Network Output Measures Methodology

Issue 16

VERSION CONTROL

VERSION HISTORY

Date	Version	Comments
28/04/17	1	Submission

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GLOSSARY

Asset Risk	Term adopted that is synonymous with Condition Risk in the Direction
COMAH	Control of Major Accident Hazards
Consequence	Outcome of an event affecting objectives*
Consequence of Failure	A consequence can be caused by more than one Failure Mode. This is monetised values for the Safety, Environmental, System and Financial consequences
EKP	Economic Key Point
EOL	End of Life
Event	Occurrence or change of a particular set of circumstances*
Failure	A component no longer does what it is designed to do
Failure Mode	A distinct way in which a component can fail
FMEA	Failure Modes and Effects Analysis
FMECA	Failure Modes, Effects and Criticality Analysis
HILP	High Impact, Low Probability
Intervention	An activity (maintenance, refurbishment, replacement) that is carried out on an asset to address one or more failure modes
Level of risk	Magnitude of a risk or combination of risks, expressed in terms of the combination of consequences and their likelihood*
Likelihood	Chance of something happening*
NETS SQSS	National Electricity Transmission System Security and Quality of Supply Standard
Network Risk	The sum of all the Asset Risk associated with assets on a TO network
Probability of Failure	The likelihood that a Failure Mode will occur in a given time period
RIGs	Regulatory Instructions and Guidance
Risk	Effect of uncertainty on objectives*
Risk management	Coordinated activities to direct and control an organization with regard to risk*
TO	(Onshore) Transmission Owner

*Refer to Table 1 of the Common Methodology for source of these definitions

This Glossary will continue to be updated as the methodology is developed.

PURPOSE

The RIIO (Revenue = Incentives + Innovation + Outputs) regulatory framework places emphasis on incentives and outputs to drive the innovation that is needed to deliver a sustainable energy network to consumers.

Outputs are a fundamental element of the RIIO framework. The primary outputs monitor each onshore Transmission Owner's (TO) performance for the delivery of end services to consumers. The Network Output Measures (NOMs) are binding secondary outputs which show that the TOs are providing consumers with long-term value for money through a set of early warning measures or lead indicators. These assess the underlying performance of the transmission system.

The NOMs are 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 outputs. Using the NOMs, the TOs can identify the work needed to manage assets to deliver a known level of network risk, thus providing assurance that performance is maintained in future price control periods.

For the price control period (RIIO-T1) which covers the eight years from 1 April 2013 to 31 March 2021, special licence condition 2L sets out the requirements for the NOMs for each of the TOs.

Special Licence Condition 2L requires that the TOs have in place a methodology for a set of NOMs which are designed to enable the evaluation of:

1. Network Asset Condition
2. Network Risk
3. Network Performance
4. Network Capability
5. Network Replacement Outputs

In line with the Direction (30 April 2016), this draft Methodology focuses on modifications to the network asset condition measure, network risk measure and the Network Replacement Outputs. As there are no proposed modifications to the network performance measure and network capability measure, the final version of this methodology will include the approach from the existing methodology.

The NOMs methodology is based on the following key principles:

1. Compliance: Ensuring that the measures comply with the law

2. Measurable: Enable the Authority to assess whether the NOMs objectives have been achieved and whether the targets have been met

3. Consistency: Develop a common approach to ensure that the measures are consistent and comparable

4. Transparency to Stakeholders: Ensure that consumers are getting value for money – minimising the burden on current customers without creating unnecessary costs for future customers

5. Applicability: Ensure that the TOs' stewardship of our assets is appropriate and proportionate

6. Objectivity: Providing data/information for the Authority to enable evaluation of performance and for TOs to manage our assets

This NOMs methodology contains:

a. The requirements in the Licence Conditions and the Direction issued by Ofgem on 30th April 2016 including the explanation where development has been undertaken on a reasonable endeavours basis

b. The common framework describing how the NOMs are calculated

c. Faciliting the comparison of the NOMs with measures produced by other asset management organisations

d. Communication of information about the TOs' systems to Ofgem, including confidentiality issues surrounding publishing the content of this Network Output Measures methodology to external (outside Ofgem) parties

e. How the NOMs will be regularly reviewed and continuously improved by the TOs

LICENCE REQUIREMENTS

Special Licence Condition 2L requires that each licensee must at all times have in place and maintain a methodology for Network Output Measures ("the NOMs methodology") that:

a. Facilitates the achievement of the NOMs methodology objectives

b. Enables the objective evaluation of the NOMs

c. Is implemented by the licensee to provide information (whether historic, current, or forward looking) about the NOMs. This may be supported by such relevant other data and examples of network modelling as specified in any Regulatory Instructions and Guidance (RIGs) issued by the Authority in accordance with the provisions of Standard Licence Condition B15 of the Transmission Licence for the purpose of this condition

d. Can be modified in accordance with specific provisions.

The NOMs methodology objectives are designed to facilitate the evaluation of:

a. The monitoring of the licensee's performance in relation to the development, maintenance and operation of an efficient, co-ordinated and economical system of electricity transmission

b. The assessment of historical and forecast network expenditure on the licensee's Transmission System

c. The comparative analysis over time between GB transmission and distribution and with international networks

d. The communication of relevant information about the licensee's Transmission System to the Authority and other interested parties in an accessible and transparent manner

e. The assessment of customer satisfaction derived from the services provided by the licensee as part of its Transmission business

The NOMs methodology is designed to enable the evaluation of:

a. The Network Asset Condition measure, which relates to the current condition of the network assets, the reliability of the network assets, and the predicted rate of deterioration in the condition of the network assets, which is relevant to assessing the present and future ability of the network assets to perform their function

b. The Network Risk measure, which relates to the overall level of risk to the reliability of the licensee's Transmission system that results from the condition of the network assets and the interdependence between the network assets

c. The Network Performance measure, which relates to those aspects of the technical performance of the licensee's Transmission system that have a direct impact on the reliability and cost of services provided by the licensee as part of its Transmission business

d. The Network Capability measure, which relates to the level of the capability and utilisation of the licensee's Transmission system at entry and exit points and to other network capability and utilisation factors

e. The Network Replacement Outputs measure, which are used to measure the licensee's asset management performance as required in Special Licence Condition 2M (Specification of Network Replacement Outputs)

The methodology is designed to enable the evaluation of all five NOMs. Each measure is reported to the Authority annually to facilitate the ongoing assessment of each TO's performance, through the regulatory reporting process.

ONGOING REVIEW AND DEVELOPMENT OF THE NETWORK OUTPUT MEASURES

Part E of Special Licence Condition 2L requires that each licensee must, from time to time, and at least once every year, review the NOMs methodology to ensure that it facilitates the achievement of the methodology objectives.

The methodology is jointly review by all TOs. The TOs regularly discuss the methodology as well as the development of the NOMs. The terms of reference for these review meetings are: The TOs will meet to discuss the appropriateness of the current NOMs in meeting the requirements of Special Licence Condition 2L; share information to ensure consistency and calibration across the TOs; discuss and resolve common issues with the implementation of NOMs

Outside of the annual review, if a TO determines that a modification is needed to the NOMs methodology that TO will call for a joint review with the other TOs.

When it is agreed that changes should be made to better facilitate the achievement of the objectives, the TOs follow the process for consulting stakeholders, as defined in the Licence. Changes to the NOMs methodology and Licensee Specific Appendices will follow the process outlined below.

OFGEM DIRECTION

A Direction was issued by Ofgem on 30 April 2016, laying out further requirements for development of the draft Methodology. A report accompanies this issue which demonstrates compliance against the direction, identification of further work required and where development has been undertaken on a reasonable endeavours basis.

PROCESS TO MODIFY THE NETWORK OUTPUT MEASURES METHODOLOGY

Licence conditions 2L.10 and 2L.11 state that the licensee may make a modification to the NOMs methodology after:

a. Consulting with other Transmission Licensees to which this condition applies and with any other interested parties, allowing them a period of at least 28 days within which to make written representations with respect to the TO's modification proposal.

b. Submitting to the Authority a report that contains all of the matters that are listed below:

   i. A statement of the proposed modification to the NOMs methodology

   ii. A full and fair summary of any representations that were made to the licensee pursuant to paragraph 2L.10(a) and were not withdrawn

   iii. An explanation of any changes that the TO has made to its modification proposal as a consequence of representations

   iv. An explanation of how, in the licensee's opinion, the proposed modification, if made, would better facilitate the achievement of the NOMs methodology objectives

   v. A presentation of the data and other relevant information (including historical data, which should be provide, where reasonably practicable, for a period of at least ten years prior to the data of the modification proposal) that the licensee has used for the purpose of developing the proposed modification

   vi. A presentation of any changes to the Network Replacement Outputs, as set out in the tables in Special Licence Condition 2M (Specification of Network Replacement Outputs) that are necessary as a result of the proposed modification to the NOMs methodology

   vii. A timetable for the implementation of the proposed modification, including an implementation date

COMMON METHODOLOGY

1. INTRODUCTION

Risk is part of our everyday lives. In our everyday activities such as crossing the road and driving our cars we take risks. For these everyday activities we often do not consciously evaluate the risks but we do take actions to reduce the chance of the risk materialising and/or the impact if it does.

For example we reduce the chance of crashing into the car in front by leaving an ample stopping distance and we reduce the impact should a car crash happen by fastening our seat belts. In taking these actions we are managing risk.

Organisations are focussed on the effect risk can have on achieving their objectives e.g. keeping their staff, contractors and the public safe, providing an agreed level of service to their customers at an agreed price, protecting the environment, making a profit for shareholders.

Organisations manage risk by identifying it, analysing it and then evaluating whether the risk should and can be modified.

To help organisations to manage risks, the International Standards Organisation has produced ISO 31000:2009 Risk management - Principles and guidelines which includes a number of definitions, principles and guidelines associated with risk management which provide a basis for identifying risk, analysing risk and modifying risk. In addition, BS EN 60812:2006 provides useful guidance on analysis techniques for system reliability.

In this methodology we have utilised relevant content from ISO 55001, ISO 31000 and BS EN 60812. This includes definitions associated with risk as defined in ISO Guide 73:2009:

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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 1

Risk is often expressed in terms of a combination of the associated likelihood of an event (including changes in circumstances) and the consequences of the occurrence.

Likelihood can be defined, measured or determined objectively or subjectively, qualitatively or quantitatively, and described using general terms or mathematically (such as a probability or a frequency over a given time period).

Similarly, consequences can be certain or uncertain, can have positive and negative effects on objectives and 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 combination of likelihood and consequence is often expressed in a risk matrix where likelihood is placed on one axis and consequence on the other.

This combination is not necessarily mathematical as the matrix is often divided into categories on the rows and the columns and can be categorised in whatever form is applicable to the risks under consideration.

Sometimes this combination of likelihood and consequence is expressed mathematically as:

$$\text{Risk} = \text{Likelihood} \times \text{Consequence}$$

Equation 1

In this mathematical form whilst it is necessary for the likelihood and consequence to be expressed numerically for such an equation to work, the likelihood does not necessarily have to be a probability and the consequence can be expressed in any numeric form.

When using likelihood expressed as a probability and consequence expressed as a cost, using the risk equation this provides a risk cost. This risk cost enables ranking of the risk compared with others risks similarly calculated. This is true for any consequence expressed numerically on the same basis.

When considering a non-recurring single risk over a defined time period, the risk event has two expected outcomes, either the risk will occur resulting in the full consequence cost or the risk event will not occur resulting in a zero-consequence cost.

For this reason the use of summated risk costs for financial provision over a defined time period works best when there is a large collection of risks. This is because if only a small number of risks are being considered, a financial provision based on summated risk cost will either be larger or smaller than is actually required.

This is particularly the case for high-impact, low-probability (HILP) risks. It is generally unusual to have a large collection of HILP risks and so the summated risk cost does not give a good estimate of what financial provision is required. There are also particular considerations with respect to these risks when using risk cost to rank subsequent actions.

1.1. METHODOLOGY OVERVIEW

In order to ascertain the overall level of risk for each TO, the NOMs methodology will calculate Asset Risk for lead assets only, namely:

1. Circuit Breakers
2. Transformers
3. Reactors
4. Underground Cable
5. Overhead Lines
    - Conductor
    - Fittings
    - Towers (Scottish Power Transmission (SPT), Scottish Hydro Transmission (SHE-T) only)

As shown in Figure 1 and Equation 3, the Asset Risk is the sum of the expected values of each consequence associated with that asset. It is a function of the probability of each failure mode occurring, the probability of consequences given a failure, the effectiveness of detection and the impact of each of the consequences.

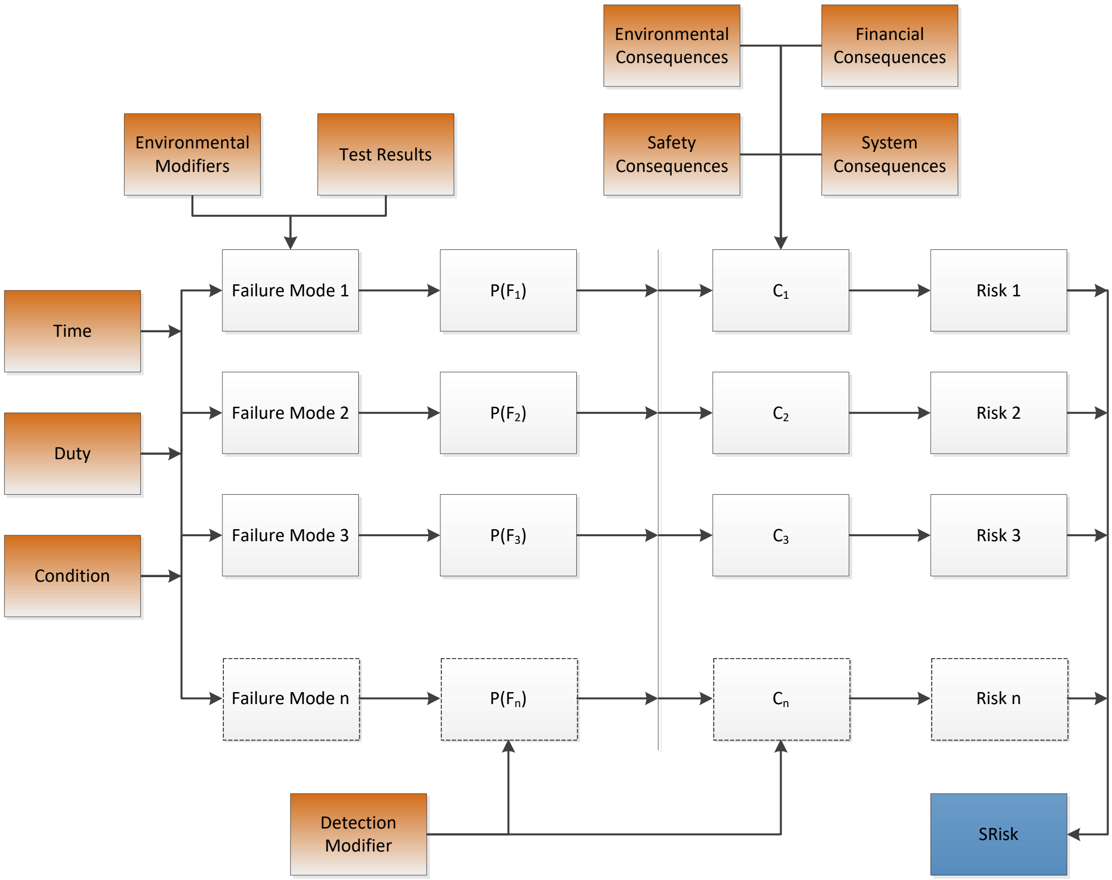


Figure 1

For reasons of economic efficiency, TOs do not consider every possible failure mode and consequence, only those which are materially significant. TOs' assessment of material significance is based upon their experience and consequential information set. TOs have different information sets and therefore have made different decisions, within the same overall methodology, about what should be measured or calculated from first principles and what must be estimated. It is these differences that require flexibility in the application of Failure Modes and Effects Analysis (FMEA).

The NGET implementation of this methodology considers the failure modes which they have explored in detail, supported by available data. The SPT/SHE-T implementation of this methodology considers only the condition-related failure modes which have measurable effects on the specified requirement and function. This is done using historical data, where available, and estimated where there is no data available. Because the SPT / SHE-T implementation implicitly considers the failure effects when mapping the inputs to failure modes, the mapping of failure modes to consequences is relatively simple. For NGET this mapping is more complex and is supported by historical data where this is available and estimated where there is no data available.

The implementation for NGET and SPT/SHE-T is detailed in the relevant Process Appendix.

1.1.1. ASSET (A)

An asset is defined as a unique instance of one of the above five types of lead assets. Overhead Line and Cable routes will be broken down into appropriate segments of the route. Each Asset belongs to an Asset Family. An Asset Family has one or more material Failure Modes. A material Failure Mode can lead to one or more Consequences.

1.1.2. MATERIAL FAILURE MODE (F)

The material failure mode is a distinct way in which an asset or a component may fail. Fail means it no longer does what is designed to do and has a significant probability of causing a material consequence. Each failure mode needs to be mapped to one or more failure mode effects.

Each failure mode (F_i) needs to be mapped to one or more consequences (C_j) and the conditional probability the consequence will manifest should the failure occur $P(C_j|F_i)$.

However, where failure modes and consequences have a one-to-one mapping, this function is not required and the Probability of Failure is equal to the Probability of Consequence.

1.1.3. PROBABILITY OF FAILURE P(F)

Probability of failure ($P(F_i)$) 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 rate, earliest and latest onset of failure) are provided by FMEA. The probability of failure is influenced by a number of factors, including time, duty and condition. Each TO will show the detailed calculation steps to determine Probability of Failure within the Process Appendices.

1.1.4. PROBABILITY OF DETECTION AND ACTION P(D)

The probability that the failure mode is detected through inspection and action taken before there is a consequence. The probability failure mode *i* is detected before the consequences arise is denoted by $P(D_i)$.

The probability of detection and action has been included at this stage for completeness. Further development in this area could be considered in future iterations of the NOMs methodology; however, it is not currently included within the TOs calculations.

1.1.5. CONSEQUENCE (C)

The monetised value for each of the underlying Financial, Safety, System and Environmental components of a particular consequence e.g. Transformer Fire. 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. For example, an Asset or a particular component is only irreparably damaged once.

1.1.6. PROBABILITY OF CONSEQUENCE P(C)

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

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

Equation 2

$$where:$$

$$P(C_j) = Probability\ of\ consequence\ j\ occurring\ during\ a\ given\ time\ period$$

$$P(F_i) = Probability\ of\ failure\ mode\ i\ occurring\ during\ the\ next\ time\ interval$$

$$P(C_j|F_i) = Conditional\ probability\ of\ Consequence\ jgiven\ F_i\ has\ occured$$

$$P(D_i) = Probability\ of\ detecting\ failure\ mode\ i\ and\ acting\ before\ C_j\ materialises$$

However, where failure modes and consequences have a one-to-one mapping, this function is not required and the Probability of Failure is equal to the Probability of Consequence.

1.1.7. ASSET RISK

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

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

Equation 3

$$where:$$

$$P(C_j) = Probability\ of\ consequence\ \mathrm{j}\ occurring\ during\ a\ given\ time\ period$$

$$C_j = the\ monetised\ Consequence\ j$$

$$n = the\ number\ of\ Consequences\ associated\ with\ Asset\ k$$

1.2. LEAD ASSETS

The following sections provide background and high level deterioration mechanisms for the lead assets. Additional detail for these assets can be found in the Process Appendices.

1.2.1. CIRCUIT BREAKERS

1.2.1.1. BACKGROUND

Circuit breakers are different to other lead assets as they generally have limited condition information on an individual asset basis. To gather additional condition information on sub components which has the potential to affect the end of life modifier, would require invasive work to assess the actual condition of a particular sub component. It is undesirable to do so in the majority of situations as it would require a system outage.

Technically effective or cost justified diagnostic techniques, including continuous monitoring, are limited for use on large populations and are not applicable for deterioration modes determining the end of life of most types of existing circuit breaker. In addition, the deterioration age range is related to the equipment's environment, electrical and mechanical duty, maintenance regime and application.

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

Known deterioration modes have been determined by carrying out forensic analysis of materials and components during replacement, refurbishment, maintenance and failure investigation activities or following failures. The output of the forensic 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 TO's Defect, Failure statistics and manufacturer information. The method for mapping this knowledge to the end of life curve was presented in the functional modes and affects analysis section.

1.2.1.2. DETERIORATION

Circuit breakers are made up of a number of sub-components. These sub-components 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.

1.2.1.3. AIR-BLAST CIRCUIT BREAKER TECHNOLOGY

As Air-Blast Circuit Breaker (ABCB) families approach their end of life an assessment is made regarding the relative economic impact of replacement or refurbishment taking into account factors such as technological complexity, population size and ongoing asset management capability for the design. Since most ABCB families are no longer supported by their original equipment manufacturer, the cost and feasibility of providing parts, skilled labour and ongoing technical support must be factored into the total cost of refurbishment. For this reason, refurbishment may only be cost-effective for certain, large family types. For small families, the cost of establishing a refurbishment programme and maintaining appropriate knowledge and support will most often favour replacement.

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 (PAB) ABCBs.

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.

1.2.1.4. OIL CIRCUIT BREAKER TECHNOLOGY

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 has been developed that can be exchanged when moisture levels reach defined criteria, but at a high cost to the extent that is not economical to replace many bushings using this technology. Risk management of bushings has been achieved by routine oil sampling during maintenance, subsequent oil analysis and replacement of bushings where required. On this basis the AAL for this technology has been extended and detailed plans for replacement or refurbishment remain to be developed.

1.2.1.5. SF6 GAS CIRCUIT BREAKER TECHNOLOGY

The bulk of the Gas Circuit Breaker population (GCB) is relatively young compared to its AAL, and therefore many have not required replacement. 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 GCB population includes a large number of small 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. A more detailed asset specific strategy for replacement or refurbishment of these categories of circuit-breakers is being developed in terms of the actual number of operations and their forecast operating regime.

1.2.2. TRANSFORMERS AND REACTORS

1.2.2.1. 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 End of Life modifier. For simplicity within this section the term transformer is used to mean both transformer and reactor.

Transformers are assigned an end of life 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 end of life 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 end of life 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 end of life 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 forensic 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

1.2.2.2. TRANSFORMER AND REACTOR 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 very 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 technical 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 forensic analysis) as further understanding of deterioration mechanisms is acquired during the transformer life cycle.

1.2.2.3. INSULATING PAPER AGEING

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. Forensic 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)

1.2.2.4. 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 dissolved gas results together with forensic 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.

1.2.2.5. 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.

1.2.2.6. 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.

1.2.2.7. 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 forensic investigations from units of similar design, supported by dissolved gas results. 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.

1.2.2.8. 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.

1.2.3. UNDERGROUND CABLES

1.2.3.1. 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. These metrics only include a few condition related components since there is limited information that can be obtained on how deteriorated a cable actually is. Further condition information could be obtained by digging up and taking samples of a cable, but this is not practical, would be costly and could also cause further failures. Metrics such as the cost of repairs is taken into account when determining if a cable has reached the end of its life. While this isn't the most desirable metric from an analytical perspective, it does reflect historical practice and is justifiable from a consumer value perspective.

The factors to be taken into account when determining an end of life modifier are:

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 in terms of how much time annually a cable is running at or above its designed rating
9. Bespoke nature and issues associated with specific cable systems

1.2.3.2. DETERIORATION

End of technical life will generally be due to the deterioration of the main cable system; this may be associated with either 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.

1.2.3.3. END OF LIFE MECHANISMS AFFECTING BOTH TYPES OF CABLES

1.2.3.3.1. 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.

1.2.3.3.2. BONDING SYSTEM

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 enhanced routine maintenance.

1.2.3.3.3. COOLING SYSTEM

The life of a cable's cooling system is much shorter than the lifetime of the overall cable asset. Therefore mid-life intervention maybe 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 unique to each cable route. Loss of the cooling capacity can typically reduce circuit rating by 40%. Most problems are experienced with the original control systems which are now obsolete. 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 should be managed through maintenance to achieve the asset life of the main cable system.

1.2.3.4. FLUID FILLED CABLE END OF LIFE MECHANISMS

1.2.3.4.1. 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.

1.2.3.4.2. 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.

1.2.3.4.3. 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.

1.2.3.4.4. 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.

1.2.3.4.5. ENVIRONMENTAL CONSIDERATIONS

TOs have a statutory obligation to comply with the Water Resources Act 1991/Water Resources (Scotland) Act 2013 and to fulfil their 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 end of technical 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.

1.2.3.4.6. SOLID XLPE FILLED CABLE END OF LIFE MECHANISMS:

These cables have been installed at 132kV and 275kV for some years. There is limited service experience at 400kV. Provided high standards of manufacture and installation are available, the risk of early-life failures will be avoided. No end of life mechanism has yet been identified. The long-term deterioration mechanisms would benefit from further research and development.

1.2.4. OVERHEAD LINES

1.2.4.1. 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.

1.2.4.1. DETERIORATION

1.2.4.1.1. 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 wind ice or heat which overlead (stress) the conductor beyond its design capability. Quality of the original manufacturing could also be an issue (galvanising defects) but there is not much evidence for this in conductor condition assessment data.

1.2.4.1.2. 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.

1.2.4.1.3. FITTINGS - SPACERS, SPACER DAMPERS AND VIBRATION DAMPERS

The functional end of life of spacers, spacer dampers and vibration dampers occurs 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.

1.2.4.1.4. 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.

1.2.4.1.5. 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.

1.2.4.1.6. 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 subconductor. 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.

1.2.4.1.7. TOWERS

Corrosion and environmental stress are life-limiting factors for towers. The end of life of a whole tower is the point at which so many bars require changing that it is more economical to replace the whole tower. Degradation of foundations is another life-limiting factor for towers.

2. PROBABILITY OF FAILURE

2.1. PROCESS FOR FMEA

In order to establish an asset's likelihood of failure, Failure Modes and Effects Analysis (FMEA) is used. FMEA is a structured, systematic technique for failure analysis. It involves studying components, assemblies and subsystems to identify failure modes, their causes and effects. The use of FMEA in this context aims to examine the effectiveness of the TOs' current risk management by considering these key elements relating to potential failure modes:

- What are the effects or consequences of the failure mode?
- How often might the failure mode occur?
- How effective is the current detection?
- How effective are the interventions for the failure mode?

Many assets in transmission networks are asset systems (combinations of assets). FMEA views the asset as an assembly of 'items', being the part of the asset that performs a defined function. In terms of 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.

To determine risk it is necessary to identify the consequences of each potential failure event. The addition of consequence (criticality) considerations to FMEA leads to Failure Modes, Effects and Criticality Analysis (FMECA).

Some illustrative guidance is provided by BS EN 60812 and section 5.2.5 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.

In a highly-meshed system, such as a transmission network, consideration of system effects becomes paramount. Unfortunately, traditional FMECA analysis (as described in BS EN 60812) does not enable such analysis, relying as it does on non-tradeable "criticality scores". To comply with the NOMs requirements, a much more comprehensive system of consequence evaluation must be derived, leading to a transparent,

objective and tradeable measure of risk.

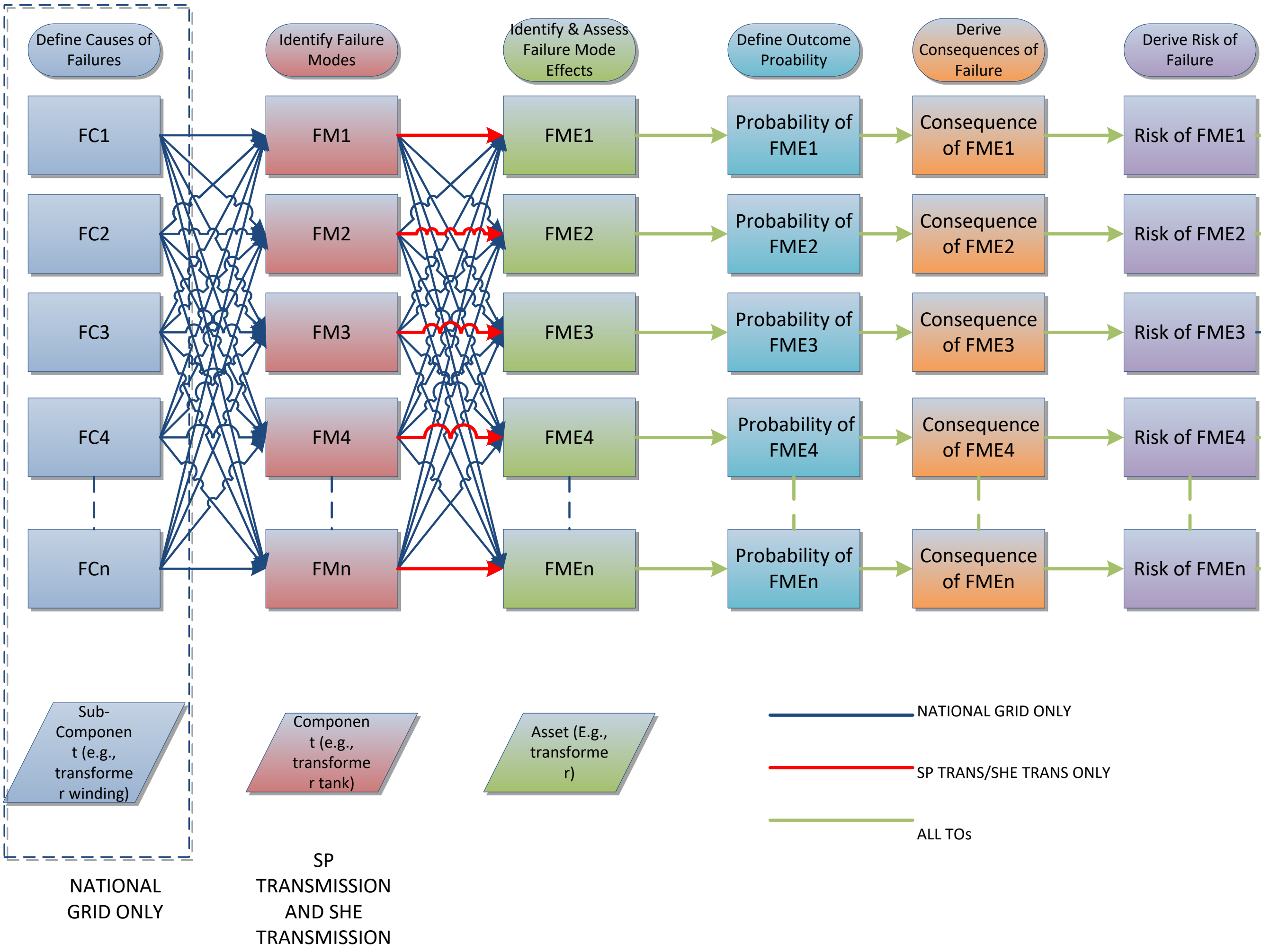


Figure 2 shows the high level mapping of Failure Modes for NGET and SPT/SHE-T which is further expanded in the Process Appendices.

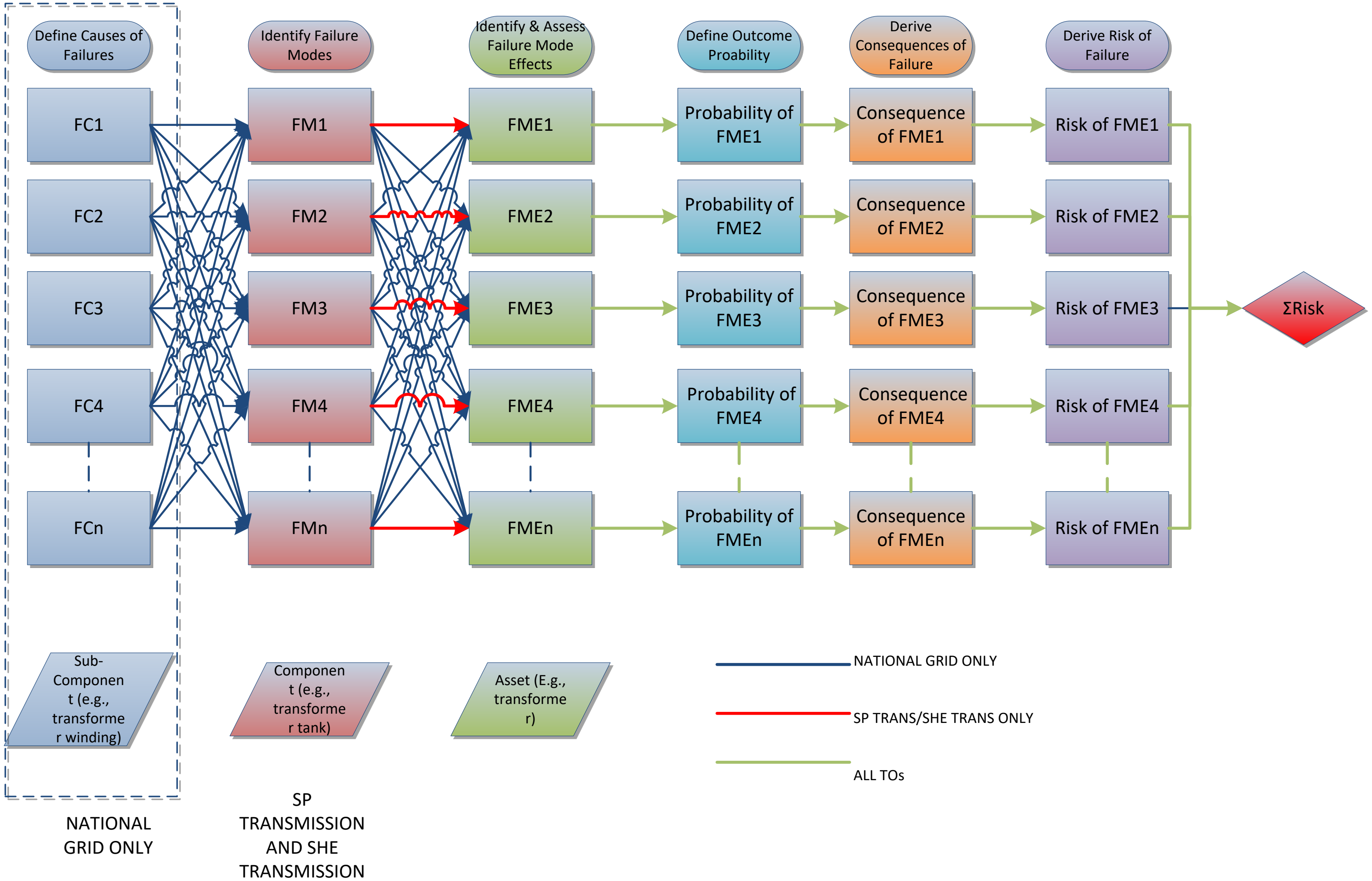

Define Causes of Failures
Identify Failure Modes
Identify & Assess Failure Mode Effects
Define Outcome Proability
Derive Consequences of Failure
Derive Risk of Failure
FC1
FC2
FC3
FC4
FCn
FM1
FM2
FM3
FM4
FMn
FME1
FME2
FME3
FME4
FMEn
Probability of FME1
Probability of FME2
Probability of FME3
Probability of FME4
Probability of FMEn
Consequence of FME1
Consequence of FME2
Consequence of FME3
Consequence of FME4
Consequence of FMEn
Risk of FME1
Risk of FME2
Risk of FME3
Risk of FME4
Risk of FMEn
ΣRisk
Sub-Component (e.g., transformer winding)
Component (e.g., transformer tank)
Asset (E.g., transformer)
NATIONAL GRID ONLY
SP TRANS/SHE TRANS ONLY
ALL TOs
NATIONAL GRID ONLY
SP TRANSMISSION AND SHE TRANSMISSION

Figure 2

2.2. UNDERSTANDING FAILURE CAUSE TYPES ON TO ASSETS

There are five basic underlying types of failure:

1. Time based failure (Potential to Functional failure)
   The patterns of failure are predictable with an interval between initiation (potential) to failure. Inspection activities may be available to identify these. These are represented within the model with an earliest and latest expected onset of the failure based on the time that has elapsed following the last intervention (for example, maintenance activity) which addresses the particular failure

2. 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 asset types may have a known number of operations and are represented in the model by the number of expected operations to failure since the last intervention that addresses the particular failures

3. Random failure
   These failure modes will have a constant failure rate, usually expressed as a percentage per annum for the population

4. Hidden failure
   These are failure modes that cannot be detected but which exist and may require the occurrence of a failure in order for them to be revealed. Initially these can only be addressed through reactive interventions. They may be specific to the asset but may apply to a family of assets as a type defect or a deterioration mode that had not previously been understood

5. Asset specific failure
   Some assets are not able to be influenced by maintenance. For example a design weakness may become apparent for a particular family of assets.

To avoid unnecessary levels of analysis, section 5.2.4 of BS EN 60812 recommends that the most likely causes for each failure mode should be identified. Therefore, rather than identifying every single possible cause for all failure modes, the level of detail should be reflective of the failure mode effects and their severity. The more severe the effects the more accurate the identification and description to prevent unnecessary effort to failure causes with little effect. The failure cause may usually be determined from analysis of failed failures, test units or expert opinion.

2.3. FAILURE MODES

There are a number of potential reasons for an asset to fail. These can lead to many different failures modes, which in turn lead to an event.

Every asset will have many different failures modes, for example consideration of the range of failure modes associated with a circuit breaker may resemble Figure 3 (purely illustrative and not to scale).

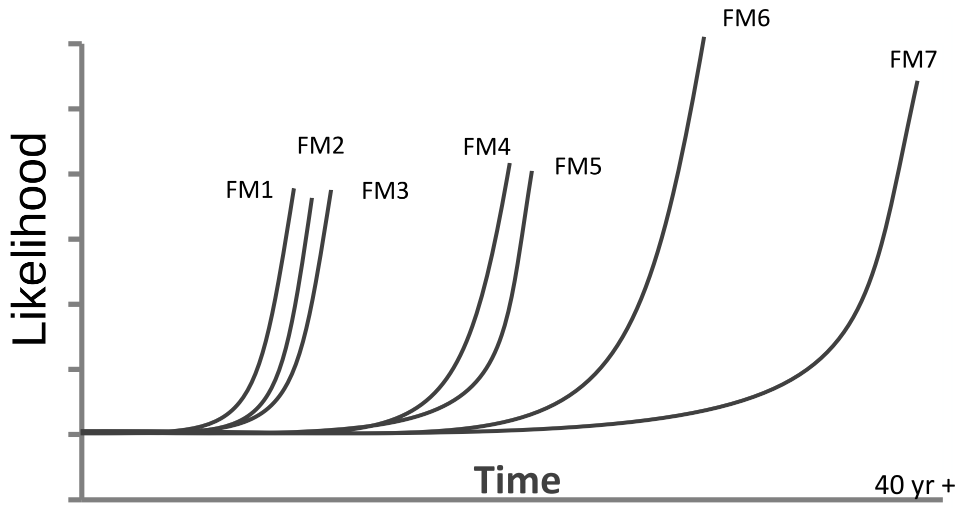


Figure 3

Examples of these failure modes might include:

FM1	Failure to trip
FM2	Leaks
FM3	Overheat
FM4	Failure to close
FM5	Loss of lubrication
FM6	Flashover
FM7	Metal fatigue/corrosion

Table 2

The level of detail in the analysis (and the number of relevant failure modes) is an important consideration. Section 5.2.2.3 of BS EN 60812 provides useful guidance in this area and recognises that the number of failure modes for consideration will be influenced by previous experience; less detailed analysis may be justified from a system based on a mature design, with good reliability, maintainability and safety record. In addition, the requirements of the asset maintenance and repair regime may be a valuable guide in determining the necessary level of detail.

2.3.1. UNDERSTANDING FAILURE MODES AND HOW INTERVENTIONS IMPACT ASSET RISK

Figure 4 shows a simplified and purely illustrative example of an asset that has 2 failure modes (FM1 and FM2). The blue line represents the asset's risk position with time:

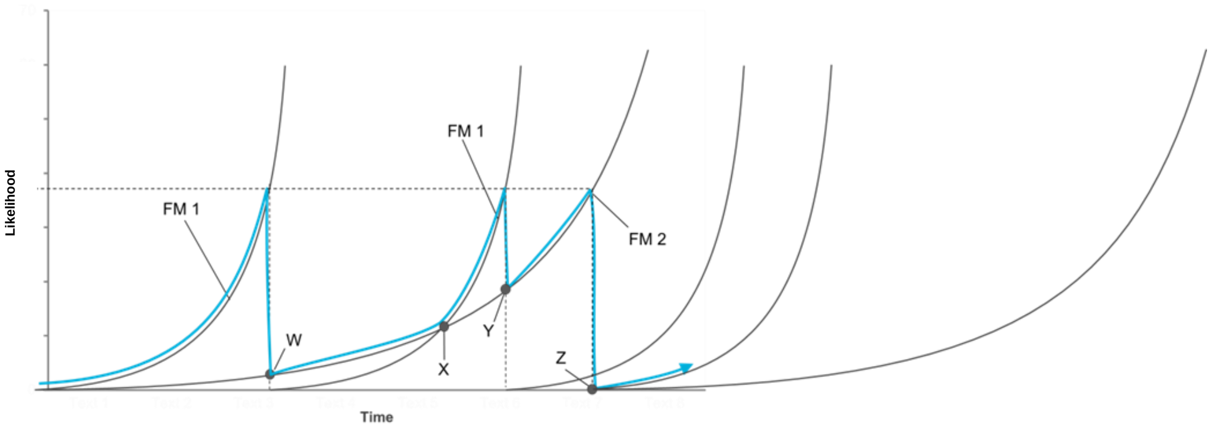


Figure 4

An intervention addresses one or more failure modes, either resetting or partially resetting that failure mode however others are left unchanged.

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

The asset risk then drops down onto FM2's curve at point 'W' as FM1 has effectively reset and so deterioration progresses along the degradation curve for 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 in 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'.

In terms of identifying when to carry out an intervention a number of factors need to be considered in addition to the asset risk. For example, 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.

2.3.2. DETECTING FAILURE MODES

There are a number of techniques that can be used to detect certain failure modes.

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

2.3.3. EVENTS RESULTING FROM A FAILURE MODE

Each failure mode may result in one or more events. These are categorised in a hierarchy of failure mode events in terms of the impact.

The events are categorised in a hierarchy of failure mode consequences in terms of the impact of failure which are comparable across the asset types, an example of which is shown in Table 4.

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

Table 4

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	Class of 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	Major
					17 - Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement	Major
					14 - Alarm + Trip + Internal Damage	Significant
					05 - Unwanted Alarm + Trip	Minor

Table 5

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 simply repaired.

Table 6 shows an example of the events resulting from transformer failure modes. Note that these are example times, return to service times may vary for individual assets and TOs depending on, for example, the nature of the failure, availability of spare parts, resourcing issues or existing system constraints.

Event	Class of Event	Unplanned Return to Service
01 - No Event	No Event	0
02 – Environment Noise	Defect	1
03 - Reduced Capability	Defect	1
04 - Alarm	Defect	1
05 - Unwanted Alarm + Trip	Minor	1
06 - Transformer Trip	Minor	1
07 - Reduced Capability + Alarm + Trip	Minor	1
08 - Fail to Operate + Repair	Minor	1
09 - Reduced Capability + Alarm + Loss of Voltage Control + Fail to Operate	Significant	1
10 - Overheating (will trip on overload)	Significant	1
11 - Cross Contamination of Oil	Significant	1
12 - Alarm + Damaged Component (Tap Changer) No Trip	Significant	5
13 - Alarm + Trip + Damaged Component (Tap Changer)	Significant	30
14 - Alarm + Trip + Tx Internal Damage	Significant	30
15 - loss of oil into secondary containment	Significant	15
16 - Alarm + Trip + Damage + State Requiring Replacement (Asset Replacement)	Major	180
17 - Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement	Major	180
18 - Alarm + Trip + Disruptive Failure + External Damage (danger) + Replacement+ Transformer Fire	Major	180

Table 6

2.4. PROBABILITY OF FAILURE

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 the component failure rates, and consequently failure rate of the failure mode under consideration, in most cases 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:

- Data from the component life testing
- Available databases of failure rates
- Field failure data
- 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.

It is recognised that each TO will have different asset profiles in different operating environments. Different operating regimes and historic maintenance practises will therefore result in different PoF outcomes. Furthermore, differences in recording and classification of historic performance data may mean that PoF rates are not directly comparable, and different methodologies may need to be employed to determine the asset PoF. These methodologies are described in more detail in the Process Appendices.

The failure modes and effects analysis defines an end of life curve for each asset. It is recognised that some of these predicted deterioration mechanisms have yet to present themselves and were based on knowledge of asset design and specific R&D into deterioration mechanisms. In summary the following sources of data were utilised:

- Results of forensic evidence
- Results of condition assessment tests
- Results of continuous monitoring
- Historical and projected environmental performance (e.g. oil loss)
- Historical and projected unreliability
- Defect history for that circuit breaker family.

2.4.1. FACTORS THAT MAY INFLUENCE THE FAILURE MODE'S PROBABILITY OF FAILURE

2.4.1.1. DIFFERENTIATORS

There may be factors that change the shape of the deterioration curves. Examples of these differentiators may include:

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

2.4.1.2. MODIFIERS

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.

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 different point of progression along the curve due to specific location/operation 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.

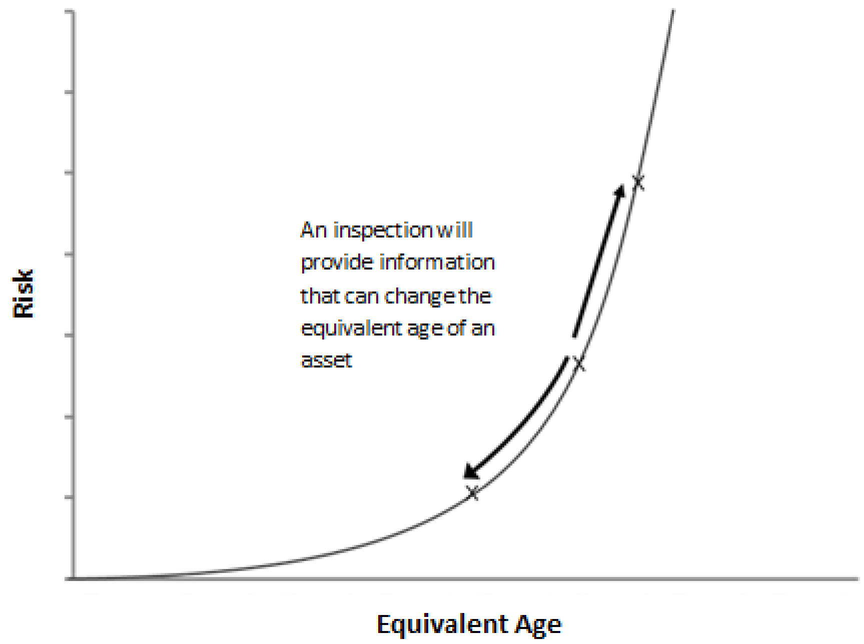


Figure 5

2.4.2. MAPPING END OF LIFE MODIFIER TO PROBABILITY OF FAILURE

End of life (EOL) can be defined as when the condition related probability of failure becomes unacceptable. It may be difficult to define unacceptable PoF, and indeed it may vary from asset to asset. For every individual asset an EOL Modifier is determined. The EOL Modifier will then need to be translated into an EOL probability of failure.

The method for translating the EOL Modifier into a probability depends on the asset type. Asset types may need their EOL Modifier translated into an Equivalent Age. The Equivalent Age can then be used to determine probability of failure for a specific end of life failure mode.

The method described here generates an expected end of life modifier function, which is used to map between the EOL modifier and an Equivalent Age. The following paragraph describes how this mapping function can be produced.

The mapping function cannot be generated using historical data points, because the data is right censored due to the fact that many assets have not completed a whole lifecycle. Judgement needs to be applied about how the health of an asset is expected to deteriorate through its life. The end of life modifier is then mapped to an equivalent age, which is used by FMEA to determine the conditional probability of failure for the corresponding end of life failure mode.

2.4.3. CALCULATING PROBABILITY OF FAILURE

As described above the probability of failure curve is based in terms of 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 a cumulative distribution function *F(t)* can be constructed.

In order to calculate the end of life probability of failure associated with a given asset, the asset will need to be assigned an end of life modifier. This end of life 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 as well as forensic examination of decommissioned assets may also be taken into account when assigning an end of life modifier. Using the end of life modifier an asset's equivalent age can be determined and then mapped onto a specific point on the probability of failure curve.

Specific calculations on determining the End of Life Modifiers are found in the Process Appendices.

2.4.4. FORECASTING PROBABILITY OF FAILURE

Future probability of failure 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 this curve along usually at the rate of one year per year. Figure 6 illustrates the probability of failure for an asset highlighting the probability of failure at an equivalent age of 80.

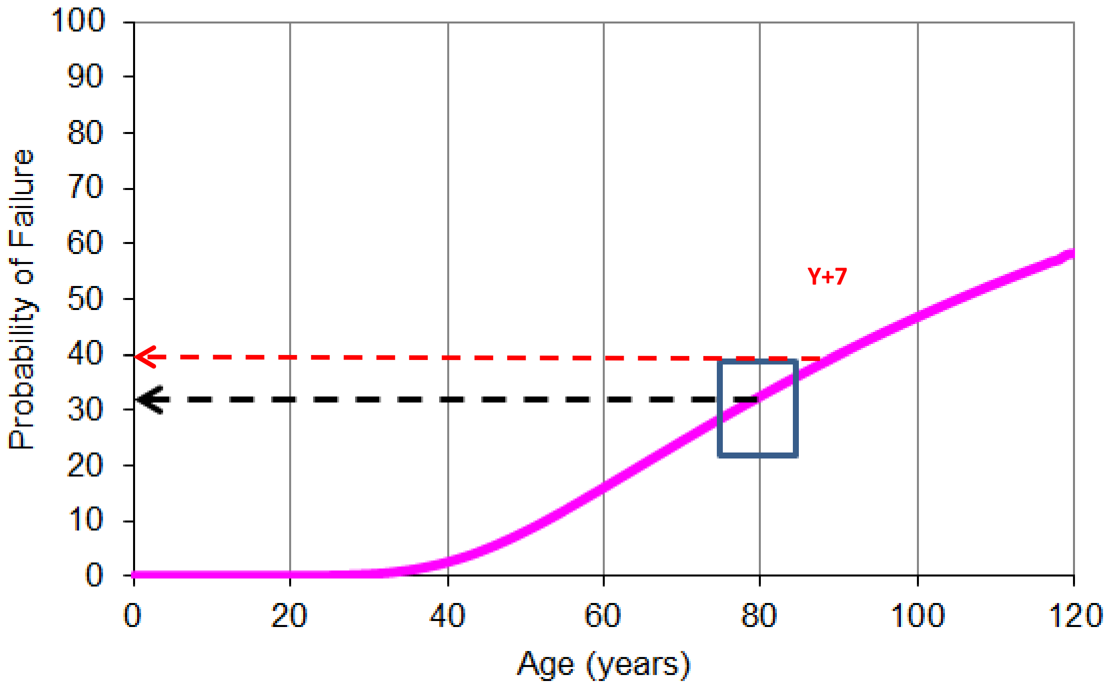
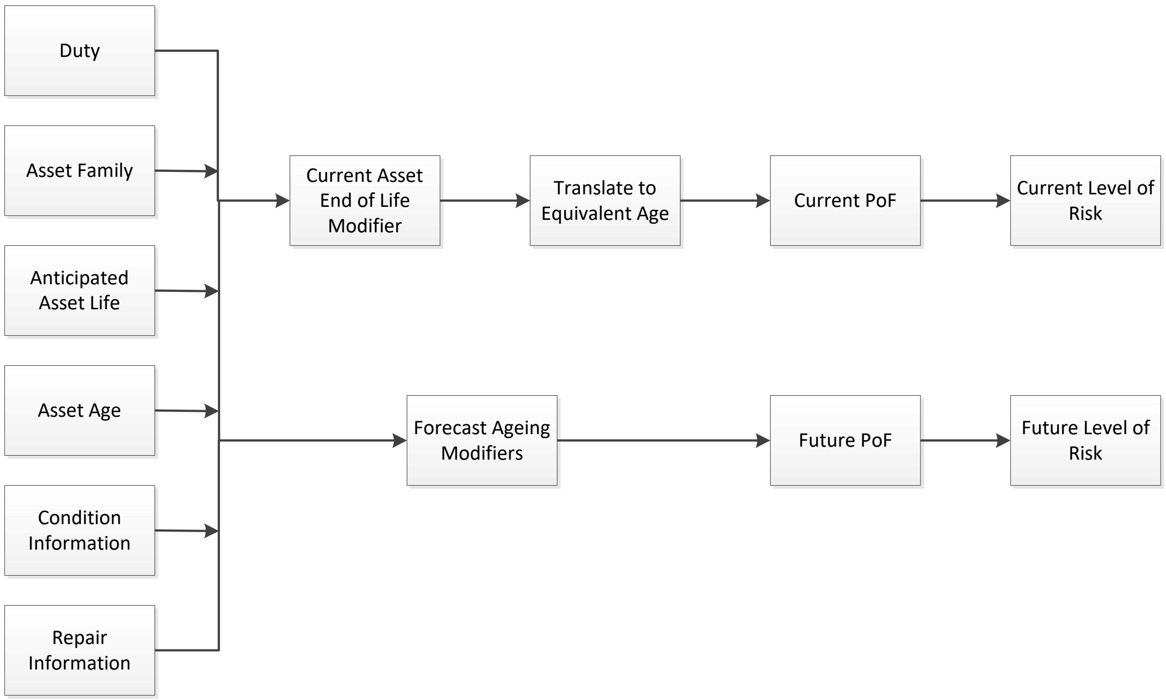


Figure 6

The forecast probability of failure in future years can then be obtained by following the curve along. 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.

2.4.5. HIGH LEVEL PROCESS FOR DETERMINING END OF LIFE PROBABILITY OF FAILURE

The process illustrated below will be used to determine the probability of failure of each asset. In particular the end of life modifier will need to be translated that will be determined in Process Appendices. This will be done by translating through an equivalent age step, so that the appropriate end of life curve can be used to determine the probability of an asset having failed.



This process is shown in more detail for each asset type within the Process Appendices.

3. CONSEQUENCE OF FAILURE

The consequences of the failure may fall into four categories:

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

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 consequence are specific to the asset and also to its physical location.

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 will be agreed with Ofgem.

Each TO states clearly which failure modes have been included in the analysis and explains why the chosen failure modes are considered appropriate for the analysis, as detailed in the technical appendices to this methodology. The appendices also detail how the Probability of Failure (PoF) has been determined and how modifiers have been applied to determine the asset PoF.

BS EN60812 disaggregates systems into their component parts and assesses the probability of functional failures of each component and the consequences of such functional failures, then aggregates 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 functional failure of a component is much greater than value of the risk represented by the functional failure of that component, because either the probability of functional failure of a component or the consequence of failure of a component is insufficiently large.

Evidential and supporting data, suitable for FMECA analysis is usually imperfect. 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 FMECA therefore requires engineering judgement, 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 Direction 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. By definition, 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 a TO (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

It is the aim of this section to provide quantified view in the terms of a monetised consequence.

In taking the below detailed approach 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.

The monetisation does not correspond to the actual costs that will be incurred. The data used in the models attempts to approach the correct orders of magnitude to avoid confusion it does not however, guarantee this and can only be treated as abstract.

3.1. SYSTEM CONSEQUENCE

The system consequence of a failure mode of an asset is a measure of the assets importance in terms of its function to the transmission system and 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 System Operator costs. Regardless of who initially pays these costs they are ultimately born by electricity consumers. Customer costs are incurred as a result of the disconnection of customers supplied directly or indirectly (via a distribution network) connected by the transmission system. The cost for demand disconnections are 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 System Operator. The second category of costs are those that the System Operator 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 National Electricity Transmission System Security and Quality of Supply Standard (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 Transmission Owners 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 7 represents this philosophy.

This approach is further influenced by other considerations such as the geographical location of the assets in question i.e. which Transmission Owner 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.

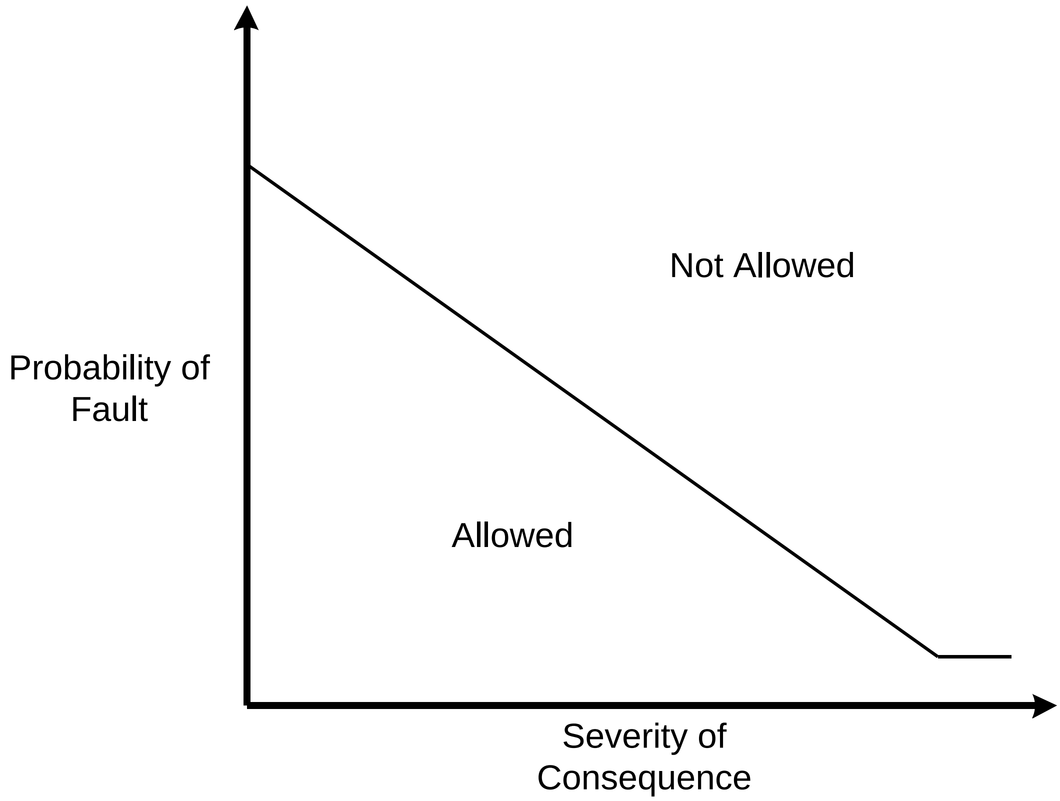


Figure 7

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 SO 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 in duration. 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.

3.1.1. QUANTIFYING THE SYSTEM RISK DUE TO ASSET FAULTS AND 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. 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 three sections. All three share a common structure that can be expressed by Equation 4.

$$cost\ of\ consequence\ = probability\ \ x\ duration\ x\ size\ x\ cost\ per\ unit$$

Equation 4

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

3.1.2. 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 is defined, X;

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

Equation 5

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 X values greater than the lowest X value; $X_{min}=min(X)$. 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. There is a significant risk that cascade tripping of remaining circuits due to overloading will result. For this reason if $X_{min} > 4$ for an asset it will be treated as $X_{min} = 4$ for the purposes of calculating P_{oc} and D.

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 6

Intuitively $M_1 = 1$, and M_Z scales with N. Figure 8 illustrates an example of how M_Z is calculated with three customer sites (M_3):

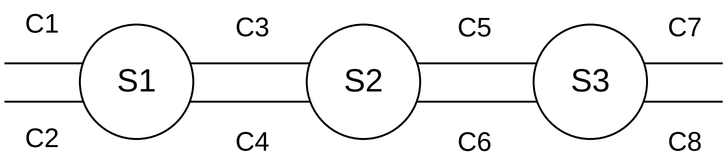


Figure 8

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 amount 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 7

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 8

Therefore M_3 is equal to 2.

3.1.3. 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 7.

Probability	Symbol	Determination of Value
Coincident outage	P_o	TO statistics on planned unavailability of circuits
Damage to another circuit	P_d	TO historical experience of explosive/incendiary failure modes
Maloperation of another circuit	P_m	TO statistics on protection maloperation
Coincident fault to another circuit	P_f	TO fault statistics
Overloading of remaining circuit	P_l	See below

Table 7

The probabilities P_o, P_d, P_m and P_f are determined separately by each TO according to their own methodology outlined in Licensee Specific Appendices. The calculation of P_l, is common with two different equations dependent upon the nature of the customer sites at risk of disconnection:

$$\text{For } MW_{GTEC} - MW_D \geq 0\ ,\ P_l = 0.52$$

Equation 9

$$\text{For } MW_{GTEC} - MW_D < 0\ ,\ P_l = 0.88$$

Equation 10

Where MW_{GTEC} is the sum of TEC values of generators connected to the sites at risk (minus any generators that do not receive disconnection payments due to design variations) and MW_D is the total adjusted winter peak demand connected to the sites at risk. P_l is only relevant for assets with $X_{min} \geq 4$.These values of P_l are derived from annual whole system data in the following fashion.

For customer connection sites with adjusted generation capacity greater than peak demand (equation 9) the local capacity will usually be designed to carry the maximum credible local generation output under N-2 conditions. For a four circuit group this will mean each circuit will be designed to carry 50 % of this maximum credible output. If a four circuit group experiences a N-3 scenario the remaining circuit will overload and trip if the loading exceeds 50% of the maximum credible generation output of the site. Therefore P_l is the proportion of settlement periods during a year that generation exceeds 50% of the credible maximum generation output for the sites in question. In order to derive and estimate for this proportion that can be applied across the entire GB system the credible maximum generation output of the entire system can be approximated by multiplying the TEC of every generator in the system by its NETS SQSS generation scaling factor and then dividing by 2 to give an equivalent N-3 capacity for a generic four circuit group. This equivalent capacity can then be compared to actual metered whole system generation for each ½ hour period of the year to establish what proportion of the year the system's generation is above the equivalent rating. Using the TEC register and full year metered generation data for 2015 the sum of all generator's TEC multiplied by their SQSS scaling factor is 54089 MW. Half of this value is 27044 MW and system generation exceeded 27.044 GW for 52% of settlement periods to give a P_l of 0.52.

For customer sites with peak demand greater than generation capacity (equation 9) the local capacity will be designed to carry access period peak demand, the peak system demand in between clock change dates during which maintenance access is scheduled, for N-2 conditions. Historically, the whole system access period peak demand is 85% of winter peak demand. Therefore each circuit will be designed to carry 50% of access period demand, or on average 42.5% of winter peak demand of the site. If a four circuit group experiences a N-3 scenario the remaining circuit could overload and trip if the loading exceeds 42.5% of the winter peak demand of the site. Therefore this value of P_l represents the proportion of settlement periods during the year that total system demand is in excess of 42.5% of total system winter peak demand. Using full year metered generation data for 2015 the peak demand is 51800 MW. The assumed capacity is 0.425 of this value or 22015 MW. Whole system demand exceeded 22.015 GW for 88% of settlement periods to give a P_l of 0.88.The probabilities in Table 7 can be combined to create a probability tree for each value of X_{min} between 0 and 4. Below are the resulting equations for P_{oc}, the probability of disconnection.

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

Equation 11

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

Equation 12

$$\text{For } X_{min} = 2,\ P_{oc} = P_d^2 + 2P_dN_dP_o + 2P_dN_dN_oP_m + 2P_dN_dN_oN_mP_f + N_d^2P_oP_m + N_d^2P_oN_mP_f + N_d^2N_oP_mP_f + N_d^2N_oN_mP_f^2$$

Equation 13

$$\text{For } X_{min} = 3,\ P_{oc} = P_d^2P_o + P_d^2N_oP_m + P_d^2N_oN_mP_f + P_d^2N_oN_mN_fP_l + 2P_dN_dP_oP_m + 2P_dN_dP_oN_mP_f + 2P_dN_dP_oN_mN_fP_l + 2P_dN_dN_oP_mP_f + 2P_dN_dN_oP_mN_fP_l + 2P_dN_dN_oN_mP_f^2 + 4P_dN_dN_oN_mP_fN_fP_l + N_d^2P_oP_mP_f + N_d^2P_oP_mN_fP_l + N_d^2P_oN_mP_f^2 + 2N_d^2P_oN_mP_fN_fP_l + N_d^2N_oP_mP_f^2 + 2N_d^2N_oP_mP_fN_fP_l + N_d^2N_oN_mP_f^3 + 3N_d^2N_oN_mP_f^2N_fP_l$$

Equation 14

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 Figure 9, the probability tree diagram for the most complex of the four cases, $X_{min} = 3$.

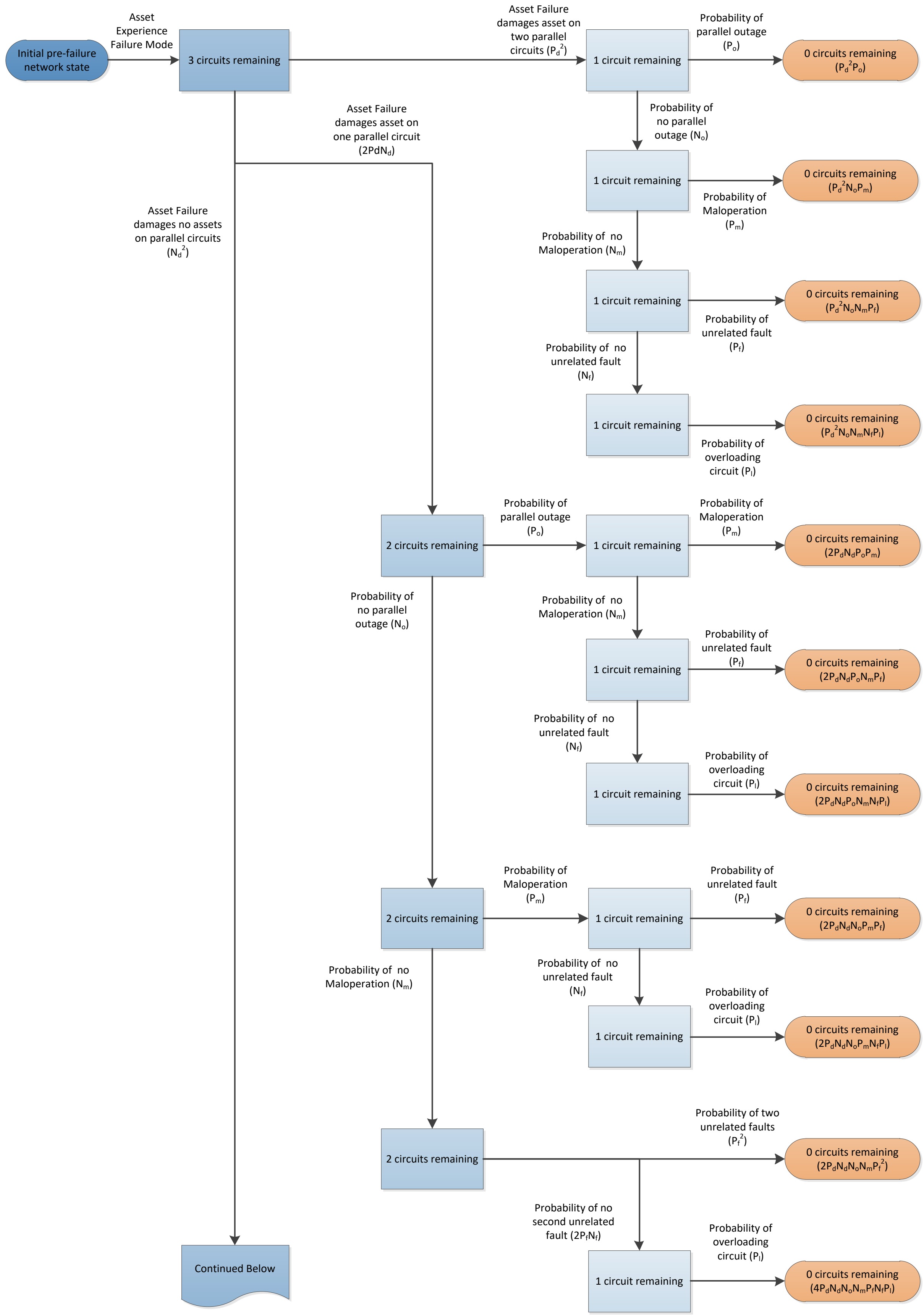

Initial pre-failure network state
Asset Experience Failure Mode
3 circuits remaining
Asset Failure damages asset on two parallel circuits (P_d^2)
1 circuit remaining
Probability of parallel outage (P_o)
0 circuits remaining ($P_d^2P_o$)
Probability of no parallel outage (N_o)
1 circuit remaining
0 circuits remaining ($P_d^2N_oP_m$)
Probability of Maloperation (P_m)
Probability of no Maloperation (N_m)
1 circuit remaining
0 circuits remaining ($P_d^2N_oN_mP_f$)
Probability of unrelated fault (P_f)
Probability of no unrelated fault (N_f)
1 circuit remaining
0 circuits remaining ($P_d^2N_oN_mN_fP_l$)
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 ($2P_dN_dP_oP_m$)
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 ($2P_dN_dP_oN_mP_f$)
Probability of no unrelated fault (N_f)
1 circuit remaining
Probability of overloading circuit (P_l)
0 circuits remaining ($2P_dN_dP_oN_mN_fP_l$)
2 circuits remaining
Probability of Maloperation (P_m)
1 circuit remaining
Probability of unrelated fault (P_f)
0 circuits remaining ($2P_dN_dN_oP_mP_f$)
Probability of no Maloperation (N_m)
Probability of no unrelated fault (N_f)
Probability of overloading circuit (P_l)
1 circuit remaining
0 circuits remaining ($2P_dN_dN_oP_mN_fP_l$)
2 circuits remaining
Probability of two unrelated faults (P_f^2)
0 circuits remaining ($2P_dN_dN_oN_mP_f^2$)
Probability of no second unrelated fault ($2P_fN_f$)
Probability of overloading circuit (P_l)
1 circuit remaining
0 circuits remaining ($4P_dN_dN_oN_mP_fN_fP_l$)
Continued Below

Figure 9

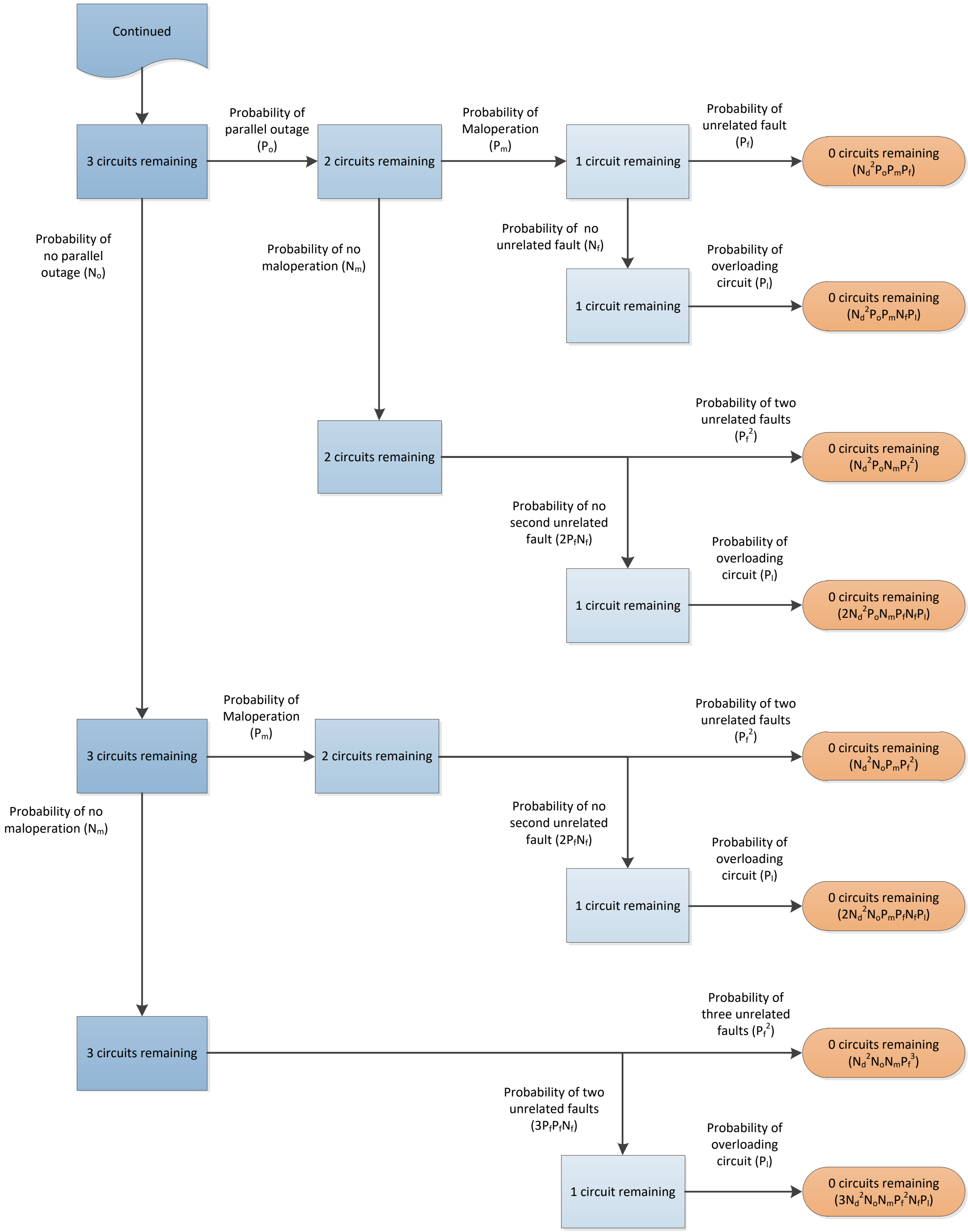

Continued
3 circuits remaining
Probability of parallel outage (P_o)
2 circuits remaining
Probability of Maloperation (P_m)
1 circuit remaining
Probability of unrelated fault (P_f)
0 circuits remaining ($N_d^2P_oP_mP_f$)
Probability of no unrelated fault (N_f)
1 circuit remaining
Probability of overloading circuit (P_l)
0 circuits remaining ($N_d^2P_oP_mN_fP_l$)
Probability of no parallel outage (N_o)
Probability of no maloperation (N_m)
2 circuits remaining
Probability of two unrelated faults (P_f^2)
0 circuits remaining ($N_d^2P_oN_mP_f^2$)
Probability of no second unrelated fault ($2P_fN_f$)
1 circuit remaining
Probability of overloading circuit (P_l)
0 circuits remaining ($2N_d^2P_oN_mP_fN_fP_l$)
3 circuits remaining
Probability of Maloperation (P_m)
2 circuits remaining
Probability of two unrelated faults (P_f^2)
0 circuits remaining ($N_d^2N_oP_mP_f^2$)
Probability of no maloperation (N_m)
Probability of no second unrelated fault ($2P_fN_f$)
1 circuit remaining
Probability of overloading circuit (P_l)
0 circuits remaining ($2N_d^2N_oP_mP_fN_fP_l$)
3 circuits remaining
Probability of three unrelated faults (P_f^2)
0 circuits remaining ($N_d^2N_oN_mP_f^3$)
Probability of two unrelated faults ($3P_fP_fN_f$)
1 circuit remaining
Probability of overloading circuit (P_l)
0 circuits remaining ($3N_d^2N_oN_mP_f^2N_fP_l$)

Figure 10

3.1.4. 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 8.

Duration	Symbol	Determination of Value
Duration of failure mode unavailability	D_{fm}	TO experience of failure durations
Outage restoration time	D_o	TO statistics on planned unavailability of circuits
Circuit damage restoration time	D_d	TO historical experience of explosive/incendiary failures of failure mode
Protection mal-operation restoration time	D_m	TO statistics on protection maloperation
Unrelated fault restoration time	D_f	TO fault statistics
Circuit overload restoration time	D_l	TO historical experience of overload trips

Table 8

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 Licensee 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 15

$$\text{For } X_{min} = 1,\ D = [min(D_{fm},D_o)P_o + min(D_{fm},D_d)P_d + min(D_{fm},D_f)P_f + min(D_{fm}, D_m)P_m] / P_{oc}$$

Equation 16

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

Equation 17

$$\text{For } X_{min} = 3,\ P_{oc} = [min(D_{fm},D_d,D_o)P_d^2P_o + min(D_{fm},D_d,D_m)P_d^2N_oP_m + min(D_{fm},D_d,D_f)P_d^2N_oN_mP_f + min(D_{fm},D_d,D_l)P_d^2N_oN_mN_fP_l + min(D_{fm},D_d,D_o,D_m)P_dN_dP_oP_m + min(D_{fm},D_d,D_m,D_f)P_dN_dN_oP_mP_f + min(D_{fm},D_d,D_f)P_dN_dN_oN_mP_fP_f + min(D_{fm},D_d,D_f,D_l)P_dN_dN_oN_mP_fN_fP_l + min(D_{fm},D_o,D_m,D_f)N_dN_dP_oP_mP_f + min(D_{fm},D_m,D_f)N_dN_dN_oP_mP_fP_f + min(D_{fm},D_f)N_dN_dN_oN_oP_fP_fP_f + min(D_{fm},D_f,D_l)N_dN_dN_oN_oN_fP_fP_fP_l]/ P_{oc}$$

Equation 18

3.1.5. 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. It is expressed firstly in terms of the total Transmission Entry Capacity (TEC) in MW of generators at all sites disconnected minus the TEC of those generators that do not receive disconnection payments, MW_{GTEC}. 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 9. These are demand sites of particular importance in terms of economic or public safety impact. Not included are any sites for which the disconnection risks are considered High Impact Low Probability (HILP) events.

The lists of sites that belong to the categories outlined in Table 9 are deemed sensitive and thus are not included here. The selection criteria and sources for the lists of sites can be found in the individual Licensee Specific Appendices. The costs of disconnection per site, per hour were calculated by collecting as much publically available information as possible on the costs of historic disconnection events of comparable infrastructure sites across the developed world. These costs per minute or per event were converted into current sterling prices via 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=31000	-
Economic Key Point	S_E	V_E = 24000	-
Particularly sensitive COMAH sites	S_C	-	V_C = 16970000

Table 9

The final component of the risk cost, the per unit cost, is separately defined for the three above quantities of customer loss. Value of Lost Load (*VOLL*) in £/MWh is the same RPI indexed value as that used in the RIIO-T1 energy not supplied incentive, £16000/MWh based on 09/10 prices.

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 System Operator.

$$\text{For } D \leq 1.5\text{h}, \; G_c = 0.5MW_{GTEC}DC_{SBP}$$

Equation 19

$$\text{For } 1.5\text{ h} < D \leq 24\text{h}, \; G_c = 0.5MW_{GTEC}(1.5C_{SBP} + \{D-3\}C_{SMP})$$

Equation 20

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

Equation 21

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} and C_{TNUoS} is the average 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, $G_R = DC_{SMP}(0.42MW_{GTEC} - 0.62MW_D)$

Equation 22

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

Equation 23

For $G_R \geq 0$, $G_{R^*} = G_R$

Equation 24

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

Equation 25

This cost reflects the expense of the System Operator constraining on generation to replace that lost by the disconnection of generation. The equation multiples 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_{GTEC}, 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 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 two 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 60D.

$$V = 60D(V_T S_T + V_E S_E) + V_C S_C)$$

Equation 26

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 27.

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

Equation 27

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 4 circuits. These assets will have material risks for one of the next two elements of system consequence.

* In the future it may be possible to vary VOLL with the type of load lost but this is not included in the current methodology.

3.1.6. 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 in 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 System Operator on an annual basis. The System Operator 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 cost of operation for the boundary. B_y is then calculated as follows:

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

Equation 28

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

Equation 29

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

Equation 30

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 31.

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

Equation 31

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 31 can be illustrated with the example of B6, the boundary between the SPT and NGET areas. There are currently four circuits that make up this boundary. If a failure of a tower carrying two of these circuits occurs then both circuits will be unavailable until the failure has been rectified, Y = 2 for this failure. The boundary will be N-2 depletion until the failure is rectified and on average will spend some proportion, P_{Y+1}, of the duration of failure at a N-3 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_2 by (1- P_{Y+1}), the proportion of time that the boundary is at N-2 depletion. Then B_3 is multiplied by the proportion of time that the boundary will spend at N-3 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 tower, D_{fm}. This gives us the total expected boundary constraint for the failure mode of the tower.

3.1.7. REACTIVE COMPENSATION

The third methodology calculates the cost impact of having reactive compensation unavailable due to a fault or failure of such an asset. 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 SO must pay to buy the same service from generators. Therefore Equation 32 Is used to calculate the reactive compensation system risk cost, RRC, of an asset failure mode:

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

Equation 32

R_F is the requirement factor of the compensation or the proportion of the year that the compensation is required. D_{fm} is the duration of unavailability due to the asset failure mode. Q is the capacity of the asset in MVAr and C_{MVArh} is the average cost of procuring of MVAr from generation sources.

R_F is assigned to each reactive compensation lead asset on the follow basis:

R_F = 0.25 for a Summer only requirement

R_F = 0.75 for a Summer, Spring and Autumn requirement

R_F = 1 for year round requirement

C_{MVArh} will be calculated by taking an annual sum of all costs of generators to absorb MVArs including BM 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.

3.2. SAFETY CONSEQUENCE

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 does happen society as a whole incurs a cost. The aim of this part of the methodology is to therefore capture the safety risks that deteriorating assets present to individuals who are exposed to their effects and the associated cost. In general the safety risk for an individual asset can be expressed as shown below:

$$Safety\ Risk = Probability\ of\ Failure\ Mode\ Effect\ \times Safety\ Cost$$

Equation 33

Where:

- **Probability of Failure Mode Effect** – represents the likelihood of different effects occurring as a result of assets failing
- **Safety Cost** – represents the safety related costs associated with asset failure

For an individual asset the general expression for 'Safety Cost' is:

$$Safety\ Cost = Probability\ of\ Injury\ \times Cost\ of\ Injury\ \times Exposure$$

Equation 34

The terms in the expression hold the following meanings:

- **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
- **Exposure** – modifier to reflect the number of people who are exposed to the effects of an asset failure

In reality 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:

$$Safety\ Cost_i = \sum_j Probability\ of\ Injury_{j,i}\ \times Cost\ of\ injury_j\ \times\ Exposure_j$$

Equation 35

Where:

i	=	Failure Mode Effect
j	=	Injury Type

The total 'Safety Risk' associated with the asset can therefore be expressed as shown in the below equation.

$$Safety\ Risk = \sum_{i} PoE_i \times Safety\ Cost_i$$

Equation 36

Where:

PoE = Probability of Failure Mode Effect

3.2.1. FAILURE MODE EFFECT & PROBABILITY OF FAILURE MODE EFFECT

The failure mode effect represents the possible effects that TOs consider as a result of failure and the probability of failure mode effect represents its likelihood of occurrence. The effects that are considered by the TOs and the calculation of their likelihood is described in the Process Appendices.

3.2.2. INJURY TYPE & PROBABILITY OF INJURY

Individuals can sustain varying degrees of injury as a result of an asset failure. The TOs propose to categorise the severity of injury into the following types:

1. Minor Injury
2. Lost Time Injury
3. Major Injury
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 types categories for a particular 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).

3.2.3. COST OF INJURY

Fixed costs will be assigned to the different injury types considered and they will apply to all assets considered in the methodology. The costs assigned to different injury types consider the following factors:

- Criminal fines
- Civil damages
- Legal costs
- Investigation costs
- Additional mitigations
- Societal loss
- Productivity losses

Each of these factors is discussed in the proceeding sections. The TOs anticipate that the 'Cost of Injury' will be calculated as below:

$$Cost\ of\ Injury_j = \sum CF + CD + LC + IC + AM + SL + PL$$

Equation 37

Where:

j	=	Injury Type
CF	=	Criminal Fines
CD	=	Civil Damages
LC	=	Legal Costs
IC	=	Investigation Costs
AM	=	Additional Mitigations
SL	=	Societal Loss
PL	=	Productivity Loss

3.2.3.1. CRIMINAL FINES

Criminal fines in the context of safety for a prudent operator will generally stem from an injury or fatal outcome. This is dealt with by the following legislations:

- Breach of duty of employer towards employees and non-employees
    - Health and Safety at Work Act 1974 (section 33(1)(a) for breaches of sections 2, 3 and 7)
- Breach of Health and Safety regulations
    - Health and Safety at Work Act 1974 (section 33(1)(c))
- Corporate manslaughter
    - Corporate Manslaughter and Corporate Homicide Act 2007 (section 1)

In order to impose a sentence post fining the court must determine the category of the offence using culpability and harm factors. This is set out in *The Sentencing Council, Health and Safety Offences, Corporate Manslaughter and Food Safety and Hygiene Offences Definitive Guideline, 2015*.

Culpability factors are derived by the court from elements present in the case presented which are taken into account to reach a fair assessment of culpability. For Health and Safety breaches Culpability is split into four categories or two categories for Corporate Manslaughter.

3.2.3.1.1. HEALTH AND SAFETY BREACHES CULPABILITY

- Very High
    - Deliberate breach or flagrant disregard for the law
- High
    - Offender fell far short of the appropriate standard
    - Serious and/or systemic failure to address risk to health and safety
- Medium
    - Offender fell short of the appropriate standard
    - Systems were in place but not sufficiently adhered to or implemented
- Low
    - Offender did not fall far short of the appropriate standard
    - Failings were minor and occurred as an isolated incident

3.2.3.1.2. CORPORATE MANSLAUGHTER CULPABILITY:

Culpability is determined by four considerations and then deemed to be high or low:

- How foreseeable was the injury
- How far short of the appropriate standard did the offender fall
- How common is this kind of breach in the organisation
- Was there more than one death, or a high risk of further deaths, or serious personal injury in addition to death?

Harm is assessed by the court as a combination of seriousness and likelihood. This is only applied to Health and safety breaches as under the Corporate Manslaughter act, harm is implied.

		Seriousness		
Likelihood		Level A • Death • Lifetime physical or mental impairment • Significantly reduced life expectancy	Level B • Physical or mental impairment with long term effect • Progressive, permanent or irreversible condition	Level C • All other cases
	High	Harm 1	Harm 2	Harm 3
	Medium	Harm 2	Harm 3	Harm 4
	Low	Harm 3	Harm 4	Harm 4

Table 10

It is assumed that as a prudent operator and/or owner any incident that occurred would fall into a low culpability category. This is the justification for the inclusion of additional mitigation costs so as that post incident the level of culpability does not increase.

Similarly to the above statement it is assumed that in assessment of harm, the likelihood would fall into the low category. This limits the harm category to Harm 3.

When a fine is applied by the court this is determined on the basis of the company revenue with the aim of fines being proportionate. As this is the case Licensee Specific Appendices will be provided per company due to differences in revenue. These appendices will be revised upon re-issue of the Sentencing Council Guidelines, material changes to legislation and precedent or significant changes to company revenue.

Tables for criminal fines relating to safety will be given in the Licensee Specific Appendices.

3.2.3.2. CIVIL DAMAGES

As with the criminal law set out in the previous section a contravention of the Health and Safety at Work Act 1974 or the Management Regulations can be evidence of breach of common law duty of care.

Liability can be incurred through:

- Negligence
- Breach of statutory duty
- Strict liability
- Breach of contract

In the context of harm occurring for an asset failure the company would almost always be liable for at least the breach of statutory duty under the Health and Safety at Work Act 1974. Also in this context the injured party would be injured by the company's asset which would constitute a strict liability.

In order to include common law liabilities in the model the published guidance to the court will be used to set out the liability for injuries in each criticality category and referenced to: *The Judicial College Guidelines for the Assessment of General Damages in Personal Injury Cases, 13th Edition, 2015.*

In the guidelines where ranges are provided, the mean figure from the entire range will be applied. This is consistent with proportionality in criminal cases. In the 13th edition of the guidelines a 10% uplift is applied as per the upheld court appeal in *Simmons v Castle [2012] EWCA Civ 1288*. Following the precedence set by this case the uplift will be included in all future awards and as such will be applied in the model.

Specific tables linking criticality assessments to common law liabilities will be included in the Licensee Specific Appendices. These tables will be reviewed upon re-issue of the Judicial College Guidelines, material changes to legislation and precedent or significant variance in awards to those included in the tables.

3.2.3.3. INVESTIGATION AND LEGAL COSTS

All incidents that occur must be investigated ranging from a near miss to the most serious incidents. Due to the nature and complexity of investigations, a range will be provided in the Licensee Specific Appendices. Costs that contribute to investigations are:

- Internal staff time for investigation
- External contractors cost
- Forensic gathering costs

Legal costs are to be included to give a more accurate representation of risk management costs. As with cost of investigations these cost will vary on the case. A table will be provided in the Licensee Specific Appendices, making an approximation based on case studies for legal cost relating to the highest impact implied by criticality.

3.2.3.4. ADDITIONAL MITIGATIONS

When incidents are investigated and reviewed it is likely that number of additional mitigations will be identified to ensure that the outcome remains an isolated incident. Additional mitigations can range from improved systems or training to acceleration of asset replacement programmes. The application of additional measures is part of managing risk and will always be applied by a prudent operator and/or owner. This is compliant with maintain safety performance and managing network risk.

Approximated costs of additional mitigations will be included in the Licensee Specific Appendices. The costs are related to asset population sizes, numbers of staff and exposure to the public. Costs contributing to additional mitigations are:

- Process changes
- Updating policy documents
- Physical control measures put in place such as a Ballistic screen
- Training

3.2.3.5. SOCIETAL LOSS

Loss in quality of life, the direct impact to society contributions from personnel. The Health and Safety Executive provides guidance on appraisal values for societal loss.

3.2.3.6. PRODUCTIVITY LOSSES

Economic loss to organisation, from a loss in productivity due to a reduction in resource availability. The Health and Safety Executive provides guidance on appraisal values for productivity losses.

3.2.4. 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 an 'Exposure' modifier is incorporated into the 'Safety Cost' calculation.

An 'Exposure' modifier will be assigned to each asset based on an evaluation of the surrounding land use and levels of activity near to the asset/site under consideration. The TOs have yet to finalise the details on how to derive the 'Exposure' modifier. **Error! Reference source not found.** provides an indication of the factors that the TOs anticipate will be incorporated into this calculation.

Factors for Consideration	Scope	Supporting Information/Data/Evidence
Land Use and Personnel/Public Activity Levels	Reflects both the number of people who are potentially exposed to different types of injury caused by different failure effects and the likelihood that they will be present when the failure effect occurs.	ESQCR ratings, site information
Mitigation	Considers existing mitigation that has been put in place to reduce the likelihood of personnel/public being exposed to different types of injury caused by different failure effects (e.g. indoor/outdoor, signage, blast walls etc.)	Site information

Table 11

3.3. ENVIRONMENTAL CONSEQUENCE

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

$$Environmental\ Risk = Probability\ of\ Failure\ Mode\ Effect\ \times Environmental\ Cost$$

Equation 38

Where:

- **Probability of Failure Mode Effect** – represents the likelihood of different effects occurring as a result of assets failing
- **Environmental Cost** – represents the environment related costs associated with asset failure

For an individual asset the general expression for 'Environmental Cost' is:

$$Environmental\ Cost = Probability\ of\ Environmental\ Impact\ \times Cost\ of\ Environment\ Impact\ \times\ Exposure$$

Equation 39

The terms in the expression hold the following meanings:

- **Probability of Environmental Impact** – the likelihood that the environment is impacted when exposed to the effects of an asset failure
- **Cost of Environmental Impact** – the cost associated with environmental impact
- **Exposure** – modifier to reflect the sensitivity of the affected site

In reality the severity of the environmental impact and the likelihood of these impacts 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 the range of environmental impacts that can occur will vary. Taking into account these variables the 'Environmental Cost' can be more formally expressed as shown below:

$$Environmental\ Cost_i = \sum_j Probability\ of\ Environmental\ Impact_{j,i} \times Cost\ of\ Environmental\ Impact_j \times Exposure_j$$

Equation 40

Where:

i	=	Failure Mode Effect
j	=	Impact Type

The total 'Environmental Risk' associated with the asset can therefore be expressed as shown in the below equation.

$$Environmental\ Risk = \sum_i PoE_i \times Environmental\ Cost_i$$

Equation 41

Where:

PoE	=	Probability of Failure Mode Effect

3.3.1. FAILURE MODE EFFECT & PROBABILITY OF FAILURE MODE EFFECT

The failure mode effect represents the possible effects that TOs consider as a result of failure and the probability of failure mode effect represents its likelihood of occurrence. The effects that are considered by the TOs and the calculation of their likelihoods is described in the Process Appendices.

3.3.2. IMPACT TYPE & PROBABILITY OF IMPACT

Varying degrees of environmental damage can occur as a result of asset failure. The TOs anticipate categorising the severity of environmental impacts as follows:

Impact Type	Environmental Impact
1 Very low	Negligible environmental impact
2 Low	Minor environmental impact e.g. Localised spillage
3 Moderate	Major incident e.g. contamination of water courses / Environmental Agency (EA)/ Scottish Environmental Protection Agency (SEPA) Letter of Concern
4 Significant	EA/SEPA Enforcement Notice / Improvement Notice issued
5 Serious	EA/SEPA Prohibition Notice

Table 12

The 'Probability of Impact' represents the likelihood that an environmental impact occurs when an asset fails. Probabilities will be assigned to each 'Impact 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 an environmental perspective, and the probability of environmental impact would be zero. In addition, because it is assumed that the probability of impact applies to an individual site, the sum of probabilities across all impact type categories for a particular failure effect is less than or equal to unity (i.e. the environmental impact that occurs at a site can only be classified under a single severity category).

3.3.3. COST OF IMPACT

Costs will be assigned to the different environmental impact types. The costs will take into consideration, but are not limited to, the following factors:

- Criminal fines
- Civil damages
- Legal costs
- Investigation costs
- Application of additional mitigation

3.3.3.1. CRIMINAL FINES

Criminal fines in the context of damage to the environment will usually stem from contamination of land, air or water. This is dealt with by the following legislation:

- Illegal Discharges to air, land and water
    - Environmental Protection Act 1990 (section 33)
    - Environmental Permitting (England and Wales) Regulations 2010 (regulations 12 and 38(1), (2) and (3))
- Breach of Duty of care
    - Environmental Protection Act 1990 (section 34)
- Restrictions on use of public sewers
    - Water Industry Act 1991 (section 111)

Or through the equivalent legislation in Scotland which includes:

- The Water Environment (Controlled Activities)(Scotland) Regulations 2011
- Sewerage (Scotland) Act 1968

In order to impose a sentence post fining the court must determine the category of the offence using culpability and harm factors. This is set out in *The Sentencing Council, Environmental Offences, 2015*. In Scotland, The Sentencing Council Scotland is currently drafting the Environmental and wildlife Offences guidelines, which are due to be published in 2018/19.

Culpability factors are derived by the court from elements present in the case presented which are taken into account to reach a fair assessment of culpability. For environmental offences this is split into four categories: [*Sentencing Guidelines 2015*]

- Deliberate
    - Intentional breach or flagrant disregard, with the breach directly attributable to the organisation
    - Or, deliberate failure to put in place and enforce such systems as could be reasonably expected
- Reckless
    - Actual foresight of, or wilful blindness to the risk of offending but risk was taken no the less by someone whose position of authority in the organisation makes it directly attributable
    - Or, deliberate failure to put in place and enforce such systems as could be reasonably expected
- Negligent
    - Failure to take reasonable care and put in place and enforce proper systems to avoid commission of the offence

- Low Culpability
    - Offence committed with little or no fault on the part of the organisation
    - Presence and due enforcement of all reasonably required preventive measures
    - Proper preventive measures were unforeseeably overcome by exceptional events

Harm is assessed by the court into one of four categories: [*Sentencing Guidelines 2015*]

- Category 1
    - Polluting material of a dangerous nature
    - Major adverse effect or damage to air or water quality, amenity value, or property
    - Polluting material was noxious, widespread or pervasive with long-lasting effects on human health or quality of life, animal health or flora
    - Major costs incurred through clean-up, site restoration or animal rehabilitation
    - Major interference with, prevention or undermining of other lawful activities or regulatory regime due to offence
- Category 2
    - Significant adverse effect or damage to air or water quality, amenity value, or property
    - Significant adverse effect on human health or quality of life, animal health or flora
    - Significant costs incurred through clean-up, site restoration or animal rehabilitation
    - Significant interference with or undermining of other lawful activities or regulatory regime due to offence
    - Risk of category 1 harm
- Category 3
    - Minor, localised adverse effect or damage to air or water quality, amenity value, or property
    - Minor adverse effect on human health or quality of life, animal health or flora
    - Low costs incurred through clean-up, site restoration or animal rehabilitation
    - Limited interference with or undermining of other lawful activities or regulatory regime due to offence
    - Risk of category 2 harm
- Category 4
    - Risk of category 3 harm

It is assumed that as a prudent operator and/or owner any incident that occurred would fall into the low culpability category. This is the justification for the inclusion of additional mitigation costs so that post-incident the level of culpability does not increase.

Similarly to the above statement it is assumed that in assessment of harm a prudent operator is unlikely to exceed category 2 harm in the extreme. The primary route to category 2 harm is anticipated to be significant clean-up cost incurred for certain types of incident.

When a fine is applied by the court this is determined on the basis of the company revenue with the aim of fines being proportionate. As this is the case Licensee Specific Appendices will be provided per company due to differences in revenue. These appendices will be revised upon re-issue of the Sentencing Council Guidelines, material changes to legislation and precedent or significant changes to company revenue.

Tables for fines relating to environmental offences will be given in the Licensee Specific Appendices.

3.3.3.2. CIVIL DAMAGES

In the UK environmental legislation is based on the polluter pays principle. For simplicity of this model provision will be made for remediation cost as part of the cost of recovery appendices. The main routes for incurring cost would be through damages to property and amenity and nuisance. This is covered by:

- Environmental Damage (Prevention and Remediation) Regulations 2009
- Or in Scotland, Environmental Liability (Scotland) Regulations 2009

The regulations reinforce the polluter pays principle making organisations financially liable for damage to land, water and biodiversity. It is anticipated that a prudent operator would take all reasonable steps to remedy damage caused.

3.3.3.3. INVESTIGATION AND LEGAL COSTS

All incidents that occur must be investigated ranging from a near miss to the most serious incidents. Due to the nature and complexity of investigations, a range will be provided in the Licensee Specific Appendices. Costs that contribute to investigations are:

- Internal staff time for investigation
- External contractors cost
- Forensic gathering costs

Legal costs are to be included to give a more accurate representation of risk management costs. As with cost of investigations these cost will vary on the case. A table will be provided in the Licensee Specific Appendices, making an approximation based on case studies for legal cost relating to the highest impact implied by criticality.

3.3.3.4. APPLICATION OF ADDITIONAL MITIGATION

When incidents are investigated and reviewed it is likely that number of additional mitigations will be identified to ensure that the outcome remains an isolated incident. Additional mitigations can range from improved systems or training to acceleration of asset replacement programmes. The application of additional measures is part of managing risk and will always be applied by a prudent operator and/or owner. This is compliant with maintain safety performance and managing network risk.

Approximated costs of additional mitigations are included in the Licensee Specific Appendices. The costs are related to asset population sizes and environmental exposure. Costs contributing to additional mitigations are:

- Process changes
- Updating policy documents
- Training
- Environmental clean-up costs

3.3.4. EXPOSURE

Due to the distributed nature of networks it is important that exposure is taken into account. Environmental consequences are specific to individual assets and also their physical location. Some assets pose a greater risk to the environment than others. In order to account for this an 'Exposure' modifier is incorporated into the 'Environmental Cost' calculation. The TOs have yet to finalise the details on how to derive the 'Exposure' modifier. Table 13 provides an indication of the factors that the TOs anticipate will be incorporated into this calculation.

Factors for Consideration	**Scope**	**Supporting Information/Data/Evidence**
Proximity to Environmentally Sensitive Sites	Considers the proximity of assets to environmentally sensitive sites.	ESQCR Information Site Information
Mitigation	Considers existing mitigation that has been put in place to reduce the likelihood/consequence of different environmental events occurring as a result of different failure effects.	Site information

Table 13

3.4. FINANCIAL CONSEQUENCE

The Financial Consequence is derived from two elements:

1. Historic failure events that have occurred on the TOs' Transmission systems. These failure events are reported to Ofgem as part of the RRP and represent events that will lead to the need for a specific intervention

2. Cost for replacement of the asset

On the basis that catastrophic failure of the asset leads to replacement, the Financial Consequence values are derived according to Equation 42. The cost of recovery will only be considered for events where the asset can be recovered.

$$Financial\ Consequence\ in\ \pounds = Max\ (cost\ of\ recovery\ following\ catastrophic\ failure, cost\ to\ replace\ asset)$$

Equation 42

The Financial Consequence values are specific to each TO and will be detailed in the Licensee Specific Appendices. Note that environmental costs of recovery shall be included in the environmental consequence, not financial consequence. The cost for replacement of an asset remains confidential to each TO.

3.5. NETWORK RISK

As shown previously in Figure 1 and Equation 3, the Asset Risk is a function of the probability of each failure mode occurring and the impact of each of the consequences.

The Network Risk for each TO can be calculated by summing the Asset Risk associated with each lead asset as shown in Equation 43.

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

Equation 43

3.6 FURTHER WORK

It is noted from Ofgem's feedback that further work and improvements is required in this area of the methodology to fully comply with the requirements of the direction. The following list provides an indication of the principal work which is subject to further development:

- Determine and clarify how to derive and/or assign values to parameters in the 'Safety Risk' and 'Environmental Risk' calculations, including:
  - 'Probability of Injury' and 'Probability of Environmental Impact'
  - 'Cost of Injury' and 'Cost of Environmental Impact'
  - 'Safety' and 'Environmental' exposure modifiers
- Provide derived and/or assigned parameter values and source/reference data in the appropriate methodology document, public or company specific appendices,
- Ensure derived and/or assigned parameters are valid (realistic and credible),
- Confirm choice of 'Safety' and 'Environmental' Impact Type categories,
- Ensure, where possible, consistency with the DNO and GDN methodologies,
- Provide a list and explanation of underlying assumptions relating to the derivation of 'Safety Risk' and 'Environmental Risk'.

4. NETWORK REPLACEMENT OUTPUTS

4.1. INTERVENTIONS

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 TOs' networks. Without effective management of these activities, and understanding the related interactions between them, the TOs 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 expectation. In determining this efficient level, the TOs evaluate the cost of interventions against the benefits these interventions deliver.

In determining an intervention plan in any period, the TOs need to assess the Asset Risks and decide exactly which interventions to undertake. This requires the TOs 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 14 illustrates different types of intervention that would address failure modes in Figure 11 (not to scale).

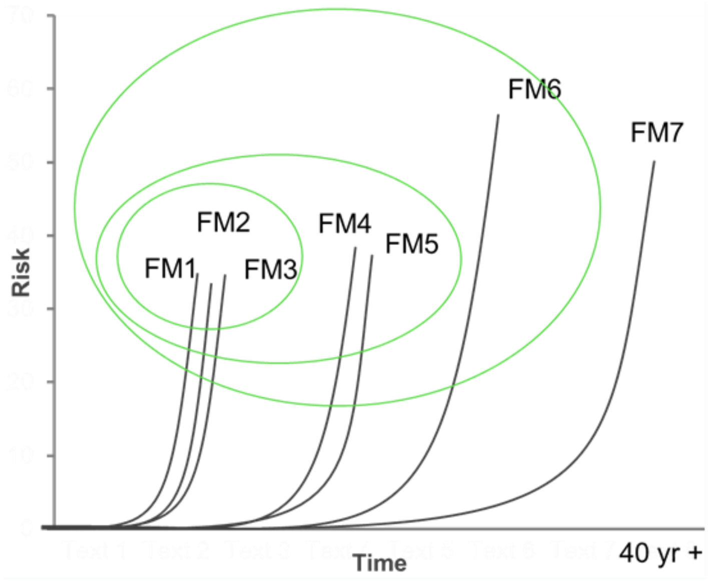


Figure 11

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

Table 14

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 the TO 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.

4.1.1. 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, as well as allowing the TOs to gather condition information so that performance risks are better understood and mitigated.

Maintenance is a fundamental tool in the TOs' 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. The TOs reassess maintenance policy and interval decisions 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 enable innovation.

When developing maintenance content and undertaking frequency reviews, the TOs have 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 maintenance tasks, identifying potential changes in performance and consideration of the impact that a change to the maintenance task frequency 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.

Through maintenance activities the TOs 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 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.

The intervals for the maintenance activities are determined through maintenance policy for each asset type, according to the specific requirements for that asset and manufacturer recommendations are also taken into account.

4.1.2. REPAIR

Repair is generally a reactive activity responding to a failure mode when it has occurred or, in some cases, to prevent a particular failure mode if it can be detected before failure 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.

4.1.3. REFURBISHMENT

The decision to refurbish instead of replace 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.

4.1.4. 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.

4.2. ASSETS REQUIRING SEPARATE TREATMENT

4.2.1. HIGH IMPACT, LOW PROBABILITY EVENTS

A significant amount of work has been undertaken by the TOs with respect to High Impact, Low Probability events. This work will be directly fed into the cross sector (Electricity and Gas, Transmission and Distribution) working group that has been initiated by Ofgem.

4.3. UNCERTAINTY

Statistical uncertainty accounts for random fluctuations in measurement, or to account for an error in the methods used to make measurements. Random fluctuations follow a normal distribution, and the standard deviation can be used to describe the uncertainty within the distribution i.e. the range either side of the mean. Note that statistical uncertainty cannot account for systemic error, which can occur when making assumptions, or using a reference point which is not correctly calibrated.

The mean ($\bar{x}$) is calculated using:

$$\bar{x} = \frac{1}{N}\sum_{i=1}^{N} x_i$$

Equation 44

The standard deviation (σ_x) is calculated using:

$$\sigma_x = \sqrt{\frac{1}{N-1}\sum_{i=1}^{N}(x_i - \bar{x})^2}$$

Equation 45

Statistical uncertainty can be considered at varying levels of abstraction, so to be consistent with the development of the other aspects of the NOMs methodology, it is proposed to consider statistical uncertainty at a lead asset level.

Each lead asset will have its own standard deviation, demonstrating where the inputs (including time, duty and condition information) for the FMEA and FMECA calculations differ from the mean.

The process that occurs within the FMEA and FMECA determine how the total standard deviation is calculated for each lead asset. This can be calculated using Table 15, which demonstrates how to calculate the total standard deviation when the process involves addition, multiplication and indexes:

Equation for normal distribution	Standard deviation
$d = a + b - c$	$\sigma_d = \sqrt{\sigma_a^2 + \sigma_b^2 + \sigma_c^2}$
$d = \frac{ab}{c}$	$\frac{\sigma_d}{d} = \sqrt{(\frac{\sigma_a}{a})^2 + (\frac{\sigma_b}{b})^2 + (\frac{\sigma_c}{c})^2}$
$d = \frac{a^l b^m}{c^n}$	$\frac{\sigma_d}{d} = \sqrt{(l\frac{\sigma_a}{a})^2 + (m\frac{\sigma_b}{b})^2 + (n\frac{\sigma_c}{c})^2}$

Table 15

The standard error is used when relating a sample size to a population to indicate the relationship between the true mean of the population, and the mean of the sample population.

$$SE = \frac{\sigma}{\sqrt{N}}$$

Equation 46

Standard errors provide simple measures of uncertainty in a value and are often used because:

1. If the standard error of several individual quantities is known then the standard error of some function of the quantities can be easily calculated in many cases

2. Where the probability distribution of the value is known, it can be used to calculate a good approximation to an exact confidence interval

3. As the sample size tends to infinity the central limit theorem guarantees that the sampling distribution of the mean is asymptotically normal

The standard error shall be used to determine the total uncertainty in the network risk calculation for each lead asset. The sum of these standard errors relates to the total uncertainty in the network risk calculation. Figure 12 demonstrates where the uncertainty shall be included within the network risk calculation.

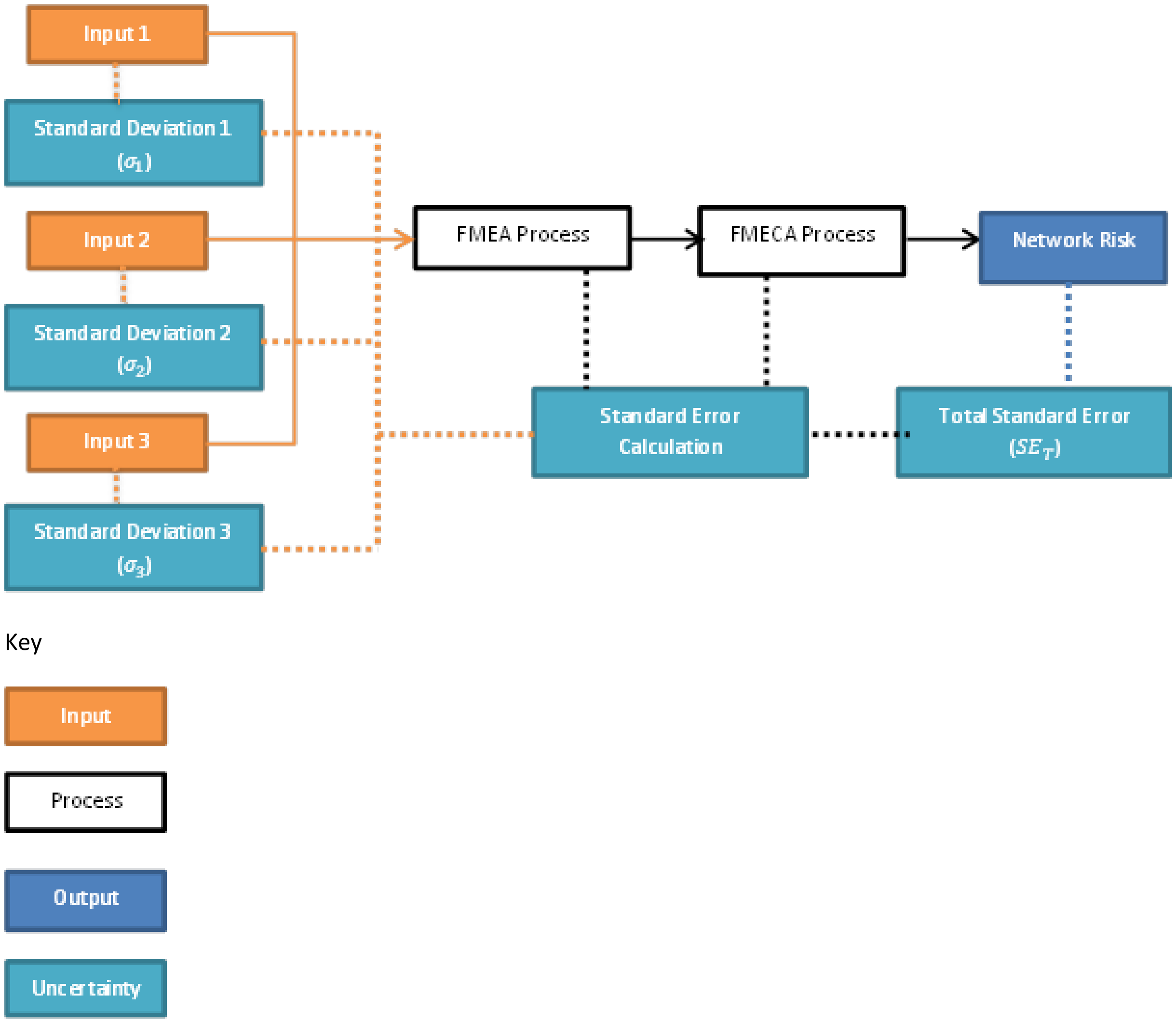


Figure 12

The above approach has been carried out on a reasonable endeavours basis to address quantification of uncertainty at this stage, however further work is required in this area to account for uncertainty in parameter estimates which will be included in the relevant Process Appendices. This will be included in the next phase of development.

5. RISK TRADING MODEL

The Risk Trading Model will calculate the monetised risk for each asset and aggregate to give the total Network Risk. It will reflect the processes and calculations described within this methodology and associated appendices.

The Risk Trading Model (RTM) has been developed with the aim that it will be used to assist in planning and prioritising work to be undertaken on high risk assets within the transmission network between a start year (Y_o) and an end year (Y_n) (e.g. 2021 and 2029 for the RIIO-T2 period).

The RTM is based upon a catalogue of the assets in each TOs transmission network. Included within this catalogue are specific details of the assets, along with the associated Probability of Failure in the start year (PoF_{Y0}), the monetised Consequence of Failure (CoF) and a forecast Probability of Failure in the end year (PoF_{Yn}). The RTM investigates the impact that different investment plans have upon the monetised risk of the individual asset, asset category and the whole network at Y_n. Figure 13 outlines the data used and steps applied within the RTM.

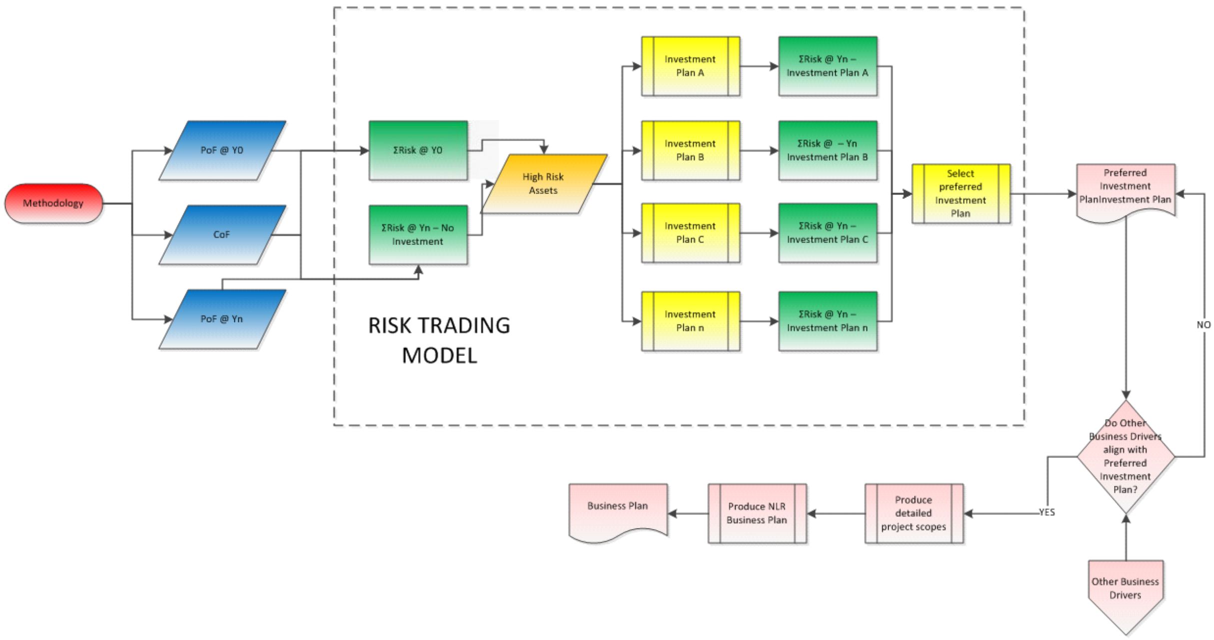


Figure 13

The development of the Risk Trading Model has been carried out on a reasonable endeavours basis. Its development is contingent upon a number of topics which will form part of the next phase of work, including amendments to the Consequence calculation, evaluation of input parameters and the Calibration, Testing & Validation exercise. The development of the Risk Trading Model will ensure a consistent format for outputs and will be included within the detailed Implementation Plan. Further detail on the Risk Trading Model for NGET and SPT/SHE-T can be found in the Process Appendices.

6. CALIBRATION, TESTING AND VALIDATION

The methodology has been designed to enable the parameters to be easily adjusted to reflect the results of the testing, validation and calibration exercises. The calibration, validation and testing will include scenarios and tests where defined criteria are set out prior to the test and the results are compared against these criteria.

CALIBRATION

Ensure consistency in the application of the methodology. All three TOs will work together to ensure that the application of this methodology is consistent.

CALIBRATION OF CONDITION

All three TOs will compare their asset condition information. It is expected that for assets in the same condition with the same history, operating regime, operating environment and duty, each asset would expect to have a similar and comparable probability of failure for all TOs.

CALIBRATION OF CONSEQUENCE

Consequence of failure will be compared across the TOs. Where it is possible to compare consequences, these would be expected to have the same scores for the same criteria. It is expected that safety and environmental consequence scoring would demonstrate a greater degree of consistency between the TOs.

However, due to the differing scales of the TOs respective networks, there may be some instances where specific criticality score may need to be used, most notably with system consequence. The TOs can compare the ratio of consequence scores that fall into the very high, high, medium and low categories to ensure a consistency of approach.

TESTING

In order to test the monetised network risk, the spreadsheet models for each asset group will be populated with data.

Asset risk will be calculated for current condition and forecast condition for each asset group.

An independent expert will be appointed to check the spreadsheet and provide assurance that its internal calculations are correct, verifying that the models perform according to this methodology.

VALIDATION

Validation that the PoF and consequence values calculated by the methodology are consistent with actual outcomes

The probabilities of failure will be validated periodically by ensuring the summated values are consistent with actual asset performance. The consequence monetary values will be validated periodically by adding new events as they occur and comparing them against the value being used.

Confirmation that the number of assets planned for intervention is consistent with the need for intervention

Validation of this methodology will involve confirmation that the numbers of assets that are expected to be replaced or refurbished over the RIIO-T1 period is consistent with the TOs' investment plans. This involves monitoring the network risk with intervention and network risk without intervention. The difference between these network risk positions will confirm whether the TOs' investment plans reflect the number of assets that are planned for replacement or refurbishment is consistent with the need for intervention.

FURTHER WORK

The development of this section has been carried out on a reasonable endeavours basis as the Calibration, Testing and Validation process requires a degree of certainty in the methodology to identify and plan the activities required. The separate implementations of the Common Methodology highlights the importance of a robust Calibration, Testing and Validation process to provide comparable outputs. It is acknowledged at this stage that there is further development work required to produce a detailed plan and model:

1. Review the tabulated approach from the main methodology with testing validation and calibration cases against each element in the table addressing inputs, outputs and identifying any gaps in the CTV plan
2. The TOs finalise the resources and time scales for the delivery of the CTV
3. A full testing of assumptions required for testing the parameters and formula of the health score
4. Consideration of the optimisation methodology, machine learning methodology and the use of random decision forest approaches
5. Develop a sensitivity case to test, including an approach to address missing or unavailable data
6. Perform an overall sensitivity test
7. Develop parallel test case separately for SHET/SPTL (with a draft to Ofgem)

A separate appendix for Calibration, Validation and Testing (including spreadsheet) accompanies this issue of the NOMs methodology which gives indications of the elements which will be included for Calibration, Validation and Testing. This document and spreadsheet remains to be fully populated during the ongoing development required in this area.

APPENDIX I - IMPLEMENTATION OF THE INCENTIVE MECHANISM FOR RIIO-T1

For the RIIO-T1 submission, the Network Replacement Outputs targets encoded into Special Licence Condition 2M were set based on the forecast of expected Replacement Priorities at 31 March 2021. To generate this forecast of expected Replacement Priorities the TOs used forecast asset deterioration and the forecast investment plans for the RIIO-T1 period.

As part of the RIIO-T1 price control review, Ofgem assessed the TOs forecast asset deterioration and forecast investment plans and subsequently adopted the forecast asset replacement priorities at 31 March 2021 as the basis of the Network Replacement Outputs.

To align with the intent of maintaining reliability at historic levels, the forecast investment plans were developed to keep the network risk at a level similar at the end of RIIO-T1, as it was at the beginning of RIIO-T1 in line with stakeholder expectations.

The following quotations relate to reliability NGET stakeholder engagement sessions held for Energy Not Supplied:

"In terms of the current level of reliability from National Grid, attendees were in general very happy, and expressed a desire for it to be maintained at its current level for the next 20-30 years. However, they did acknowledge that this would come at a cost".

Stage one workshop Brunswick report, 10th December 2010

"Reliability is not something on which most participants are willing to compromise – it's widely expected to remain at current levels (or higher)."

Stage one workshop Brunswick report, 19th January 2011

There are two principle sources of uncertainty around the forecast of network risk:

1. Forecasting of asset deterioration

2. Unexpected type faults

Asset deterioration is inherently uncertain and probabilistic modelling techniques are used to forecast condition. The forecast Replacement Priorities at 31 March 2021 were based on the median value and thus expected forecast of network risk.

Unexpected type faults cannot be forecast but can have a significant impact on network risk, causing significant cost and disruption of the investment plan. It would not be sensible to model this risk probabilistically so these were not included in the forecast replacement priorities.

1.1. USING THE NETWORK OUTPUT MEASURES

The TOs' NOMs are used internally to enhance current asset management processes and understanding of business drivers. This is especially in relation to the development, maintenance and operation of our networks and in assessing future network expenditure.

In addition to the joint methodology statement, the TOs have developed specific appendices which describe how they use the NOMs within our respective businesses. These specific appendices are confidential.

Under RIIO-T1, the TOs have each developed integrated business plans which are supported by a suite of mechanisms designed to help manage the uncertainty that the electricity industry faces over the next decade.

Non-load related activities are the capital and direct operating elements of the plan which are focused on maintaining performance of our assets through replacement, refurbishment and maintenance.

Through these activities, the TOs' intention is to improve our safety and environmental performance whilst maintaining reliability (in terms of Energy Not Supplied) at current levels. These activities are targeted at delivering stakeholders' requirements, from connecting new supplies to providing a safe, reliable service.

The TOs' business plans are designed to manage the ongoing safety, reliability and environmental performance of our networks. The potential customer impact associated with the deteriorating performance of assets towards the end of their useful life continues to drive a programme of interventions on our transmission network assets.

The TOs manage interventions on our equipment to ensure that:

a. The number, severity and criticality of equipment failures are acceptable to the TOs and our stakeholders

b. Long term replacement plans can be achieved without having an unacceptable impact on reliability, availability, quality of supply, health, safety and environmental performance, and transmission constraints

c. Long term capital forecasts are within acceptable levels for efficient deliverability, procurement and financing requirements

The available interventions for managing the performance of assets range from routine maintenance to full replacement. At the highest level, there are three options for intervention for each lead plant type which have definitions agreed with Ofgem:

a. Maintenance

b. Repair

c. Refurbishment

d. Replacement

1.1.1. DECISION MAKING

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

Figure 14 shows how the process by which elements of NOMs feed into an investment plan. Health criteria (e.g. condition, performance) categorised into AHIs represent the Network Asset Condition. These AHIs are combined with information about Criticality to determine Replacement Priorities. These Replacement Priorities are combined with other factors (e.g. outages, resources) to determine scheme priority which is used to determine the investment plan.

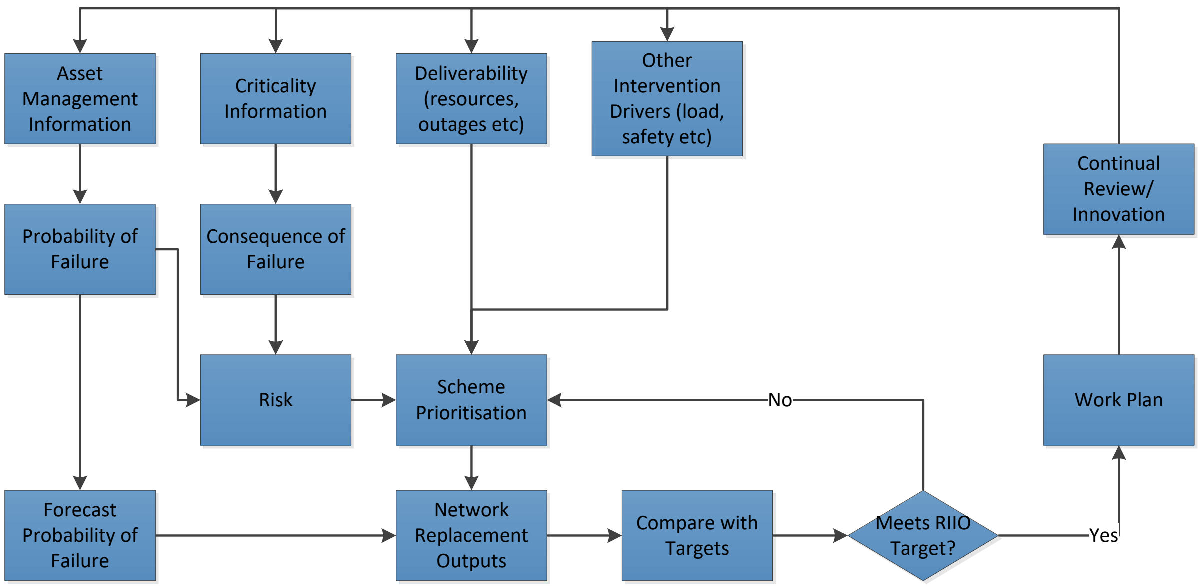


Figure 14

The Risk represents the level of Network Risk held on the system and has been developed in a way that ensures a consistent understanding of risk across all asset types. They take into account changes to asset populations, including load and non-load related replacement volumes.

The Risk determines the Network Replacement Outputs, providing Ofgem with the ability to monitor and assess the TOs' asset management performance. The non-load related targets for the Network Replacement Outputs are coded into the respective licences for each TO in Special Licence Condition 2M. The process for setting the targets is illustrated in Figure 14.

Network Performance is currently monitored through the Average Circuit Unreliability (ACU) metric, which represents network unavailability as a result of asset unreliability. This metric records the impact of Functional Failures and is used to understand the impact of unreliability on the TOs' networks.

Work has been undertaken to further understand the relationship between asset condition and network performance. The ACU is presented in a format that disaggregates the metric by equipment group and then by asset condition. Figure 15 shows the conceptual relationship between Energy Not Supplied events and other network performance metrics. The TOs are continuously developing their understanding of the relationship between Asset Health and Network Performance.

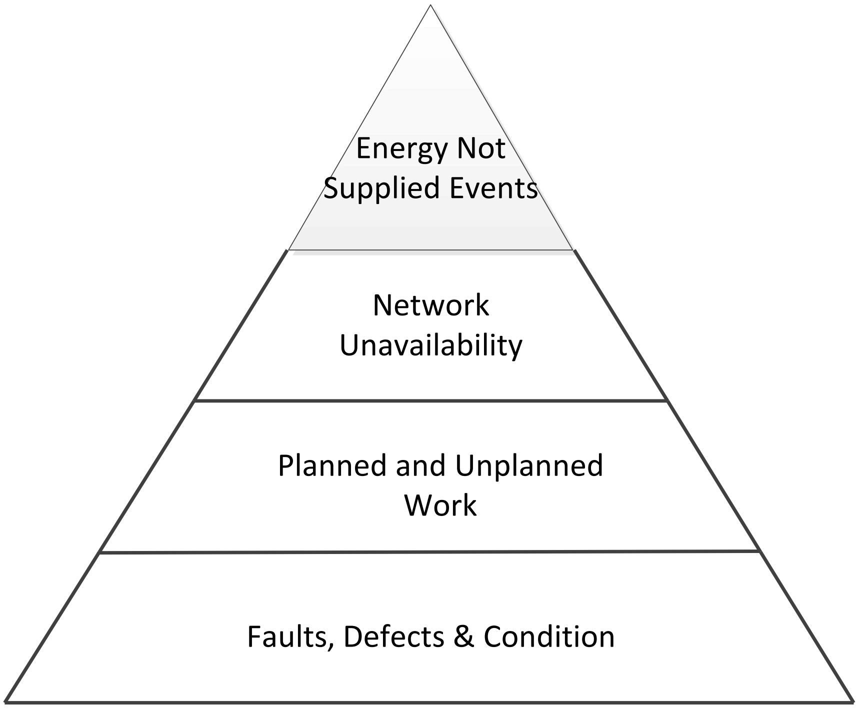


Figure 15

Network Capability is used to understand the localised demand driven need for developing Transmission infrastructure. Utilisation is represented as demand or generation as a percentage of capacity. The Capability measure records the impact of specific schemes on the capability for each boundary, using thermal, voltage and stability incremental capability across each boundary.

1.2. REPORTING TO THE AUTHORITY

1.2.1. LICENCE REQUIREMENTS

The NOMs will be reported to Ofgem as part of the annual Transmission Regulatory Reporting Packs (RRP) as required in Standard Licence Condition B15: Regulatory Instructions and Guidance (RIGs).

Licence Condition 2L.6 requires that the TOs provide information (whether historic, current or forward-looking) about the NOMs supported by such relevant other data and examples of network modelling, as may be specified for the purposes of this condition in any RIGs that have been issued by the Authority in accordance with the provisions of Standard Licence Condition B15.

Network Output Measure	Reported in RRP Table
Network Asset Condition	6.15.1_NOMs_detail
Network Risk	6.15.2_NOMs_RP
Network Performance	5.10_ACU
Network Capability	5.3_Boundary_Tran_Requirements 5.4_Bound_Capab_Dev 5.5_Demand_&_Supply_Sub
Network Replacement Outputs	6.15.2_NOMs_RP

Table 16

In addition to the submitted tables, the TOs provide a narrative which explains changes to the outputs from the previous year.

1.2.2. REPORTING TIMESCALES

The reporting year for the provision of information is from 1 April to 31 March the following calendar year. The information required under the RIGs will be provided not later than 31 July following the end of the relevant reporting year.

For the RIIO-T1 period, the first reporting period was 1 April 2013 to 31 March 2014.

1.2.3. DATA ASSURANCE

Licence Condition B23 requires each TO to undertake processes and activities for the purpose of reducing the risk, and subsequent impact and consequences, of any inaccurate or incomplete reporting, or any misreporting, of information to the Authority.

To ensure compliance with this licence condition, each TO carries out risk assessments to understand the implications of reporting inaccurate, inconsistent or incomplete data. Each NOM table reported in the RRP has undergone such a risk assessment. Where improvements can be made to data systems or processes, actions are planned that are proportionate to the risk of a submission in order to reduce the impact of inaccuracies in the submissions.

In providing data the TOs have developed work instructions for each table to be submitted to ensure a consistent approach.

Data concerning the asset inventory, condition scoring and criticality information is specific to each TO. Details about the type and quantity of data are described in each Licensee Specific Appendix.

Specifically, these describe the data that informs health indices (in line with the existing NOMs methodology) and how it is used for specific assets. They indicate the volume of available data and whether any data has to be inferred. They explain whether there is any blanket replacement of certain assets and associated reasons. These also describe how any limitations in the data affect the confidence in scoring for health and criticality and how any uncertainties can be quantified.

1.3. NETWORK PERFORMANCE

1.3.1. LICENCE REQUIREMENTS

Paragraph 2L.4(c) of Special Licence Condition requires the TOs to enable the Evaluation of:

"Those aspects of the technical performance of the TO's Transmission system which have a direct impact on the reliability and cost of services provided the TO as part of its Transmission business (Network Performance)"

The key elements from this Special Licence Condition are:

a. Performance of the TO's Transmission system

b. Direct impact on the reliability and cost of the services

1.3.2. METHODOLOGY

Network Performance is a key output for the customers of the TOs. To provide a full picture on Network Performance, it is necessary to consider a number of complementary performance measures. This is because some measures consider events only and some consider a combination of event and duration.

Reduced reliability of the Transmission network increases the risk of loss of supply for directly connected customers and increased costs to market participants which impact the consumer. An increased number of loss of supply events creates a cost of inconvenience to the general consumer and in extreme cases will result in a significant impact upon the economy.

Average Circuit Unreliability (ACU) is derived from the unavailability of the network due to outages occurring as a result of unreliability events which cannot be deferred until the next planned intervention and is defined in Equation 47 below.

$$\frac{Total\ Duration\ of\ Repair\ (cumulative\ across\ circuit)}{Number\ of\ Circuits\ \times Duration\ of\ reported\ time\ period}$$

Equation 47

Duration in the context of ACU is a continuous number and is not rounded or truncated at any stage of the calculation, thus no errors are introduced into the calculation.

The monthly duration is calculated using a differing number of days in a month and so any calculation to derive a yearly number will require a suitable weighting of monthly values to account for this.

The outages which are classified as being included within the definition of ACU are:

a. Enforced unreliability outages taken at less than 24 hours' notice (otherwise known as unplanned unavailability)
b. Planned unreliability outages taken after 24 hours' notice

All unreliability related outages are included within the definition of ACU. The definition above assumes that no outages are planned with less than 24 hours' notice as any such outage would fall into part a. in the definition above.

The TOs have investigated whether the Fault and Failure data provides a statistically significant dataset to derive correlations with asset condition. The actual number of Faults and Failures is very small across all the TOs. This is a result of:

a. Actual population sizes of the assets. The population is not large enough to experience a great number of reliability related Faults and Failures

b. Asset management approach within the business. The TOs maintain assets to manage the number of faults experienced an aim to replace before failure using AHI and Criticality to prioritise asset replacement candidates. This means many Faults and Failures that might occur are avoided.

The number of Faults and Failures has proven insufficient to enable accurate correlations with asset condition. Details of the investigations undertaken by each TO are included in the existing respective Licensee Specific Appendices.

By looking at Functional Failures, there is a greater set of data which can be used for correlation with asset condition. Functional Failures include those unreliability related outages which are used to determine ACU.

Each TO has varying historical datasets with which to produce correlation of asset unreliability with asset condition. In addition, given the introduction of AHIs on a consistent basis across the TOs, there is limited historical condition information to provide correlation with Functional Failures. These historical datasets will grow with time and thus the accuracy of the correlations will improve.

The investigations undertaken by each TO include the analysis undertaken to identify correlations between asset unreliability and asset condition are detailed in the Licensee Specific Appendices.

1.3.3. ENSURING CONSISTENCY

The ACU is calculated consistently using the same definitions in line with the RIGs for all TOs.

The calculation to determine Energy Not Supplied for incentivised loss of supply events according to transmission licence condition 3C is based upon a joint methodology statement. This was developed jointly between all transmission TOs and is therefore applied consistently.

1.3.4. REPORTING

The TOs report a comprehensive set of Network Performance measures in the form of Energy Not Supplied (Table 6.3), Average Circuit Unavailability (Table 5.10) as well as Faults and Failures information (Table 5.2) with associated commentary through the Transmission RRP.

For ACU, the total number of circuits used in this calculation varies by TO and will vary from year to year as the networks are modified. For this reason, the number of circuits used as part of the ACU calculation is reported as at 31 March each year.

1.3.5. CONTINUOUS IMPROVEMENT

The TOs will continue to assess the performance of their assets and, through monitoring these metrics, will use them to develop strategies to manage asset unreliability.

1.3.6. EXTERNAL PUBLICATION

There are no issues with the external publication of the NOMs methodology for Network Performance. The summary tables as reported in the Transmission RRP should not be published externally.

1.4. NETWORK CAPABILITY

1.4.1. LICENCE REQUIREMENTS

Paragraph 2L.4(d) of the Special Licence Condition requires the TOs to enable the evaluation of:

"The Network Capability measure, which relates to the level of the capability and utilisation of the TO's Transmission system at entry and exit points and to other network capability and utilisation factors"

The key elements from this Special Licence Condition are:

a. Information about Transmission system capability

b. Information about Transmission system utilisation

1.4.2. METHODOLOGY

The TOs report on Transmission system capability as part of the Transmission RRP which monitors the existing Transmission capacity being provided by the TOs on the NETS.

Likewise, the Transmission RRP requires the individual TOs to collect information relating to more localised demand driven needs for developing transmission infrastructure. This is presented in Table 5.5 with utilisation being represented as demand as a percentage of capacity. This shows the relationship between localised demand and capacity and hence provides a proxy measure for utilisation.

Adopting these measures ensures consistency in reporting and interpretation of requirements across all TOs.

1.4.3. PROVISION OF INFORMATION ON VOLTAGE AND STABILITY (THERMAL)

Information is reported in the ETYS at a boundary level. This boundary capability is calculated based on the most onerous limitation whether this is thermal or voltage.

Where stability constrains boundary capability this data will be provided where it is available.

Transmission RRP Table 5.4 reports present year boundary capability and incremental capability for the reinforcement completed in the present year.

1.4.4. ENSURING CONSISTENCY

Capability and utilisation is reported by the TOs in a consistent manner according to the RIGS. As described earlier, demand is represented as a percentage of capacity, hence ensuring a consistency of reporting despite the differing scales of the respective TOs' networks.

1.4.5. REPORTING

Tables 5.3 and 5.4 of the Transmission RRP reflect the capability requirement and boundary capability for all system boundaries. Table 5.5 reflects the utilisation requirement.

Table 5.3 collects information on Transmission capacity against required transfer levels at key parts of the Transmission system.

Actual capability information is provided in Table 5.4 and reflects the impact of specific schemes on the capability for each boundary. For each scheme the thermal, voltage and stability incremental capability across each boundary is given. In addition, the Table shows the capabilities at the start of the reporting period and the final overall capability (based on all schemes). The RIGs provide the rules for creating Table 5.4.

The rules for creating Table 5.5 are also taken form the RIGs. Information will be used from the most recent business planning studies. Further rules are as follows:

a. Peak Demand: the maximum demand of the demand group at the substation

b. Maintenance Period Demand: as defined in the NETS SQSS

c. n-1 Capacity: the first circuit outage condition as defined in the NETS SQSS

d. n-2 Capacity (300 MW demand groups only): the second circuit outage condition as set out in the NETS SQSS. This is only applicable for substations where the peak group demand is greater than 300 MW.

1.4.6. CONTINUOUS IMPROVEMENT

The TOs will continue to review the submitted information for Network Capability.

1.4.7. EXTERNAL PUBLICATION

There are no issues with the external publication of the proposed NOMs methodology for Network Capability. The summary tables which form part of the Transmission RRP should not be published externally. The Licensee Specific Appendices should not be published.

1.5. RIIO-T1 NETWORK REPLACEMENT OUTPUT TARGETS

1.5.1. TARGET SETTING PROCESS

Figure 16 shows the process for setting the RIIO-T1 network replacement output targets. This differs significantly to the methodology described herein. Details can be found in previous versions of this document.

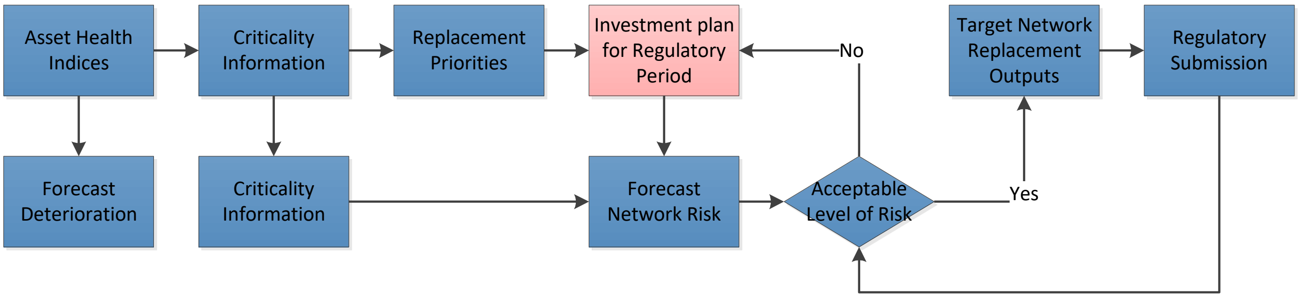


Figure 16

The TOs actively develop their asset management capabilities. The risk and criticality approach targets asset interventions on assets in poorest condition with the highest consequences of failures. One of the fundamental parts of this approach is the TOs' ability to forecast asset degradation, supported by extensive knowledge of the assets informed through innovation, failure investigations, forensic investigations, condition monitoring and assessment, family history, international experience and asset performance data.

For the RIIO-T1 submission, the network replacement output targets encoded into Condition 2M of the Transmission Licence were set based on the forecast of expected asset Replacement Priorities (Network Risk) at 31 March 2021. To generate this forecast of expected Replacement Priorities the TOs used forecast asset deterioration and their forecast investment plans for the RIIO-T1 period. As part of the RIIO-T1 price control review, Ofgem and their consultants assessed the TOs forecast asset deterioration and forecast investment plans and based on this assessment adopted the asset Replacement Priorities at 31 March 2021 as the basis of the network replacement output targets.

To align with the stated intent to maintain reliability at historic levels, the forecast investment plans were developed to keep the network risk at a similar level at the end of RIIO-T1, as it was at the beginning of RIIO-T1.

There are two principal sources of uncertainty around forecast network risk. These are:

i) Uncertainty associated with the forecasting of asset degradation;
ii) Uncertainty associated with unexpected type faults.

Asset degradation is inherently uncertain and probabilistic modelling techniques are used to forecast future condition. This is combined with information on asset Criticality to calculate a forecast of Replacement Priority.

The forecast Replacement Priorities at 31 March 2021 were based on a 50^{th} percentile, giving the median value and thus expected forecast of network risk.

To ensure the uncertainty in future asset condition was included in the assessment of forecast network risk by Ofgem and their consultants, confidence levels at 25% and 75% were additionally provided to Ofgem to provide an understanding of distribution of uncertainty around the expected Replacement Priorities.

Unexpected type faults cannot be forecast but can have a significant impact on network risk, cause significant costs and lead to disruption of the capital programme. It would not be sensible to model this risk probabilistically so these were not included in the forecast of Replacement Priorities.

Throughout the eight year RIIO-T1 period, the TOs are learning more about their assets as they age and experience new duty cycles. Further assets will enter the wear-out period of life which will allow collection of new condition information. In addition it is likely failures will occur which reveal new deterioration mechanisms which are currently unknown.

This new condition information and new deterioration mechanisms will feed into the deterioration modelling and asset technical lives. In addition, the TOs continue to seek new cost-beneficial intervention options to manage the evolving condition of the assets. In some cases this will allow some life extension and in other cases this will cause life reductions.

1.5.2. CONVERSION OF RIIO-T1 TARGETS

By taking the information known about lead assets at the time of RIIO-T1 submission, the existing Network Replacement Outputs targets for each TO can be converted into monetised Network Risk by forecasting the Asset Risk for each asset to 31 March 2021 and apply the RIIO-T1 submission business plan to give a Network Risk value as a target for the end of the period.

1.6. JUSTIFICATION

A significant amount of work has been undertaken by the TOs with respect to Justification. This work will be directly fed into the cross sector (Electricity and Gas, Transmission and Distribution) working group that has been initiated by Ofgem.

1.6.1. TREATMENT OF LOAD RELATED INVESTMENT

The target for the Network Replacement Outputs is the level of Network Risk based on investment in non-load related (NLR) schemes only. Any replacement of assets that fall into the window of replacement that is achieved from load related (LR) investment must be excluded from the overall level of Network Risk when determining whether the targets have been met and how the TOs have performed at the end of RIIO-T1.

As the impact of LR investment is excluded, the Network Risk reported against the target does not reflect actual Network Risk on the system. To this end, the TOs will report both NLR Network Risk and actual Network Risk for each reporting year. It is particularly important for the TOs to understand the actual level of Network Risk to appropriately manage assets and to plan investments going into the future. For each regulatory period it is very important that the investments and outputs are derived from actual Network Risk.

The TOs report the asset additions and disposals and the type of investment (whether LR or NLR) year on year in Table 5.6 of the Regulatory Reporting Pack. In order to convert the actual Network Risk value into one that is only based on NLR investment, the impact of all LR investment within the specific time period being reported needs to be removed. The NLR only Network Risk is obtained by assuming the LR investments had not occurred. NLR only Network Risk is calculated by adding the Asset Risk associated with the unit (e.g. Transformer) or length (e.g. Cable) that was removed on the LR scheme back into the inventory and subtracting the Asset Risk associated with the LR unit or length that was added. This creates a 'ghost asset'.

There may be instances where an asset replaced under a LR investment suffers an early life failure. Special treatment is required for such failures because NLR only Network Risk does not take LR investment into account. Therefore an early life failure of an asset commissioned under a LR investment cannot be simply represented because the asset that has failed has previously been excluded from the NLR only Network Risk. If an asset replaced under a LR investment ('ghost asset') fails, the effect of replacing the ghost asset should be same as the effect of a NLR replacement.

When the LR investment replaces an existing asset on the system:

1. If the LR investment asset is replaced after failure, the NLR only Network Risk will first be decreased by the volume associated with the asset that is replaced by the LR investment (with corresponding Asset Risk), and secondly increased by the volume associated with subsequent NLR volume on (with corresponding Asset Risk)

2. If the LR investment asset is decommissioned after failure (i.e. not replaced) the NLR only Network Risk will be decreased by the volume associated with the asset that is replaced by the LR investment (with corresponding Asset Risk)

When the LR investment introduces an additional asset on the system:

1. If the LR investment asset is replaced after failure, the NLR only Network Risk will be increased by the volume associated with the NLR volume on and corresponding Asset Risk

2. If the LR invest asset is decommissioned after failure (i.e. not replaced) the NLR only Network Risk will not be affected

There may be circumstances that TOs decide not to replace the failed asset and simply decommission it. In this case there will be no impact on NLR only Network Risk.

1.7. IMPLEMENTATION PLAN

There are a number of areas that require further development, as identified in relevant sections in this Common Methodology and the Process Appendices. Before the NOMs methodology can be implemented, there are a number of activities that are required to be completed as shown at a high level in Figure 17.

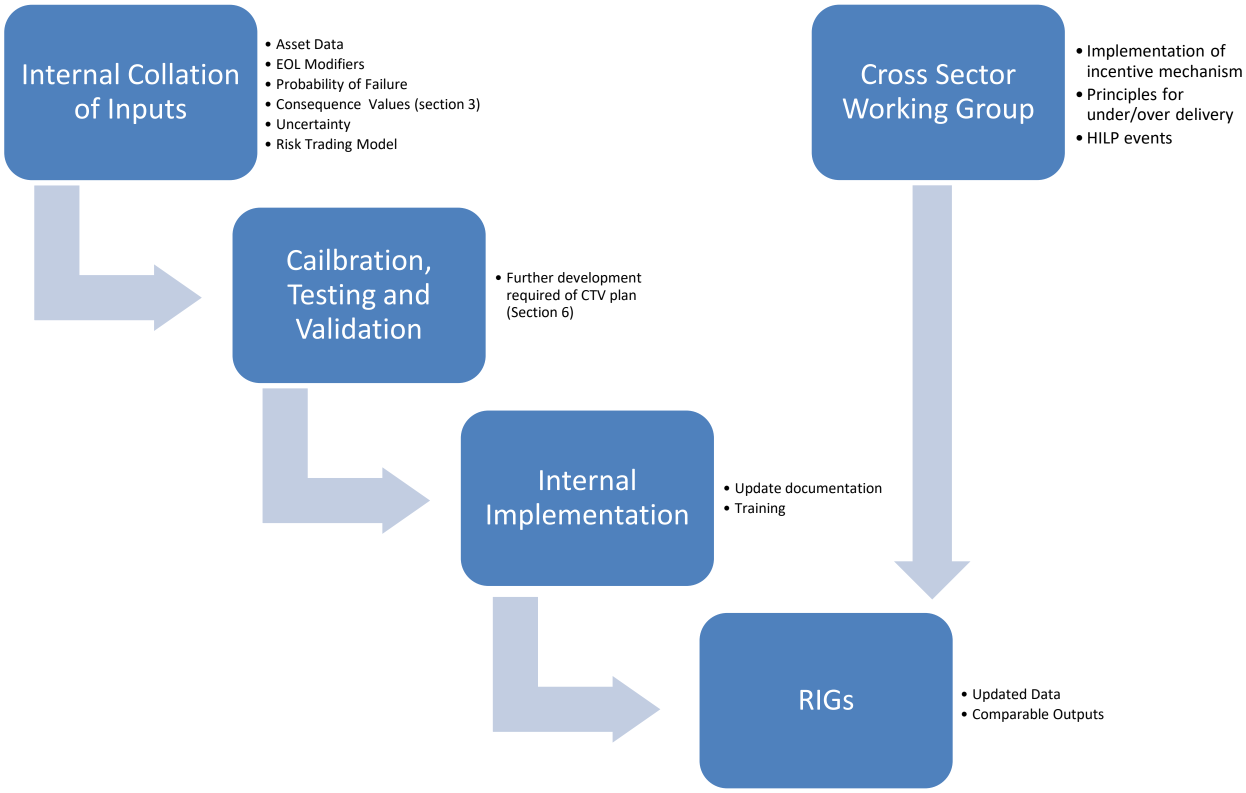


Figure 17