data is captured, the behaviour of the wider population is also observed, and the timing of population-level risk rises can also be adjusted.

| Phase Conductor Sampling Interpretation (out of 100) | $AH + VA + GL + DSS + GT + CL + DAS + TBL + TT$ |
|---|---|
| **Presence of Aluminium Hydroxide (a corrosion product) (*AH*) (0-15)** | |
| Significant – Area/Areas with full surface coverage of powder. | 15 |
| Present – Area/Areas with small clusters of powder or a small number of particles scattered over surface | 10 |
| None | 0 |
| **Visual Assessment of Steel Core Galvanising (*VA*) (0-15)** | |
| Loss – 10% + galvanising is missing/damaged | 15 |
| Small Loss – small areas of (no more that 10% of damaged/ missing galvanising | 10 |
| Good – Galvanising appears intact | 0 |
| **Grease Level and Quality (*GL*) (0-10)** | |
| Core Only Greased Dry | 10 |
| Core Only Greased Flexible | 7.5 |
| Fully Greased Dry | 2.5 |
| Fully Greased Flexible | 0 |
| **Diameter of Steel Strands (*DSS*) (0-5)** | |
| Below the min specification of 3.18mm | 5 |
| Between 0% and 0.4% (inclusive) above min specification of 3.18mm | 2.5 |
| Greater than 0.4% above min specification of 3.18mm | 0 |
| **Measurement of Galvanising Thickness on Outer and Inner Face of Steel Core Wire (*GT*) (0-5)** | |
| Aluminium loss to steel core/evidence of rust | Score of 80 applied to COR factor |
| Average <5 microns | Score of 50 applied to COR factor |
| Average <20 microns | 5 – Score of 30 applied to COR factor |
| Average >=20 microns | 2 |
| Average >=49 microns | 0 |
| **Measurement of Corrosion Layer of Outer and Inner Face of Aluminium Strands (*CL*) (0-5)** | |
| Average >=275 | 5 |
| Average >100 | 2 |
| Average >0 | 0 |

| Diameter of Aluminium Strands (*DAS*) (0-5) | |
|---|---|
| Below the min specification of 3.18mm | 5 |
| Between 0% and 0.4% (inclusive) above min specification of 3.18mm | 2.5 |
| Greater than 0.4% above min specification of 3.18mm | 0 |
| **Average Tensile Breaking Load of Outer Aluminium Strands (*TBL*) (0-20)** | |
| <1120N | 20 |
| >=1120N | 15 |
| >=1280N | 10 |
| >=1310N | 0 |
| **Torsion Test (Average Revolutions to Failure of Outer Aluminium Strands (*TT*) (0-20)** | |
| <1 revolution to failure | 20 |
| >=1 revolution to failure | 15 |
| >=10 revolutions to failure | 5 |
| >=18 revolutions to failure | 0 |

*Table 42*

Eddy current non-intrusive core corrosion rating measure the residual zinc coating of the steel core within ACSR. These employ a device that is required to be mounted on and propelled down a conductor wire. Changes in magnetic flux density detect loss of zinc and aluminium to the steel core.

| Core Sample Interpretation | *Score (COR)* |
|---|---|
| Aluminium loss detected | 80 |
| Residual zinc coating of 5 microns or less ('Severe Corrosion') | 50 |
| Residual zinc coating of >5 to <=20 microns ('Partial Corrosion') | 30 |
| Minimum | 0 |

*Table 43*

A 'Joint' factor is made up of a 'Tate' joint multiplier and infra red survey score.

A multiplier is assigned for OHL 'Tate' joints to reflect that this type of joint is inferior to a hexagonal compression. If 'Tate' joints are present then TATE=2, otherwise 1. The score applied can be seen above, in section 14.4.2.

### 14.4.5 OHL Fittings Parameters

Overhead Line Fittings are assigned an EoL modifier using a 2 stage calculation process. The first stage is preliminary assessment based on age. The second stage is based on visual condition assessment (referred to as a 'Level 1'), an 'outage' or intrusive condition assessment ('Level 2'), current defects and failure history.

Scoring assessments are made on sections of circuit that are typically homogenous in conductor type, installation date and environment.

### 14.4.5.1 OHL Fittings Failure Mode Grouping

OHL fitting assets are currently split into two different failure mode groups each of which has a different earliest and latest onset of failure value, and therefore a different AAL. These groupings are Quad Conductor Routes and Twin & Triple Conductor Routes

### 11.4.5.2 OHL Fittings End of Life Modifier

OHL fitting assets are currently split into two different failure mode groups each of which has a different earliest and latest.

The formula to determine the EoL modifier of fittings is given below and is capped at a maximum of 83. EOL mod 83 in this case equates to a state requiring replacement, i.e. a probability of failure of 10%.

$$EoLmod = \max(SPA, DAM, INS, PHF)$$
**Equation 74**

Where
SPA = Spacers
DAM = Dampers
INS = Insulators
PHF = Phase fittings, including linkages (shackles, straps, dowel pins etc.) and Arcing Horns/Corona Rings.

A maximum score of spacers, dampers, insulators, and phase fittings is applied since the conditional probability of the asset failing is determined by the weakest component. In this case the most deteriorated component is the component that has the highest EoL modifier component score.

The components of this formula will all be broken down and described in more detail below.

The score for the NARM reporting unit is calculated as below for each component class (spacers, dampers, insulators, and phase fittings). It remains necessary to review the results for each tower and span across the NARM reporting unit level to understand the distribution of condition across the system. A targeted intervention may be required within a component class or within a sub section of the OHL circuit or both. To guard against the averaging effect of large routes masking specific sections requiring attention, a threshold volume of 4.5km is used as below. This is equivalent to our smaller routes and is roughly three sections or 15 towers/spans. Our research shows distinct operating environments can be localised to a span or section. It is likely that intervention may be required on a small number of sections within a larger route.

The 'asset' below is defined as tower (for insulators, linkages, and dampers) or span (spacers). Further explanation on how to apply the logic in the criteria column of the table is explained below in the preliminary assessment section.

| Asset Health Score | Criteria |
|---|---|
| 0 | >=50% of Assets or 4.5 circuit km are New Assets, Less than 5 years Old |
| 10 | >=50% of Assets or 4.5 circuit km scoring 10 or more |
| 20 | >=50% of Assets or 4.5 circuit km scoring 20 or more |
| 30 | >=50% of Assets or 4.5 circuit km scoring 30 or more |
| 40 | >=50% of Assets or 4.5 circuit km scoring 40 or more |
| 50 | >=50% of Assets or 4.5 circuit km scoring 50 or more |
| 60 | >=50% of Assets or 4.5 circuit km scoring 60 or more |
| 70 | >=50% of Assets or 4.5 circuit km scoring 70 or more |
| 80 | >=50% of Assets or 4.5 circuit km scoring 80 or more |
| 90 | >=50% of Assets or 4.5 circuit km scoring 90 or more |
| 100 | >=50% of Assets or 4.5 circuit km scoring 100 |

**Table 44**

### 14.4.5.3 OHL Fittings Preliminary Assessment

The Preliminary assessment of spacers, dampers, insulators, and phase fittings is based on the age of the oldest components versus the anticipated life. The preliminary score for each of these components ($SPA_{PRE}$, $DAM_{PRE}$, $INS_{PRE}$, $PHS_{PRE}$) can be determined from the equation below. The preliminary score for each component SPA$_{PRE}$, DAM$_{PRE}$, INS$_{PRE}$ and PHS$_{PRE}$ is capped at 70.

$$SPA_{PRE}, DAM_{PRE}, INS_{PRE}, PHS_{PRE} = \begin{cases} 0 & AGE - AAL \leq -13 \\ 30(AGE - AAL) + 390 & -13 < AGE - AAL < -3 \\ 300 & AGE - AAL \geq -3 \end{cases}$$

**Equation 75**

### 14.4.5.4 Level 1 and Level 2 Condition Assessment

Each of the categories, spacers, dampers, insulators, and phase fittings are assessed against condition statements. Each of these statements has a weighting which results in the overall End of Life modifier.

Level 1 is a visual condition assessment of fittings components. The usual method of data collection is by High Definition Camera mounted to a helicopter.

Level 2 is an 'outage' or 'intrusive' condition assessment. This extra degree of inspection is required on those components likely to produce 'false negative' or 'false positive' results when the level 1 approach is adopted. This includes wear to phase fittings and loss of dielectric strength in insulation. Only some of the components have level 2 information.

### 14.4.5.5 Spacer Assessment

$$SPA = \frac{(SPA_{PRE} * LVL1) + SPA_{OvCA}}{6}$$

**Equation 76**

Where:

SPA = The overall spacer score

$SPA_{PRE}$ = The preliminary spacer score

LVL1 = A multiplier: if Level 1 condition assessment is available (=0), if Level 1 condition assessment is not available (=1)

$SPA_{OvCA}$ = The overall Condition Assessment score for spacers

$SPA_{OvCA}$ is a function of the percentage of assets falling into scores. 0-100 following:

- Level 1 condition assessment(SPA$_{LV1}$)
- Level 2 condition assessment from the route (SPA$_{LV2}$)
- latest defects from annual foot patrols (SPA$_{CDEF}$)
- failures(SPA$_{FAIL}$).

These are then multiplied by an operating environment modifier.

To calculate $SPA_{OvCA}$ on NOMs Reporting Unit Level, an SPA$_{CA}$ score is first calculated for all assets in each NOMs unit as described below. The $SPA_{OvCA}$ value is then given by the maximum of:

a) The score where 50% or more of assets in that NOMs unit have this SPA$_{CA}$ score.
b) The maximum SPA$_{CA}$ score is obtained from circuits that are 4.5km or longer.

For an individual span:

$$SPA_{CA} = \frac{\max(SPA_{LVL1}, SPA_{LVL2}, SPA_{CDEF}, SPA_{FAIL})}{6} * (ENV_{MOD})$$

**Equation 77**

where:

$SPA_{FAIL}$ = 500 if ≥2.5% of population of family on the route has failed in last five years, else 0.

$$ENV_{MOD} = \begin{cases} 1.2 & if\ A \\ 1.1 & if\ B \\ 1 & if\ C \\ 1.2 & if\ D \\ 1 & if\ not\ A, B, C\ or\ D \end{cases}$$

**Equation 78**

where:

| Environment Modifier | Description |
|---|---|
| A | Heavy Pollution – 5 km of a coast or major estuary, or within 10km downwind of an older, low stack coal fired power station or adjacent to chemical plant. |
| B | Some Pollution – 5-15km from a coast or major estuary or in an industrial area or on high ground downwind of pollution source |
| C | No Pollution – Rural areas at least 15km from the coast |
| D | Wind Exposed – High ground >150 metres above sea level, or areas with known sub-conductor oscillation and/or galloping problems |

**Table 45**

Spacer Visual Condition statements SPA$_{LVL1}$ & SPA$_{CDEF}$

| Spacers | Good Condition | Dull Appearance | Black Appearance | Slight Oxidation Deposits Around Conductor Clamp and Locking Pins | Severe Oxidation Deposits Around Conductor Clamp and Locking Pins |
|---|---|---|---|---|---|
| Tight and Secure | 100 | 200 | 300 | 400 | 500 |
| Locking Pins Ineffective or Loose | 600 | 600 | 600 | 600 | 600 |
| Rubber Missing | 600 | 600 | 600 | 600 | 600 |
| Loose Arms | 600 | 600 | 600 | 600 | 600 |
| Clamps Loose | 600 | 600 | 600 | 600 | 600 |
| Clamps Open | 600 | 600 | 600 | 600 | 600 |
| Missing | 600 | 600 | 600 | 600 | 600 |

**Table 46**

Spacer InTRUSIVE Condition statements SPA$_{LVL2}$

| Conductor Samples from Spacer Families on the Same Route and Environment | Good Condition | Dull Appearance | Black Appearance | Slight Oxidation Deposits Around Conductor Clamp and Locking Pins | Severe Oxidation Deposits Around Conductor Clamp and Locking Pins | Galvanic Corrosion between Rubber and Aluminium | Tensile Breaking Load <1310N but >=1114N Torsion Fail 5-15 Revs | Tensile Breaking Load <1114N Torsion Failure <5 Revs |
|---|---|---|---|---|---|---|---|---|
| Flattening/ Deformation of Conductor Wire | 300 | 300 | 400 | 500 | 600 | 600 | 400 | 500 |
| Heavy Fretting of Conductor Wires (>=50% of wire area indented in any layer) | 300 | 300 | 400 | 500 | 600 | 600 | 400 | 500 |
| Broken Conductor Wires | 600 | 600 | 600 | 600 | 600 | 600 | 600 | 600 |

**Table 47**

The Preliminary assessment of spacers, dampers, insulators, and phase fittings is based on the age of the oldest components versus the anticipated life.

### 14.4.5.6 Damper Assessment

$$DAM = \frac{(DAM_{PRE} * LVL1) + DAM_{OvCA}}{6}$$

<div align="center">**Equation 79**</div>

where:

$DAM$ = The overall damper score

$DAM_{PRE}$ = The preliminary damper score

$LVL1$ = A multiplier: if Level 1 condition assessment is available (=0), if Level 1 condition assessment is not available (=1). There is no Level 2 stage assessment for dampers.

$DAM_{OvCA}$ = The overall condition assessment score for dampers which is a function of the percentage of assets falling into scores 0-100 following Level 1 condition assessment, latest defects from annual foot patrols, and failures. These are then multiplied by an operating environment modifier.

To calculate $DAM_{OvCA}$ on NOMs Reporting Unit Level a DAM$_{CA}$ score is first calculated for all assets in each NOMs unit as described below. The $DAM_{OvCA}$ value is then given by the maximum of:

a) The score where 50% or more of assets in that NOMs unit have this DAM$_{CA}$ score.
b) The maximum DAM$_{CA}$ score is obtained from circuits that are 4.5km or longer.

For an Individual Span:

$$DAM_{CA} = \frac{\max\left(DAM_{LVL1}, DAM_{CDEF}, DAM_{FAIL}\right)}{6} * (ENV_{MOD})$$

<div align="center">**Equation 80**</div>

where:

$DAM_{FAIL}$ = 500 if ≥2.5% of population of family on the route has failed in last five years, else 0.

$$ENV_{MOD} = \begin{cases} 1.2 & if\ A \\ 1.1 & if\ B \\ 1 & if\ C \\ 1.2 & if\ D \\ 1 & if\ not\ A, B, C\ or\ D \end{cases}$$

<div align="center">**Equation 81**</div>

where:

| Environment Modifier | Description |
|---|---|
| A | Heavy Pollution – 5 km of a coast or major estuary, or within 10km downwind of an older, low stack coal fired power station or adjacent to chemical plant. |
| B | Some Pollution – 5-15km from a coast or major estuary or in an industrial area or on high ground downwind of pollution source |
| C | No Pollution – Rural areas at least 15km from the coast |
| D | Wind Exposed – High ground >150 metres above sea level, or areas with known sub-conductor oscillation and/or galloping problems |

<div align="center">**Table 48**</div>

Damper Visual Condition statements DAM$_{lvl1}$& DAM$_{CDEF}$

| Damper | Galvanising Weathered, Dull Appearance | Galvanised Coating Starting to Deteriorate | Light Rust, Majority of Galvanised Coating Missing | Heavy Rust | Heavy Corrosion, Pitting of Steelwork and Some Section Loss |
|---|---|---|---|---|---|
| 0-20° Droop | 100 | 100 | 200 | 200 | 300 |
| 20°-40° Droop | 100 | 100 | 200 | 300 | 400 |
| 40° + Droop | 600 | 600 | 600 | 600 | 600 |
| Bell(s) missing, messenger wire broken or slipped | 600 | 600 | 600 | 600 | 600 |
| Slipped | 600 | 600 | 600 | 600 | 600 |
| Missing | 600 | 600 | 600 | 600 | 600 |

**Table 49**

### 14.4.5.7 Insulator Assessment

$$INS = \frac{(INS_{PRE} * LVL1) + INS_{OvCA}}{6}$$

**Equation 82**

Where:
$INS$ = The overall insulator score
$INS_{PRE}$ = The preliminary insulator score
$LVL1$ = A multiplier: if Level 1 condition assessment is available (=0), if Level 1 condition assessment is not available (=1)
$INS_{OvCA}$ = The overall condition assessment score for insulators which is a function of the percentage of assets falling into scores 0-100 following Level 1 condition assessment, Level 2 condition assessment from the route, latest defects from annual foot patrols, and failures. These are then multiplied by an operating environment modifier.

To calculate $INS_{OvCA}$ on NOMs Reporting Unit Level an INS$_{CA}$ score is first calculated for all assets in each NOMs unit as described below. The $INS_{OvCA}$ value is then given by the maximum of:
   a)  The score where 50% or more of assets in that NOMs unit have this INS$_{CA}$ score.
   b)  The maximum INS$_{CA}$ score is obtained from circuits that are 4.5km or longer.

The effect of wind exposure is smaller on insulators than linkages, spacers, and dampers. The environment modifier ($ENV_{MOD}$) takes into account increased time of wetness associated with these environments (increase corrosion) and generally the higher likelihood of lightning strike (height above sea level)

For an Individual Span:

$$INS_{CA} = \frac{\max\left(INS_{LVL1}, INS_{LVL2}, INS_{CDEF}, INS_{FAIL}\right)}{6} * (ENV_{MOD})$$

**Equation 83**

where:

$INS_{FAIL}$ = 500 if ≥2.5% of population of family on the route has failed in last five years, else 0.

$$ENV_{MOD} = \begin{cases} 1.2 & if\ A \\ 1.1 & if\ B \\ 1 & if\ C \\ 1.1 & if\ D \\ 1 & if\ not\ A, B, C\ or\ D \end{cases}$$

**Equation 84**

where:

| Environment Modifier | Description |
|---|---|
| A | Heavy Pollution – 5 km of a coast or major estuary, or within 10km downwind of an older, low stack coal fired power station or adjacent to chemical plant. |
| B | Some Pollution – 5-15km from a coast or major estuary or in an industrial area or on high ground downwind of pollution source |
| C | No Pollution – Rural areas at least 15km from the coast |
| D | Wind Exposed – High ground >150 metres above sea level, or areas with known sub-conductor oscillation and/or galloping problems |

**Table 50**

Insulator Visual Condition Assessment $INS_{LVL1}$ & $INS_{CDEF}$

| Insulator | Galvanising Weathered, Dull Appearance | Galvanised Coating Starting to Deteriorate | Light Rust on Bells, Majority of Galvanised Coating Missing | Heavy Rust on Bells | Bells Severely Corroded and Some Section Loss |
|---|---|---|---|---|---|
| No Pollution | 100 | 200 | 200 | 300 | 300 |
| Evidence of Light Pollution | 200 | 300 | 300 | 300 | 400 |
| Evidence of Heavy Pollution | 300 | 300 | 300 | 300 | 400 |
| Visible Burn Marks | 400 | 400 | 500 | 500 | 500 |
| Evidence of Crazing | 600 | 600 | 600 | 600 | 600 |

**Table 51**

Insulator Intrusive Condition Assessment $INS_{LVL2}$ & INS$_{CDEF}$

| Insulator Resistance Testing from Insulator Families on the Same Route and Environment | Galvanising Weathered, Dull Appearance | Galvanised Coating Starting to Deteriorate | Light Rust on Bells, Majority of Galvanised Coating Missing | Heavy Rust on Bells | Bells Severely Corroded and Some Section Loss to Pins <10% for 190kN <2.5% for 300kN | Loss of Steel Pin Area 10% for 190KN, 2.5% for 300kN | Loss of Steel Pin Area 40% for 190KN, 10% for 300kN |
|---|---|---|---|---|---|---|---|
| Evidence of Failed units but string or set do not meet 'failed' criteria of 3 in a single string or 6 in a bundle | 300 | 300 | 300 | 400 | 400 | 500 | 500 |
| A single String or Set fails Meggar Test Criteria (3 in a string or 6 in a bundle) | 600 | 600 | 600 | 600 | 600 | 600 | 600 |

**Table 52**

## 14.4.5.7 Phase Fitting Assessment

$$PHF = \frac{(PHF_{PRE} * LVL1) + PHF_{OvCA}}{6}$$

**Equation 85**

Where:

$PHF$ = The overall phase fittings score

$PHF_{PRE}$ = The preliminary phase fittings score

$LVL1$ = A multiplier: if Level 1 condition assessment is available (=0), if Level 1 condition assessment is not available (=1)

$PHF_{OvCA}$ is the overall condition assessment score for phase fittings which is a function of the percentage of assets falling into scores 0-100 following Level 1 condition assessment, Level 2 condition assessment from the route, latest defects from annual foot patrols and failures. These are then multiplied by an operating environment modifier.

To calculate $PHF_{OvCA}$ on NOMs Reporting Unit Level a PHF$_{CA}$ score is first calculated for all assets in each NOMs unit as described below. The $PHF_{OvCA}$ value is then given by the maximum of:

  a)  The score where 50% or more of assets in that NOMs unit have this PHF$_{CA}$ score.
  b)  The maximum PHF$_{CA}$ score is obtained from circuits that are 4.5km or longer.

For an Individual Span:

$$PHF_{CA} = \frac{\max{(PHF_{LVL1}, PHF_{LVL2}, PHF_{CDEF}, PHF_{FAIL})}}{6} * (ENV_{MOD})$$

**Equation 86**

where:

$PHF_{FAIL}$ = 500 if ≥2.5% of population of family on the route has failed in last five years, else 0.

$$ENV_{MOD} = \begin{cases} 1.2 & if\ A \\ 1.1 & if\ B \\ 1 & if\ C \\ 1.2 & if\ D \\ 1 & if\ not\ A, B, C\ or\ D \end{cases}$$

**Equation 87**

where:

| Environment Modifier | Description |
|---|---|
| A | Heavy Pollution – 5 km of a coast or major estuary, or within 10km downwind of an older, low stack coal fired power station or adjacent to chemical plant. |
| B | Some Pollution – 5-15km from a coast or major estuary or in an industrial area or on high ground downwind of pollution source |
| C | No Pollution – Rural areas at least 15km from the coast |
| D | Wind Exposed – High ground >150 metres above sea level, or areas with known sub-conductor oscillation and/or galloping problems |

**Table 53**

$PHF_{LVL1}$ is the Level 1 Condition Assessment score for phase fittings.
$PHF_{LVL}$  is the Level 2 Condition Assessment score for phase fittings.

Phase Fittings are made up of
1.  Suspension Linkages: Shackle, Ball Ended Eye Link, Yoke Plate, Shoes, Maintenance Bracket, Weights, Straps. ($LNK_{SUS}$)
2.  Tension Linkages: Landing Pin, Shackle, Ball Ended Eye Link, Straps, Yoke Plate. ($LNK_{TEN}$)
3.  Arcing Horns and Corona Rings. ($ARC$)
4.  Dowel Pins and Bolts. ($DOW$)

$$PHF_{LVL1} = \max{((max(LNK_{SUS})), (max(LNK_{TEN})), ARC, DOW)}$$

**Equation 88**

$$PHF_{LVL2} = \max{((max(LNK_{SUS})), (max(LNK_{TEN})), DOW)}$$

**Equation 89**

Where
*max(LNK$_{SUS}$)* = Maximum of all suspension linkages on the tower
*max(LNK$_{TEN}$)* = maximum of all tension linkages on the tower.

There is no Level 2 assessment for Arcing Horns and Corona Rings. These have their own set of condition statements and scores as set out below.

$PHF_{LVL1}$ & PHF~CDEF~ Suspension and Tension Linkages, Dowel Pins and BOlts

| Phase and Earthwire Fittings (Suspension & Tension), Dowel Pins and Bolts | Galvanising Weathered, Dull Appearance | Galvanised Coating Starting to Deteriorate | Light Rust, Majority of Galvanised Coating Missing | Heavy Rust | Heavy Corrosion, Pitting of Steelwork and Some Section Loss |
|---|---|---|---|---|---|
| Minimal Wear 0-10% | 100 | 200 | 300 | 300 | 400 |
| Slight Wear 10-20% | 200 | 300 | 300 | 400 | 500 |
| Moderate Wear 20-40% | 300 | 300 | 400 | 500 | 500 |
| Heavy Wear 40-60% | 400 | 400 | 500 | 600 | 600 |
| Severe Wear >60% | 600 | 600 | 600 | 600 | 600 |

**Table 54**

$PHF_{LVL1}$ & PHF~CDEF~ Arcing Horns and Corona Rings

| Arcing Horn/ Corona Ring | Galvanising Weathered, Dull Appearance | Galvanised Coating Starting to Deteriorate | Light Rust, Majority of Galvanised Coating Missing | Heavy Rust | Heavy Corrosion, Pitting of Steelwork and Some Section Loss |
|---|---|---|---|---|---|
| Tight and Secure | 100 | 200 | 300 | 400 | 500 |
| Missing Components, Locking Nuts etc | 300 | 400 | 400 | 400 | 500 |
| Loose | 400 | 400 | 500 | 500 | 500 |
| Missing | 600 | 600 | 600 | 600 | 600 |
| Incorrect Length | 600 | 600 | 600 | 600 | 600 |

**Table 55**

$PHF_{LVL2}$ & PHF$_{CDEF}$ Suspension and Tension Linkages, Dowel Pins and BOlts

| Intrusive assessment of Linkages from the same route and environment | Material Loss of Steel through corrosion < 20% Cross Sectional Area | Material Loss of Steel through corrosion >= 20% Cross Sectional Area | Material Loss of Steel through corrosion >= 40% Cross Sectional Area |
|---|---|---|---|
| Minimal Wear 0-10% | 300 | 400 | 600 |
| Slight Wear 10-20% | 400 | 500 | 600 |
| Moderate Wear 20-40% | 500 | 600 | 600 |
| Heavy Wear 40-60% | 600 | 600 | 600 |
| Severe Wear >60% | 600 | 600 | 600 |
| Missing/ Out of Plumb >20$^0$/ Cracked Wedge Clamp | 600 | 600 | 600 |

**Table 56**

### 14.4.5.8 Overall End of Life Modifier for OHL Fittings

The end of life modifier formula for fittings given at the beginning of this section is reproduced below with a mathematical summary of how each component is determined.

$$EOLmod = \max(SPA, DAM, INS, PHF)$$
**Equation 74**

Where:

$$SPA = \frac{(SPA_{PRE} * LVL1) + SPA_{OvCA}}{6}$$
**Equation 76**

$$DAM = \frac{(DAM_{PRE} * LVL1) + DAM_{OvCA}}{6}$$
**Equation 79**

$$INS = \frac{(INS_{PRE} * LVL1) + INS_{OvCA}}{6}$$
**Equation 82**

$$PHF = \frac{(PHF_{PRE} * LVL1) + PHF_{OvCA}}{6}$$
**Equation 85**

The overall condition assessment (OvCA) is determined from the underlying condition assessment (CA) for each span according to the logic described above.

For an Individual Span the condition assessment score is determined from the following formula:

$$SPA_{CA} = \frac{\max(SPA_{LVL1}, SPA_{LVL2}, SPA_{CDEF}, SPA_{FAIL})}{6} * (ENV_{MOD})$$
**Equation 77**

$$DAM_{CA} = \frac{\max(DAM_{LVL1}, DAM_{CDEF}, DAM_{FAIL})}{6} * (ENV_{MOD})$$
**Equation 80**

$$INS_{CA} = \frac{\max(INS_{LVL1}, INS_{LVL2}, INS_{CDEF}, INS_{FAIL})}{6} * (ENV_{MOD})$$
**Equation 83**

$$PHF_{CA} = \frac{\max(PHF_{LVL1}, PHF_{LVL2}, PHF_{CDEF}, PHF_{FAIL})}{6} * (ENV_{MOD})$$
**Equation 86**

# 15 Long Term Risk Benefit

**Measuring LTRB is central to the reporting of replacement activities within RIIO-T2, and annual regulatory reporting. This section details what LTRB is and how it is calculated.**

## 15.1 Introduction

The following section describes the concept and calculation examples for Long-term Risk Benefit (LTRB) as applied to NGET's implementation of monetised risk. When an intervention takes place, the asset's monetised risk will be reduced in all years after the intervention. The LTRB is the sum of those risk reductions across a specified horizon (45 years, with the exception of Circuit Breaker Refurbishments which are assumed to survive up to 20 years). For its calculation, NGET has adopted the "Analytical" methodology proposed by Ofgem. Note that the simpler "Survival model" methodology was not suitable for NGET's predominantly older asset base.

## 15.2 LTRB Overview

As an asset's condition deteriorates, it's monetised risk increases. When an intervention is completed, the risk is mitigated; either by replacing the asset with a new item, or servicing components that lead to maintenance failure modes. The consequences of the failure of the new or maintained item, assuming like-for-like replacement, remain identical, but the probability of failure is reduced.

LTRB examines the risk reduction benefit over multiple years rather than only focussing on the year of the intervention. Calculating LTRB requires the evaluation of two scenarios:

1) Intervention in year X. A replacement intervention is carried out on an asset, resulting in reduction in risk. The risk will then start to increase again as the new asset deteriorates per the deterioration curves.
2) No intervention. No replacement intervention is modelled, the asset continues to deteriorate, and hence the asset eventually fails.

Note that for both of the modelled scenarios, maintenance activities continue. Simulating LTRB requires the use of assumptions regarding maintenance frequency for they cannot be modelled in operational terms over a timeframe of 50 years.

The key difference between the analytical and survival models is that the former assumes that once an asset fails, it is replaced with a new one. A survival model would otherwise assume the asset is eliminated; illustrated in Figure 25.



Figure 25

### 15.3 Concept of Asset Survival

The LTRB calculation has the concept of survival built into the method. This follows the norm that an asset is not immortal, i.e. left on the system long enough it will eventually fail. In monetised risk, high criticality assets exhibit rapid growth (of risk) up to the point they fail.

At that point, unless a new asset takes its place, the risk would be eliminated from the system – this is the Asset Survival Model. Typically, if an asset fails catastrophically, it would be replaced with an item serving the same function. The analytical method is therefore most representative for NGET.

### 15.4 Assumptions

The calculation makes three fundamental assumptions

1) For the purposes of RIIO-T2 NARM reporting, all interventions are assumed to be carried out at the end of RIIO-T2 (31$^{st}$ March 2026). In other words, no benefit is obtained within RIIO-T2.
2) For the analytical method, as soon as an asset reaches its failure point, it is assumed that an identical asset with the same FMEA properties takes its place. This is referred to as a like-for-like replacement. In practice, this is not necessarily true e.g. where obsolete equipment types are being replaced; though the potential error this introduces to evaluating LTRB is limited.
3) For the purposes of RIIO-T2, the LTRB is calculated across 45 years (i.e. up to 2071), assuming a discount factor of 3.5% for 30 years, and then for 3.0% in subsequent years.

### 15.5 LTRB Method – Survival / Adjusted Risk

To calculate the total risk of all assets both the original and new asset deterioration curves are considered. This is summarised in the following expression. The risk associated with a particular asset in year Y is equal to:

$$Risk_Y = Survival\ Risk\ of\ old\ asset + Survival\ risk\ of\ replacement\ asset$$
**Equation 90**

In other words, because an asset has a probability of failing, we assume that a proportion of the time, it does fail; to be replaced by a new asset. We include the risk of that new asset as it ages in our risk calculation for each year. Mathematically, this is illustrated in Equation 91

$$Risk_Y = Prob_{OLD_Y} \times Risk_{OLD_Y} + \sum_{age=0}^{Years\ since\ start\ of\ period} Prob_{age} \times Risk_{age}$$
**Equation 91**

Where:
$Prob_{OLD_Y}$ = The probability an asset survives up to year Y.
$Risk_{OLD_Y}$ = Risk of the surviving asset in year Y.
$Prob_{age}$ = Probability an asset has been replaced by an asset of a specific age.
$age$ = The age of the replaced asset
$Risk_{age}$ = The risk of an asset at a particular age.

The probability there will be a replacement asset of a particular age will depend on the probability the asset was replaced in previous years. To illustrate this, if we replace 5 assets in 2022, we expect to have 5 assets of age 1 in 2023. This is illustrated in figure 26.
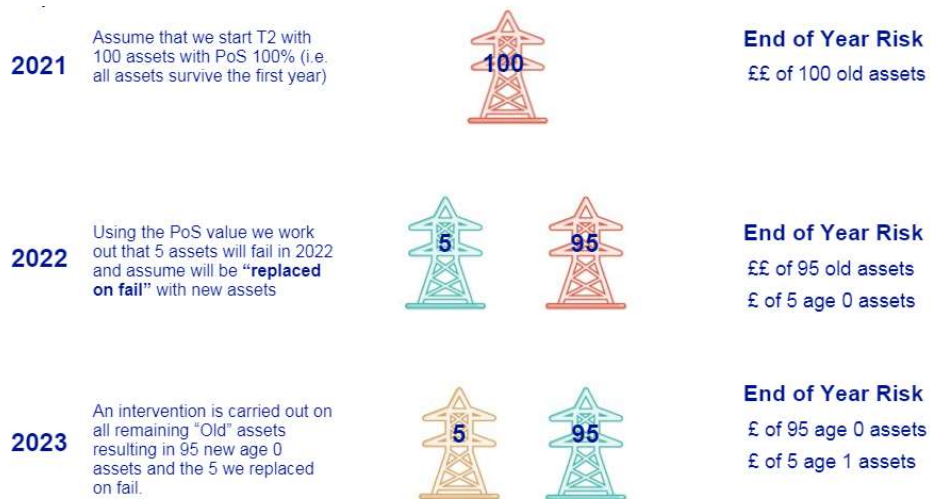
**Figure 26**

The probability there is a replacement asset of a specific age in year Y can be summarized using the following expression:

$$Prob_{age_Y} = Prob_{age-1_{Y-1}} \times PoS_{age}$$

**Equation 92**

Where:

$PoS_{age}$ = The cumulative probability an asset survives from age zero until a specific age.

Note that as replacement assets age, they too have a probability of failing and therefore trigger replacement that are included in the sum in Equation 92. Table 57 below gives an example of this calculation of cumulative probabilities of survival, and their evolution over time, for both a "no intervention" and "replacement" scenario.

Combining knowledge of the asset risk with survival probabilities for assets as they age, we can populate Equation 92

| | | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| No Intervention | (%) Old | 100.0% | 89.6% | 79.6% | 70.4% | 61.8% | 53.7% | 46.3% | 39.6% | 33.4% | 27.8% |
| | % Age 0 | | 10.4% | 10.0% | 9.2% | 8.7% | 8.2% | 7.6% | 7.0% | 6.5% | 6.1% |
| | % Age 1 | | | 10.4% | 10.0% | 9.2% | 8.7% | 8.2% | 7.6% | 7.0% | 6.5% |
| | % Age 2 | | | | 10.3% | 10.0% | 9.2% | 8.7% | 8.2% | 7.6% | 7.0% |
| | % Age 3 | | | | | 10.3% | 10.0% | 9.2% | 8.6% | 8.2% | 7.6% |
| | % Age 4 | | | | | | 10.2% | 9.9% | 9.1% | 8.6% | 8.1% |
| | % Age 5 | | | | | | | 10.1% | 9.8% | 9.0% | 8.5% |
| | % Age 6 | | | | | | | | 10.0% | 9.7% | 8.9% |
| | % Age 7 | | | | | | | | | 9.9% | 9.6% |
| | % Age 8 | | | | | | | | | | 9.8% |
| | | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| With Intervention | (%) Old | 100.0% | 89.6% | 79.6% | 70.4% | 61.8% | 53.7% | 0.0% | 0.0% | 0.0% | 0.0% |
| | % Age 0 | | 10.4% | 10.0% | 9.2% | 8.7% | 8.2% | 53.9% | 0.3% | 0.4% | 0.6% |
| | % Age 1 | | | 10.4% | 10.0% | 9.2% | 8.7% | 8.2% | 53.9% | 0.3% | 0.4% |
| | % Age 2 | | | | 10.3% | 10.0% | 9.2% | 8.7% | 8.2% | 53.9% | 0.3% |
| | % Age 3 | | | | | 10.3% | 10.0% | 9.2% | 8.6% | 8.2% | 53.7% |
| | % Age 4 | | | | | | 10.2% | 9.9% | 9.1% | 8.6% | 8.1% |
| | % Age 5 | | | | | | | 10.1% | 9.8% | 9.0% | 8.5% |
| | % Age 6 | | | | | | | | 10.0% | 9.7% | 8.9% |
| | % Age 7 | | | | | | | | | 9.9% | 9.6% |
| | % Age 8 | | | | | | | | | | 9.8% |

**Table 57 – Cumulative probabilities of survival over time, for an example SGT asset; comparing the effects of an intervention and no-intervention scenario**

The cumulative survival probability is multiplied by the asset risk for assets of corresponding age. For example, in 2022, we multiply 89.6% with the risk of the old asset at that year and 10.4% with the risk of a brand-new asset (age 0).

The total survival risk for that asset is calculated by summing up the risk components of each asset age. For reporting purposes, any replacements completed during RIIO-T2 are modelled as if the replacement is completed in 2026. The risk is reset to age zero as of 1st April 2027. This means the risks modelled for both the no intervention and replacement in 2026 scenarios for the T2 period (2021-2026) are identical. This assumption is necessary to avoid incentivising late interventions within RIIO-2.

For purposes of an example, let us assume all old assets are replaced in FY 2026. The proportion of "old" assets drops to zero in 2027. Table 58 shows the survival risk contribution for each age group, for both the "No intervention" and "with intervention" scenarios. Notice that from 2027 onwards we no longer have any contribution from the old asset for the replacement scenario.

**No Intervention**

| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| r£m (old) | 1.59 | 1.64 | 1.31 | 1.24 | 1.18 | 1.05 | 0.97 | 0.90 | 0.86 | 0.68 |
| r£m (Age 0) | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| r£m (Age 1) | | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| r£m (Age 2) | | | | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| r£m (Age 3) | | | | | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| r£m (Age 4) | | | | | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| r£m (Age 5) | | | | | | | 0.00 | 0.00 | 0.00 | 0.00 |
| r£m (Age 6) | | | | | | | | 0.01 | 0.01 | 0.01 |
| r£m (Age 7) | | | | | | | | | 0.00 | 0.00 |
| r£m (Age 8) | | | | | | | | | | 0.01 |

**With Intervention**

| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| r£m (old) | 1.59 | 1.64 | 1.31 | 1.24 | 1.18 | 1.05 | 0.00 | 0.00 | 0.00 | 0.00 |
| r£m (Age 0) | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 |
| r£m (Age 1) | | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.00 | 0.00 |
| r£m (Age 2) | | | | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.05 | 0.00 |
| r£m (Age 3) | | | | | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 | 0.12 |
| r£m (Age 4) | | | | | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| r£m (Age 5) | | | | | | | 0.00 | 0.00 | 0.00 | 0.00 |
| r£m (Age 6) | | | | | | | | 0.01 | 0.01 | 0.01 |
| r£m (Age 7) | | | | | | | | | 0.00 | 0.00 |
| r£m (Age 8) | | | | | | | | | | 0.01 |

Table 58 – Survival risk contributions for the no-intervention and replacement in 2026 scenarios (£M risk), for an example SGT

### 15.6 Discounted Nominal Benefit

The nominal benefit is the risk delta between the adjusted risk of the "no intervention" and "with-intervention" scenarios across all years of the calculation (out to 2071). To account for inflation, this delta is multiplied by a discount factor. Finally, the discounted delta is summed up across all years to provide the LTRB value for the intervention. This is summarised as the following expression:

$$LTRB_{Asset\ A} = \sum_{Y=1}^{Y_{horizon}} (SR'_{Int\ 2026} - SR'_{No\ Int}) \times (1 - f_D)^Y$$

**Equation 93**

Where:
$LTRB_{Asset\ A}$ = The long term benefit of the intervention
$Y_{horizon}$ = The horizon of the calculation (RIIO T2 this is 45 years)
$SR'$ = the adjusted risk calculated above
$f_D$ = the discount factor.

The discount factor is initially 3.5%, dropping to 3.0% in year 31, as per the definition in *Intergenerational wealth transfers and social discounting: Supplementary Green Book guidance*[11].

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[11] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/193938/Green_Book_supplementary_guidance_intergenerational_wealth_transfers_and_social_discounting.pdf

## 16 Differences With Other Network NARA

The NGET NARA is known to differ in some areas from that employed by other TO's and DNOs. This section is intended to highlight the important differences, reasons for them, and possible barriers to alignment.

NGET NARA differs in certain elements from DNO, Scottish ETOs and the Gas TO methodologies. While assessment and treatment of risk is similar, there are differences in the construction of networks and organisation's risk appetite that can influence how risk is modelled and treated. Many other networks include extensive radial connections, with little redundancy and covering long distances. The NGET NARA would evaluate such a connection to be high risk. The disparity in number of customers connected per asset mean one's decisions and strategy for managing that connection differ; and this is reflected in the differences between the different network NARAs.

With such varied types of connection and asset solutions; mitigations to risk are equally varied. Other TOs and DNOs routinely use mobile generation to either enable works or provide standby capability in event of failure. Such a solution is not practical for the quantities of energy carried on a typical NGET asset. Instead, the power must be re-routed to satisfy demand. Maintaining a reliable enough network to absorb potential faults and failures is reflected in both the System Design philosophy expressed in the SQSS (Security & Quality of Supply Standard) and the NGET NARA.

Sections 8.1.3 and 8.1.4 of NGET NARA discuss the probability and duration of fault, important parameters in determination of system consequences. These are influenced by the physical design and operational strategies of respective networks, for example the time to deploy personnel to a remote location has bearing on the time to recover post-fault. All three TO's have used a comparable approach to system consequences modelling; with differences in the assumptions arising from the differences in geography, system design and operational strategies employed.

Financial consequences are another area where differences are observed in the modelling between networks. The specific commercial terms and purchase prices of individual assets are confidential information and have bearing on model assumptions.

Concerning Failure Modes and Effects Analysis, NGET may have to give consideration to small asset populations; in some cases as low as one asset. This is in contrast to the DNO's CNAIM model, which enjoys the benefit of large asset populations, both nationally and globally, from which to derive useful statistics. Deriving useful statistics for small populations is a difficult task; necessitating the use of expert knowledge and judgement to populate. It would likely be difficult to quantify and align modelling assumptions for small population types.

The SPT and SHE-T NARA has a mechanism whereby any "unclassified" issue can be assigned an arbitrary EoL-modifier in response. There is no equivalent to this in the NGET NARA, noting that it was always understood that the NARA could not cover every possible set of conditions warranting intervention.

During RIIO-T1 closeout, NGET noted differences in approaches to overhead line modelling compared with the Scottish TOs. NGET models risk by "Routelet", that is, multiple spans usually of the same construction treated as a single asset in the risk model. Whereas the Scottish TO's report OHL risk at a per-span level. There is no specific barrier to aligning methodologies in this regard, other than the reporting requirements of RIIO-T2 itself; and work is underway as a category 2 modification to improve in this regard. (See Section 17).

An objective of calculating risk is as a decision support tool to inform intervention strategies. Both the NGET and SPT and SHE-T NARAs are valid methods for doing this; designed in line with respective network's risk appetites. However, differences in methodologies do not allow for a direct comparison of risk from one network to another; for they are built with different assumptions based on their own organisation's risk appetite and construction.

## 17 Future NARM Development

NARM and the Common Methodology are periodically reviewed in order to satisfy License Special Condition 9.2, and further the ongoing improvement of the Common Methodology and NARA in pursuit of the NARM Objectives.

Early 2022 both the TO's and Ofgem conducted a review of priority areas for development of both the Common Methodology and NARM. Priorities for development were jointly agreed, as were the timescales for development.

Category 1 modifications are those that form part of this issue (6) of the NARA and associated Common Methodology. These include improvements to the documentation of the Calibration, Testing and Validation processes; improvements to document transparency by consolidation of the Licensee-Specific Appendices wherever possible, improvement of the stakeholder engagement strategy, and a review of the differences, and possible barriers to alignment of different TO NARA.

Category 2 modifications are planned to be completed by November 2023. NGET is developing an update to both Cable and OHL Scoring methodologies in response to feedback on earlier work. The other major areas highlighted for development were the Calibration, Testing and Validation of System Consequences; and for public facing versions of technical guidance relevant to condition scoring to be produced.

No Category 3 modifications are currently under development. One item was highlighted at the review, to consider exploring the modelling of additional assets into NARM.

## Guidance Notes and Appendices

### REFERENCES

- ISO 55000 Asset Management standards
- BS EN 60812:2006 Analysis Techniques for System Reliability
- AA1000 Stakeholder Engagement Standard (AccountAbility, 2015)
- Intergenerational wealth transfers and social discounting: Supplementary Green Book
- CIGRE TB 309 Asset Management of Transmission Systems & Associated CIGRE Activities
- CIGRE TB 858 Asset Health Indices for Equipment in Existing Substations

## Appendix A. Assumptions Log

NGET -
Assumptions Log - C

## Appendix B. Calibration, Testing and Validation Activity Summary

While implementing the NARM Methodology, NGET conducted detailed Calibration, Testing and Validation (CTV) to ensure achievement of the NARM Methodology Objectives. A summary of the activities undertaken as part of Calibration, Testing and Validation (CTV) of the NARM Methodology are tabulated below.

| Element | Aim | Technique | Pass Measure |
|---|---|---|---|
| Further explanation of EoL modifier methodology with references | Explanation of rational that has been followed in determining functional form utilised within the EoL modifier approach. Reference where possible. | Workshops, expert review, reference industry standard approaches | A document supporting the formulae in the EoL modifier methodology - Approved by internal expert reviewers |
| End of life failure mode | To confirm the derivation of Asset Health Index / EoL modifier is in line with the NARM Methodology | Review the implementation of all elements of EoL modifier derivation, verify that implementation is correct using manual or spreadsheet calculation where necessary | Verification that all elements of the derivation of the probability of failure are implemented as described in the Methodology. |
| All Licensees - EoL modifier comparison | Compare EoL Modifiers for a sample of assets across each of the TNOs | Comparability testing between the TNOs via sampling of assets across a range of EoL modifiers. Subject matter experts to assess outputs from this analysis to understand differences and ensure comparability. | Meets licence requirements - model provides a like for like comparison of EoL modifiers across different categories of assets |
| FMEA output: failure mode, failure rate (indicative), frequency of events (indicative), and detection; probability of events | To use the failure, fault, and defect database to validate those failure modes used in the FMEA workshops which will validate credible probability of failure. Validate probability of events using fault, failure, and defects data | Data cleanse and data manipulation, guided by subject matter expert | Results from the fault, failure, and defect database is compatible with the expected output of events from FMEA/risk model |
| End of life failure mode | Where possible, validate the end-of-life failure mode for each asset type using data-driven methods | Justify end of life (EoL) failure modes using expert knowledge or/and data driven methods where appropriate. Calculate PoF and compare to expected number of replacements. | PoF and expected number of events agree. Validation provided for EoL FMs |

| Disruptive failure and Implied Probability of Disruptive Failure | While the probability of disruptive failures used, the failure database should be used to validate the probabilities | Statistical analysis, where data is available, and implied failure probability when data is not available, reviewed by engineering experts | The disruptive failure mode is appropriately addressed in the methodology with validated probabilities, in order to correctly model the scenarios associated with the disruptive failures |
|---|---|---|---|
| Assumption of independence

Data needed to model inter-dependence

The assumption of mutual exclusivity for failure modes | Test the assumptions of inter-dependence when the model combines different failure modes and events together using data facilitated by engineering knowledge and experience.

The model assumes the failure modes are independent but not mutually exclusive, i.e. in theory those modes can fail at the same time. Reviewing the definitions and physical process of the failure modes in the FMEA spreadsheet. | Data categorisation, facilitated by engineering knowledge. Review in the context of FMEA output validation. Tests performed to confirm that those are reflected in the model workshops, subject matter experts and collective opinion | The assumptions are shown to be valid or non-material |
| Survival curve EoL modifier validation | Validate that the relationship between EoL modifier score and age has expected relationship at population level for each type of asset then

Calibrate parameters in the EoL modifier to PoF mapping process using these outputs. Iterate this process as appropriate. | Translate end of life scores into survival curves and then use this to compare with the anticipated asset life, which is based on data, subject matter expert opinion and industrial best practice.

Align the different models and also align the models with data/engineering experience as detailed in the above two cases | Reasonable match to existing policy with differences understood and where possible quantified. The expected number of end of life related replacement events agree with our historical replacement data. |

| | | | |
|---|---|---|---|
| Cost of (material) consequence - the model | Review the process when introducing criticality (or any other asset specific information) into the cost of (material) consequence. At the same time, make sure the current criticality definition is appropriately translated into the probability of (material) consequence. | Independent review and comparison study, e.g. the definitions between the cost of (material) consequence and criticality | The definitions and approach are compatible and can be justified. And the cost of material consequence is compatible with the current criticality data (for example, criticality is currently represented by exposure and vulnerability, which might be duplicated with the probability of material consequence) |
| Cost of (material) consequence - the values for the disruptive failure. | Make sure the cost of (material) consequence values are in the right magnitude of order, and this exercise also helps to pin down the most suitable values that can be used for the monetised risk modelling | Data cleanse and data manipulation, comparison of expected costs of events with cost data where possible | The cost data supports the values of the cost of financial consequence data retained by the TOs |
| Financial Consequence | Validate the financial consequence values using cost data. Calibrate if validation fails. | Data cleanse and data manipulation, statistical analysis | The cost data supports the values of the cost of financial consequence data |
| Safety and environmental consequences | To validate the safety and environmental consequence values that are proposed in the NARM methodology, and calibrate if validation fails. | Compare the probability of events and cost of events from the modified NARM methodology with the historical events over the whole network for environmental and safety related events | The comparison study provides consistent outcomes (from the model and the historical records) |
| The return to service (RTS) time - system consequence | To validate the return to service time that is used to calculate the system consequence; to review and test the assumptions over the return to service time proposed in the FMEA workshops | Review the assumptions with the modelling and data, e.g. the RTS modelling use a single value to represent all the events/assets of this type; the RTS time is insensitive to asset condition, etc. | Those assumptions are supported by the data |

| | | | |
|---|---|---|---|
| Direct customer connection - system consequence | To validate the cost of system consequence toward the direct customer connection | Compare the probability of events and cost of events from the modified NARM methodology with the historical events over the whole network for disconnection of customers (supply and demand sides) related events | The total system consequence risk value derived from the NARM methodology has reasonable agreement with the cost of historical customer disconnection events. |
| Customer disconnections within System Consequence | To validate the probability and durations of customer disconnections against those predicted by another tool used to calculate the likelihood of customer disconnections, TRIP. | Calculate the probability and duration of customer disconnection for three customer sites using both tools and compare results. | The results align, to a reasonable degree, taking into account the differences in scope of the tools. |
| Data Load and Processing Routines | Ensure base data sets used by the Risk Model are correctly loaded and processed. Any corrupted /incorrect data is explicitly identified. | Unit test of data load procedures and validation against known data sets | Pass of Unit Testing. Data loaded of the correct dtypes. Incorrect data identified and exceptions raised. |
| Generation of Probability Distributions and Parameters | Generation of parameters for various distributions and validation of probability values for each distribution type | Unit testing against known results for each distribution type ensuring outputs of the model align with reference values | Model outputs agree with reference inputs. |
| Generation of PoF by Failure Mode and Asset Type and Generation of Effective DataFrames for each Asset | To confirm the calculations for the Probability of Failure (PoF) are correct | For a sample of the assets, ensure that the PoF calculations are correct, using manual or spreadsheet calculation where necessary | Ensure that the Asset.pof dataframe entirely matches the manual calculations, in all years, for all of the assets in the sample |
| Generation of PoE by Failure Mode and Asset Type | To confirm the calculations for the Probability of Event (PoE) are correct | For a sample of the assets, ensure that the PoE calculations are correct, using manual or spreadsheet calculation where necessary | Ensure that the Asset.poe dataframe entirely matches the manual calculations, in all years, for all of the Asset/Event combinations in the sample |
| Generation of Monetised Risk Scores | To confirm the calculations for the Monetised Risk Scores (Asset.wtd_risks) are correct | For a sample of the assets, ensure that the Monetised Risk Score calculations are correct, using manual or spreadsheet calculation where necessary | Ensure that the Asset.wtd_risks dataframes entirely matches the manual calculations, in all years, for all of the Assets in the sample |

Table 59