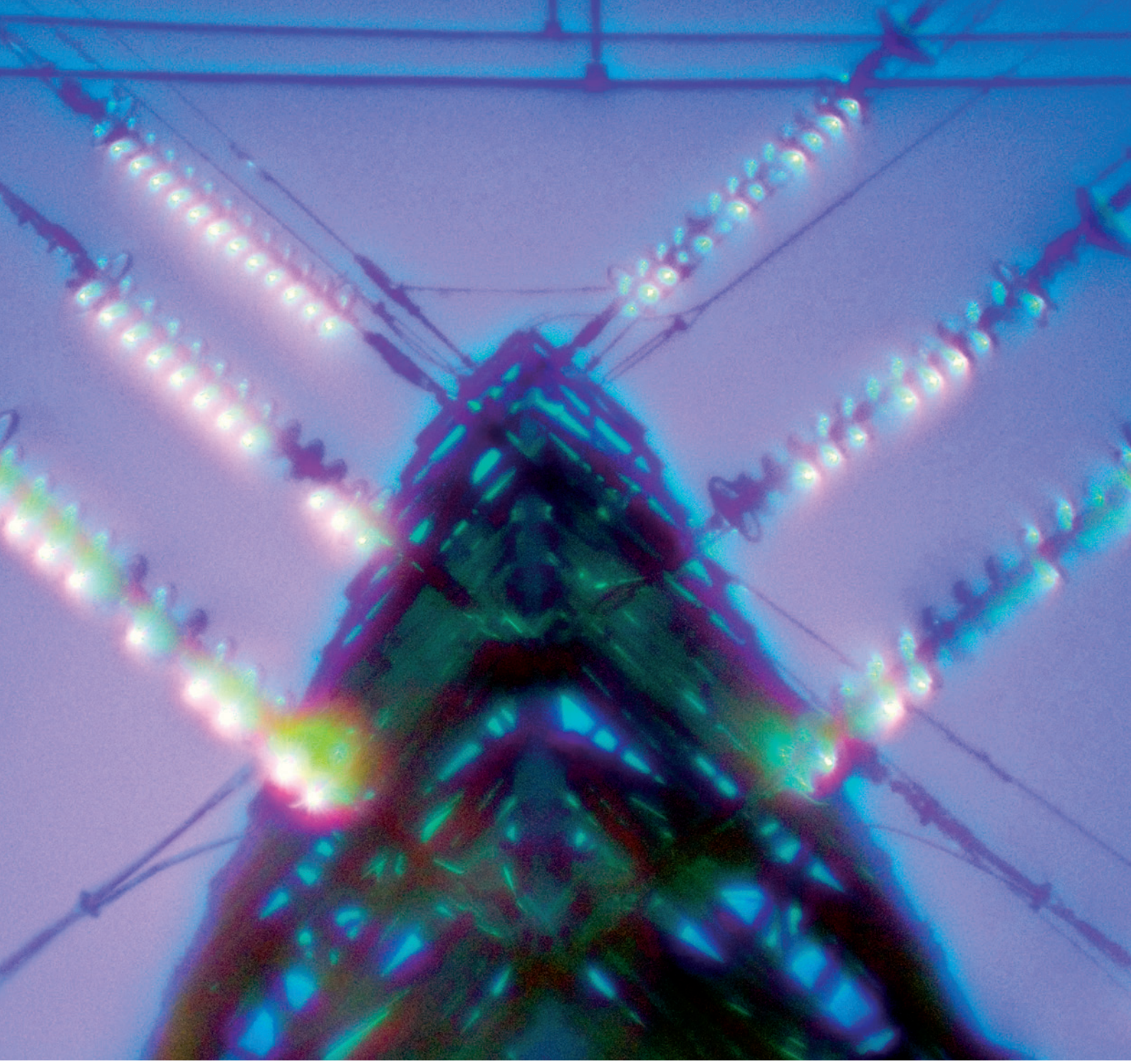

White Paper

Strategic asset management of power networks

Cover photo: Richard Kail/Science Photo Library

Executive summary

Electricity networks around the world are facing a once-in-a-lifetime level of profound challenges, ranging from the massive uptake of distributed generation devices, such as rooftop solar generation, through to significant changes in the control and communications equipment used in the network itself. Power networks in developed nations are struggling with an equipment base nearing the end of its lifetime, whilst those in developing nations wrestle with trying to identify best-practice examples on which to model their operations. Compounding these challenges, there is ever-increasing regulatory and funding pressure being placed on electricity network businesses to justify their management actions and expenditure decisions.

Amidst these challenges, there is great variation around the world on how electricity network companies approach what are arguably their number one challenge – the design, maintenance and operation of a large network of electrical equipment. Network companies often take quite different approaches in testing equipment, calculating the lifetime and financial costs of various equipment maintenance options, and even reporting on the performance of their system. The variety here is hardly intentional – it stems from a lack of internationally accepted global standards or guidelines on how to practice asset management in the electricity network sector.

This current lack of international standards or guidelines on asset management for electrical networks will have a significant impact on the reliability and future viability of the electricity sector.

Whilst standards such as the ISO 55000 series provide general guidance on best-practice asset management procedures, they do not provide the industry-specific guidance that is needed given the operational methods and challenges of the electricity transmission and distribution industry. The current situation means that:

- Network businesses around the world use different metrics to measure and report on the performance of their network. Without a commonly-accepted definition of ways to calculate (for example) failure rates, it is very difficult to benchmark across organizations or jurisdictions.
- There is a lack of consensus on what are best-practice methods for everything from testing the health of a particular item of equipment to prioritizing various asset management options. This makes stakeholder communication difficult (see below), and means many electricity network businesses waste time and resources developing their own methods to address a particular problem. This situation is particularly exacerbated in developing nations or in the context of relatively small organizations, who could benefit greatly by simply adopting best-practice methods developed by others.
- Without worldwide standards on measuring and reporting on electricity network asset management procedures and performance, broader stakeholder engagement is very difficult. When a network business cannot benchmark its performance against peers, or demonstrate that it is following industry-recognized best practice, stakeholders such as regulators or funding bodies can struggle to trust the network business's management decisions or appreciate the full depth of challenges ahead.

The present White Paper explores this issue in depth, examining the practice of asset management in the electricity power network sector and identifying areas of asset management practice that could benefit from international standards. These include:

- If common standards for reporting on the age and condition of assets existed, network businesses around the world could gain the confidence and trust of regulators, governments, and the public when staking funding applications based on the age and claimed upgrades of their equipment.
- Having standardized practices for asset management could significantly increase the trust and transparency around asset management and investment decisions for all stakeholders in the electricity power network industry, as everyone could refer to independently established guidelines for best-practice asset management.
- Having standards for asset management would allow network businesses to benchmark themselves against other organizations in different jurisdictions or geographies.
- Standards for asset management could be used as a communication and education tool to understand and explain the best-practice methods in asset management, in both developed and developing nations.

This White Paper was prepared following extensive industry consultation, with 3 international workshops being held around the world, attended by electricity network businesses, equipment manufacturers, research institutions and other standards organizations. These workshops focussed on identifying current asset management practices in the electricity power network sector and asking key industry representatives where they thought standards could make a contribution. In addition, 2 questionnaires were sent out to electricity network businesses, examining the current status of their assets (the equipment mix, age, etc.), and how they currently approach the management of these elements.

Electricity networks in many developed nations face the very significant challenge of an aging asset base. In many nations, electricity network rollout proceeded apace throughout the 1940s to 1980s but has slowed in recent years. Many significant items of equipment are now operating close to, or even beyond, their expected retirement age.

In many developed nations, the age of the asset base and the current slow rate of replacement mean it would take hundreds of years to renew all assets. This has significant reliability implications.

The aging equipment problem is not just one of equipment wear – it also constitutes a human resources issue, as in many cases the people with the skills and expertise to complete maintenance, or the experience needed to make asset management decisions regarding this older equipment, have retired from the industry. With an equipment fleet nearing the end of its life and a shortage of parts or people to maintain it, there are very significant implications for the reliability of electricity networks in many developed nations.

Whilst aging equipment may not represent such a challenge in developing nations, or in others with more recently installed networks, simply understanding the optimal path forward amidst a plethora of technologies, management options and an often challenging regulatory or funding environment can be very difficult.

Testing and maintenance procedures

The first area in which international standards can make a contribution is that of deciding what testing and subsequent maintenance practices a network business should follow in managing its network. Network businesses around the world take a variety of approaches with regard (for example) to testing the health of a transformer, all the way through to deciding which maintenance strategy (for example

time-based or risk-based maintenance) they wish to follow. Standards should not be used to mandate a particular approach, as it is important that network businesses be able to tailor their operations to their own particular circumstances. However, standards can be used to define best-practice methods for the various testing and maintenance options.

Defining performance metrics and reliability classifications

Whilst electricity network businesses around the world use similar-sounding performance metrics such as the system average interruption duration index (SAIDI), a measure of the average outage duration per customer served, the actual calculation of such metrics varies around the world. The situation worsens for measurement of non-technical impacts such as customer satisfaction, where vastly different indicators are used worldwide. Without a common calculation method, benchmarking the performance of different electricity networks and their asset management practices is very difficult. Standards could play a direct role here, specifying a range of performance metrics, technical and non-technical, and how these should be calculated. This would then introduce a common language to be used worldwide in the measurement and evaluation of electricity network performance and the impact of various asset management practices.

Standards could also be used to specify various reliability classifications for a network and the subsequent testing and maintenance outcomes needed to achieve such reliability classification. For example, standards might specify a “level 1” high-reliability network (for application to sensitive loads such as hospitals or semiconductor manufacturing facilities) and the requirements to achieve this classification, which may be quite different to those of a “level 3” lower-reliability network, where some level of outage can be tolerated.

With international standards specifying the requirements to achieve certain reliability classifications, electricity network businesses and their broader stakeholders will have a common understanding of the management practices and investment needed to realize these performance goals.

Asset management – evaluation and prioritization

With data on the health and various maintenance options available, another key role of asset management is to evaluate various options, the risks and returns of each, and then prioritize among them given constraints such as financial resources or equipment and personnel availability. Using a risk-based evaluation method, where the likelihood and consequences of (for example) a particular item of equipment failing is a common method used around the world to try and prioritize between various asset management options. Whilst the general approach may be common, the application of this approach varies significantly around the world – there are a wide variety of approaches to calculation of the risk matrix, and then how this is used in decision prioritization varies even more. Some of the more sophisticated approaches include estimation of the likely remaining life of a piece of equipment (based on historical data), and calculation of the future financial impacts of the various management alternatives. How these methods are implemented, and their various measures calculated, varies significantly. Standards can play a very significant role here, not necessarily mandating a particular approach, but providing references on the options available, and standardizing the calculation methods for each option, so that there is a common language and comparison is possible across businesses.

Fault databases and response options

The more sophisticated electricity network businesses maintain comprehensive historical databases of equipment items, and the type and number of faults that have occurred in them.

However, such databases vary significantly in the depth and breadth of content. Further, it is rare that network businesses have access to information from outside their business, and many smaller organizations may not have a sufficient amount of equipment to glean statistically valid information from their own database.

A centralized international database of electricity equipment failures and historical performance records would bring massive benefit to all stakeholders.

Such a historical database could facilitate the long-term tracking of faults, allowing industry to identify fault trends in particular items of equipment or particular usage scenarios. Similar databases have been used in the airline industry to identify systemic issues in a specific piece of equipment and prevent further catastrophic failures. Standards can play a key role here, by specifying which historical records should be kept and how.

Standards could also be used to provide exemplars of the range of responses to a particular equipment failure. With changing technology or innovative new approaches to equipment maintenance, many options may be available to a network business that they have not previously considered. By identifying common issues and the range of best-practice approaches to addressing them, standards can ensure that electricity network businesses are aware of their options, and can help them demonstrate to their broader stakeholders that they are following best practice.

Stakeholders for new standards

New asset management standards will be of significant benefit to a range of organizations related to the electricity power network industry. Whilst network businesses and their associated funding and regulatory organizations will be key beneficiaries, major equipment vendors will also benefit significantly. The manufacturers and maintenance contractors (references to "manufacturers" apply to both categories throughout the rest of this Executive summary) of major electricity network assets face many asset management challenges of their own. They must keep up with rapidly changing technology, whilst maintaining the equipment and personnel needed to support legacy equipment that is sometimes many decades old, and must additionally ensure that equipment is available to the end user, even though purchasing patterns in the power network sector can be very peaky. Furthermore, manufacturers must accomplish all of this while trying to operate a successful private business. Key to addressing these challenges is close communication between manufacturers and their customers, so that manufacturers can forecast future demand and plan their own business practices cognizant of industry needs.

Standards and internationally recognized guidelines can help manufacturers of electrical power network assets by ensuring a common language and data set regarding asset management patterns, failure rates and historical equipment performance.

The scope of new standards

Throughout the investigative phase of this project, network businesses, manufacturers and other electricity industry stakeholders were enthusiastic in supporting the preparation of additional standards on asset management, but also expressed caution regarding the scope of such standards. Electricity networks around the world vary significantly, both in their operations, and in the performance standards expected of them. In this case network businesses made clear that standards should not be overly prescriptive – network businesses should be free to choose the operations that suit their own situation.

Standards should not mandate one particular practice for electrical power network asset management. Rather, standards or guidelines should provide network businesses with a range of

well-defined options and allow them to choose the ones that best match their own circumstances and requirements.

Overall, there is a wide range of potential new standards or guidelines that could be prepared regarding asset management in the electrical power network industry. Areas covered by such standards include:

- Inspection and diagnosis methods and criteria for major equipment
- Measurement and reporting of fault and equipment failure data
  - Analysis methods, and common deterioration modes or faults for major equipment
  - Best-practice examples of remedial actions for major equipment, ranging from replacement to partial replacement or refurbishment
- Methods for lifetime estimation and reporting for major equipment
- Life cycle cost calculation
- Risk evaluation methods
- Calculation of health indices for major equipment
- Prioritization methods for asset management
- System performance indices (CAIDI, SAIDI, SAIFI, etc.)

The electrical power network sector is undergoing a period of profound change, and asset management remains the number one challenge for most network businesses around the world. There are very few international standards that define a common language and metrics around asset management in the electrical power network industry, or provide examples of best practice to guide network businesses and their broader stakeholders worldwide. Creation of new standards in the range of areas suggested above will be a long and challenging exercise, as the range of asset management practices currently in place varies significantly across geography and jurisdiction. Nonetheless, significant gains can be made here, and the IEC is encouraged to initiate this process as soon as possible.

Acknowledgments

This White Paper has been prepared by the Strategic asset management of power networks project team, under the IEC Market Strategy Board. The project team included representatives from electrical power network businesses, research institutes and equipment vendors from around the world. To seek broader input from a range of stakeholders, the IEC ran 3 workshops dedicated to this White Paper, in Tokyo (December 2014), Washington DC (February 2015) and Paris (April 2015). These workshops were attended by electricity network businesses, equipment manufacturers, research organizations and standards organizations, who were invited to detail how they currently approach asset management and where they thought standards or guides for electricity network asset management, could benefit their business. Lastly, the IEC project team ran 2 international surveys as part of this project, one asking electricity network companies from around the world for data on their existing asset base and the other soliciting information from them on how they currently approach asset management.

Workshop presenters and panelists

Ms. Edmea Adell, President, ASSETSMAN, Representative of ISO, France

Mr. Eric Andreini, Asset Management Senior Advisor, RTE, France

Mr. Jim Dieter, Head of US Delegation to ISO PC/251 for ISO 55000, US

Mr. Derrick Dunkley, New Technology Specialist, National Grid, UK

Dr. Hisatoshi Ikeda, Chairman of IEC ACTAD, Japan

Mr. Bernd Keller, Head of Solution Management, SAP AG, Germany

Mr. Rob Manning, Vice President Transmission, EPRI, US

Mr. Hirofumi Matsumura, Senior Director, SAP Japan Co., Japan

Mr. John McDonald, Director, GE Digital Energy, IEEE Fellow, US

Mr. Michael Moy, Director, Asset Performance and Investing Strategy, Commonwealth Edison, US

Dr. Tatsuki Okamoto, Executive Research Specialist, CRIEPI, Japan

Mr. Gerald Sanchis, French member of CIGRE WG C1.25, RTE, France

Dr. Yasuyuki Tada, Hitachi, Japan

Mr. Kyoichi Uehara, Chief Specialist, T&D Systems Div., Toshiba, Japan

Mr. Mark Waldron, Chairman of Technical Committee, CIGRE, UK

Contributors (responded to the surveys, gave comments to early draft report)

CLP Power, Hong Kong

Duke Energy, US

EDF, France

The Federation of Electric Power Companies of Japan

Fingrid, Finland

First Energy Corp, US

Portland General Electric, US

The Salt River Project, US

TenneT, Germany and Netherland

Terna, Italy

Project team members

Mr. Toshiro Takebe, Project Leader, IEC MSB Member, TEPCO

Dr. Glenn Platt, Project Partner, N.OGEE Consultants

Mr. Peter Lanctot, Secretary, IEC

Mr. Yoshiro Asami, TEPCO

Dr. Per Lund Christer, DNV GL

Mr. Achim Krueger, SAP

Dr. Bess Yi Fung Ng, DNV GL

Mr. Zoltan Nochta, SAP

Mr. Hiroki Shigetsugu, TEPCO

Mr. Alan Southall, SAP

Mr. Yoshimitsu Umahashi, TEPCO

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List of abbreviations

Technical and scientific terms

ACRM	alignment, capability, resources, motivation
APC	availability percentage
CAIDI	customer average interruption duration index
CBM	condition-based maintenance
CIM	common information model
CM	corrective maintenance
EBITDA	earnings before interest, taxes, depreciation, and amortization
FMEA	failure mode and effects analysis
IROL	interconnection reliability operating limit
NEL	non-entry level
OHL	overhead line
PAS	publicly available specification
PCB	polychlorinated biphenyl
RCM	reliability-centred maintenance
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SOL	system operating limit
TB	technical brochure
TBM	time-based maintenance
XLPE	cross-linked polyethylene

Organizations, institutions and companies

BCTC	British Columbia Transmission Corporation
CEER	Council of European Energy Regulators
CIGRE	Conseil International des Grands Réseaux Electriques (International Council on Large Electric Systems)
ComEd	Commonwealth Edison

EDF	Electricité de France
GFMAM	Global Forum on Maintenance and Asset Management
IAM	Institute of Asset Management
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
ISO	International Organization for Standardization
KEMA	Keuring van Elektrotechnische Materialen te Arnhem
MSB	Market Strategy Board (of the IEC)
NGET	National Grid Electricity Transmission, Great Britain
OFGEM	Office of Gas and Electricity Markets, Great Britain
SMRP	Society for Maintenance and Reliability Professionals

Glossary

asset

a major item of electrical network equipment, such as a circuit breaker, overhead line, transformer or underground cable

cable

a high capacity electrical conductor, buried underground and used as an alternative to overhead lines for electricity transmission or distribution

circuit breaker

an automatically operated electrical switch that protects a segment of the electrical network from damage caused by electrical faults

NOTE Common types of circuit breaker are air, oil or gas circuit breakers, all being identical with the same ultimate function, but varying in how they go about interrupting the flow of electricity.

conductor

a wire that carries electricity along its length

distributed generation

electricity generation, often relatively small, located close to the particular load to which it supplies power

distribution

except when the standard dictionary definition applies, transfer of electricity between transmission supply points (typically substations) and individual customers

electrical network

an interconnection of electrical components. In the context of this White Paper, the electrical network is the system of components such as overhead lines, cables, transformers and circuit breakers linking electrical generators and loads such as houses, buildings and factories

high voltage

any voltage between 69 kV and 230 kV or having a value above a conventionally adopted limit

NOTE An example of high voltage is the set of upper voltage values used in bulk power systems.

network

see electrical network

network business
network company
network operator

organization that is responsible for the maintenance and operation of an electrical network

outage

period when an electricity generator, transmission network or related resource is out of service

overhead line

structure used to carry electrical energy large distances, consisting of electrical conductors suspended by large towers or poles

photovoltaics
PV

technology that converts energy from the sun directly into electricity

power system
power network

see electrical network

switchgear

generic term for devices such as circuit breakers

transformer

a device that reduces or increases the voltage of electricity in an electrical network

transmission

transfer of high-voltage electricity from where it is generated to the point at which it is transformed into a lower voltage for distribution or consumer supply

utility

see network operator

voltage

one of the key characteristics of an electrical device. A measure of its electric potential difference to some reference

Section 1

Introduction

The management of disparate, complex and distributed assets is one of the main challenges facing the electricity network industry. Unfortunately, asset management practices around the world vary significantly in their approach as well as in the language and metrics used. This causes similar variation in the quality of asset management practices and the benefits these practices bring to the business.

Given the current variability in asset management approaches, there is a significant opportunity for standardization activities to improve the approach and results of electricity network asset management. International standards put in place by organizations such as the ISO or IEC can ensure that multiple entities, from businesses to company executives and engineers use the same language and metrics when discussing asset management practice. Standards can also be used to detail the state of the art in particular asset management approaches, assisting those new to the area and easing the relative comparison of practices between organizations.

According to ISO 55000:2014, benefits from asset management include:

- Improved financial performance
- Informed asset investment decisions
- Managed risk
- Improved services and outputs
- Demonstrated social responsibility
- Demonstrated compliance
- Enhanced reputation
- Improved organizational sustainability
- Improved efficiency and effectiveness

When surveyed by the IEC, electricity network businesses listed the benefits of asset management to their business as including:

- Operational
  - Better asset knowledge
  - Guided long term investment planning
  - Long term resource needs are identified
  - Targeted performance goals more reachable
  - Allows the preparation of asset sustainment plans
- Financial
  - Rate/funding submissions are more defensible
  - More planned costs – less reactive costs
  - Better scenario planning decision transparency

Figure 1-1 shows a conceptual model of asset management [1]. Asset management strategy and planning and asset management decision making (in the middle of Figure 1-1) are the core practices of asset management, utilizing input from the organizational strategic plan and asset knowledge systems.

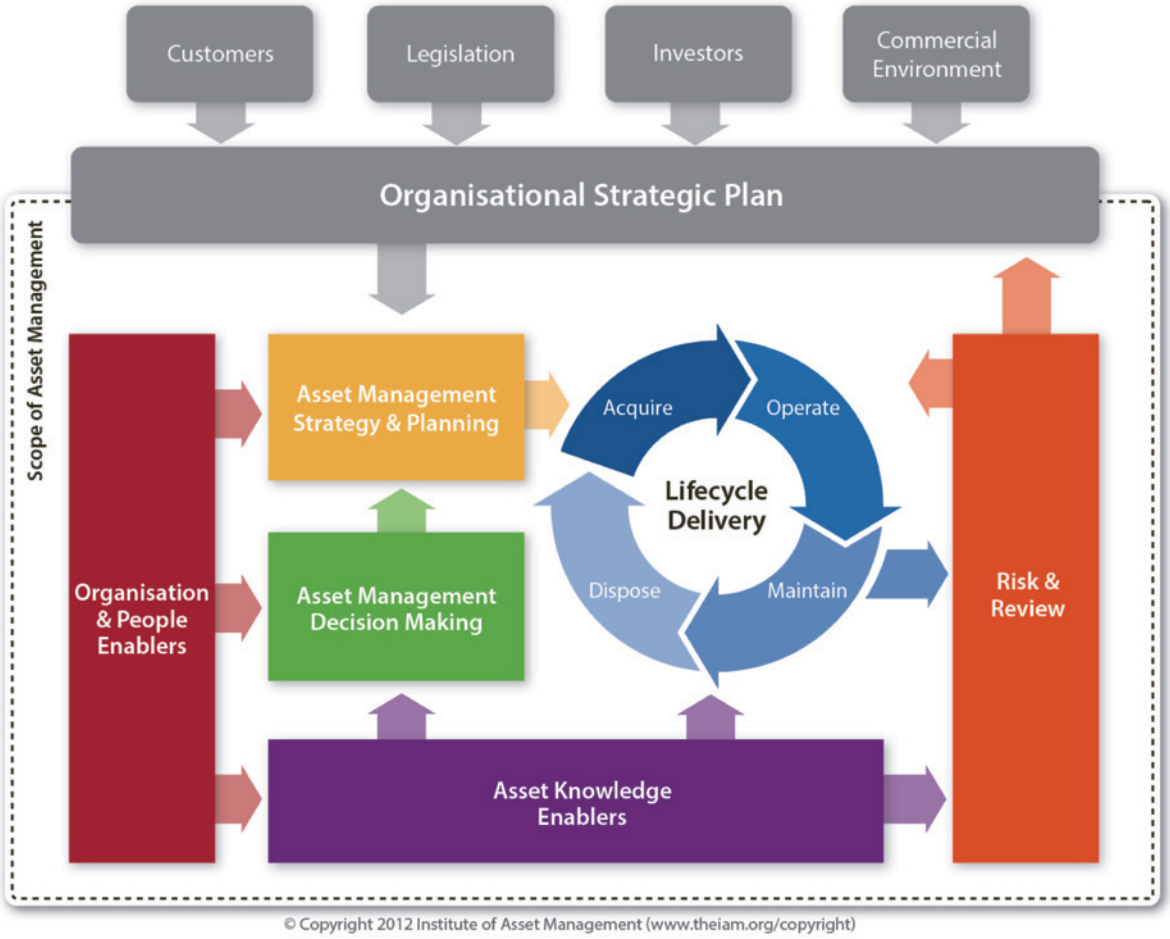

Figure 1-1 | Asset management conceptual model [1]

Standards or industry guides can play an important role in all of the asset management practice steps shown in Figure 1-1. The present White Paper explores this issue, examining where standards or industry guides can benefit electricity networks in how they approach and execute asset management in their business. Section 2 describes the current asset situation of electricity networks, and some of the significant risks these networks currently face. Sections 3 to 5 describe current electricity network asset management practices and explore where standards may assist. Section 6 considers where IEC International Standards on asset management may fit among other existing standards, and Section 7 presents conclusions and recommendations.

This White Paper draws on information from a range of sources. In addition to existing IEC and ISO International Standards on asset management, the White Paper also references a range of technical brochures from CIGRE, the International Council on Large Electric Systems. To seek input from stakeholders around the world, the IEC ran 3 workshops dedicated to this White Paper in Tokyo (December 2014), Washington DC (February 2015) and Paris (April 2015). These workshops were attended by electricity network businesses, equipment manufacturers, research organizations and standards organizations from around the world, who were asked to present details on how they currently approach asset management and where they thought standards or

guides for electricity network asset management could benefit their business. Lastly, the IEC project team also ran 2 international surveys as part of this project, one asking electricity network companies from around the world for data on their existing asset base, and the other soliciting information from them on how they currently approach asset management. These surveys, and their results, are detailed throughout this White Paper.

Section 2

Current status

2.1 Overview of the market

In many developed nations, construction of electricity grids advanced rapidly throughout the 20th century, matching a continual growth in demand and spread of electrification. Today, in many of these developed nations, demand growth has slowed dramatically or stopped, and traditional electricity network businesses, or business practices, face significant challenges involving a variety of pressures ranging from new types of distributed generation, such as solar photovoltaics, to increasingly peaky loads and regulatory pressure on reducing expenditure. These changing forces are having a profound impact on the makeup of the electricity network assets.

Figure 2-1 details the age distribution of various electricity network assets as described in CIGRE Technical Brochure TB 176 [2] in 2000. It can be seen that the amount of equipment installed in 1998 (time "0-5" in the figure) was half that installed 20 to 35 years before (constructed in the period 1963–1978).

More recently, in the early 21st century, some markets have grown again, due less to demand growth than to changes in the generation mix in these markets and the need for new transmission and distribution infrastructures associated with new generators.

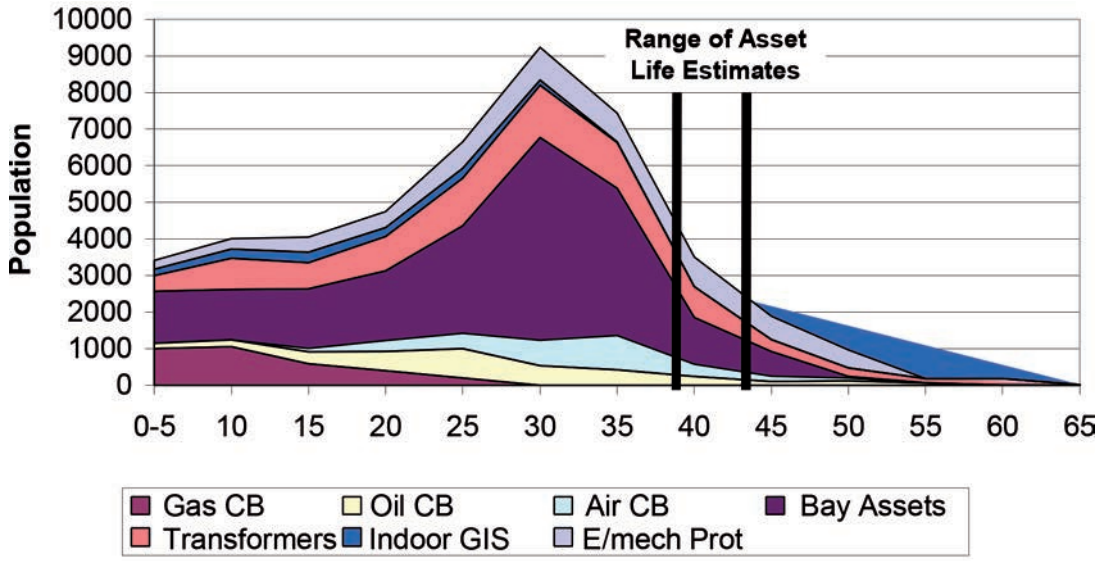

Figure 2-1 | Age distribution of various substation facilities [2]

Figure 2-2 [3] shows that electricity demand growth in the US has been slowing since the 1950s.

Figure 2-3 [4] shows historical and planned transmission construction in the US. It illustrates a steep decline from 1970 to 2000, which contributed to an increased incidence of weather-related power outages, according to a White House report [5].

As part of this project the IEC ran a survey of international electricity network businesses to get a snapshot of the age of their electricity network assets. The results from the survey varied significantly across countries, and could be loosely grouped according to developed countries with a relatively old asset base (such as the US, Australia, Japan) and developing nations with a relatively young asset base.

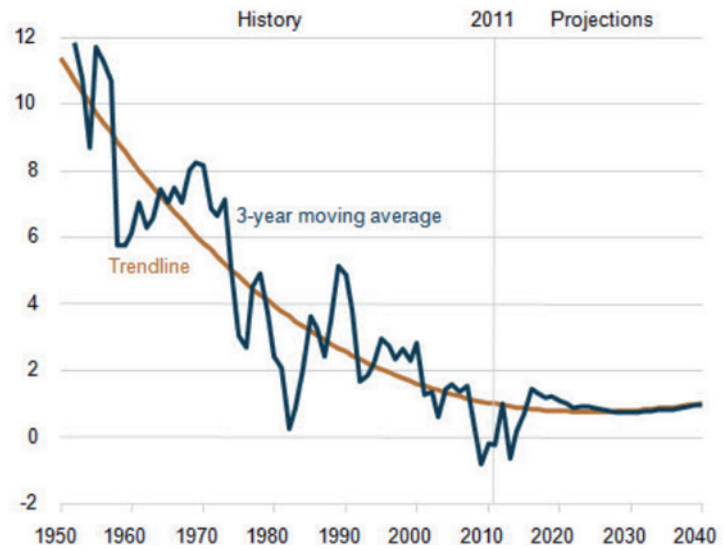

Figure 2-2 | US electricity demand growth, 1950-2040 (percent, 3-year moving average) [3]

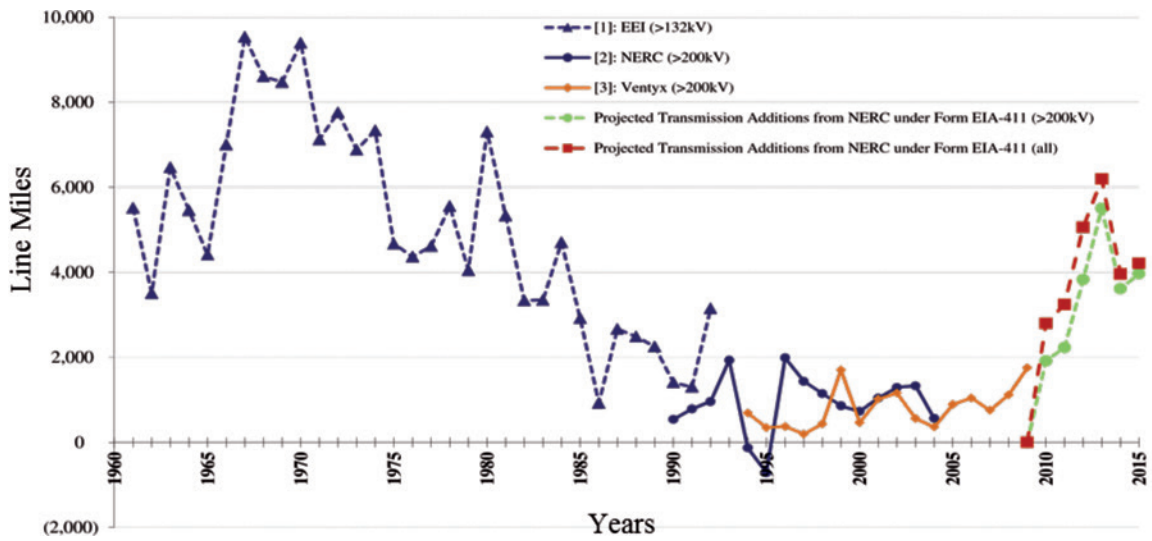

Figure 2-3 | Transmission construction activity in the US [4]

Figure 2-4 shows a relatively young distribution of substation transformer ages from a developing country. Conversely, despite recent construction activities, many of the assets in developed countries remain quite old, and have not been upgraded or refurbished, as shown in Figure 2-5. Nevertheless, a few developed countries are proceeding apace with equipment upgrades and refurbishment, as shown in Figure 2-6. Figures 2-4, 2-5 and 2-6 are based on data collected by the project team through electricity network operator surveys.

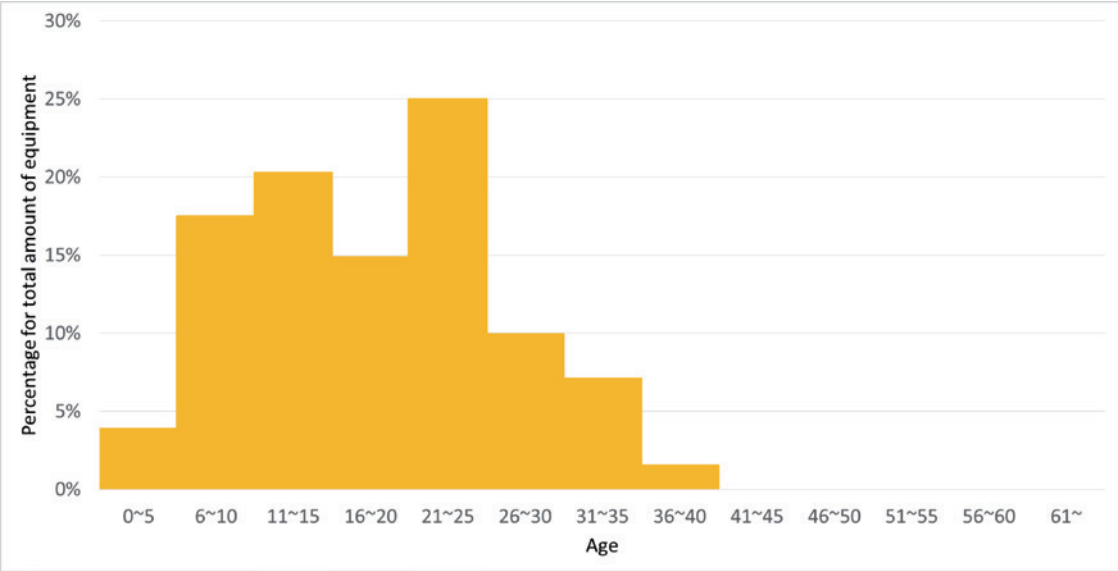

Figure 2-4 | Typical electricity network asset age distribution for many developing nations

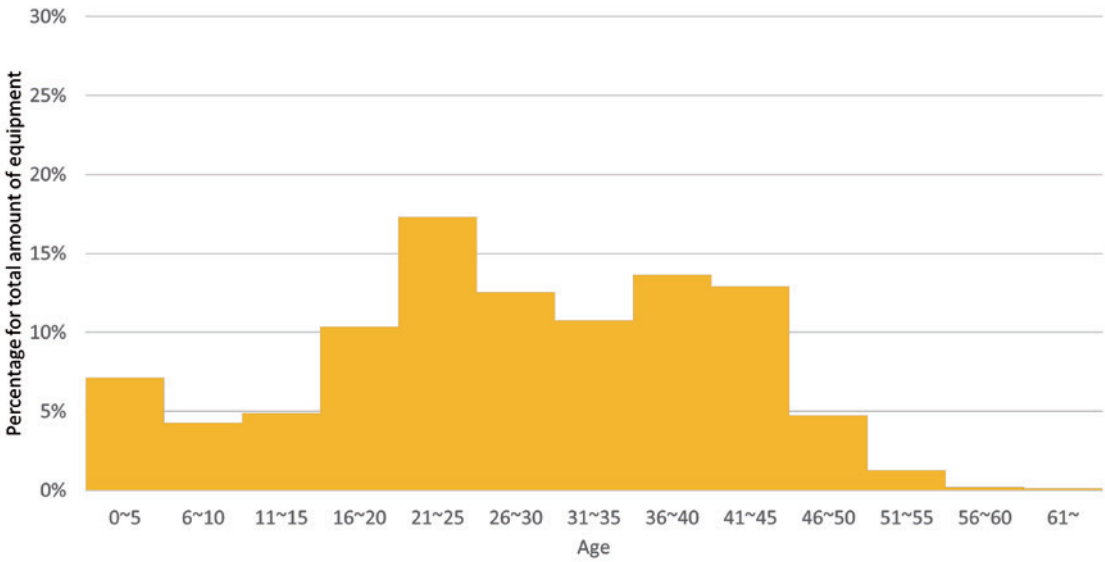

Figure 2-5 | Typical electricity network asset age distribution for many developed nations

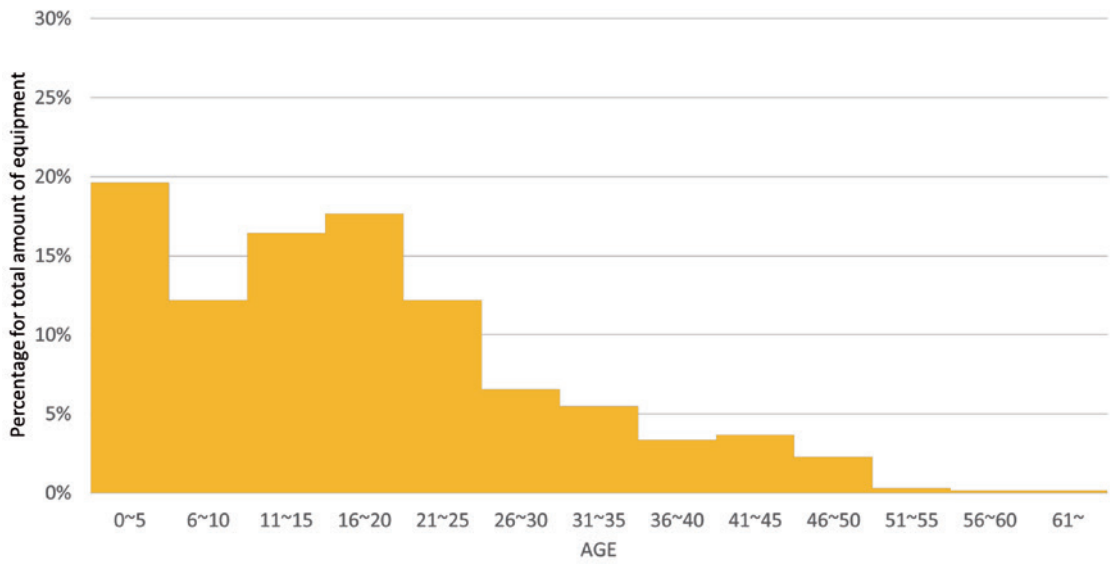

Figure 2-6 | Typical electricity network asset age distribution in developed nations installing new equipment

2.2 Lifetime considerations

Given the age statistics in the previous sub-section, in many countries the pace of equipment upgrades significantly lags behind the amount of aging equipment that is approaching end of life. In some countries, at the current rate of replacement, it would take several hundred years to replace all the aged equipment. On the other hand, the replacement of aged equipment has proceeded comparatively rapidly in other countries. Table 2-1, based on data on electrical asset ages collected by the project team, shows estimated years to replace, obtained by dividing the amount of equipment by the yearly number of replacements.

Table 2-2 shows the results of a questionnaire on the service life of various types of electricity network equipment, collected in CIGRE TB 176 [2]. It can be seen that based on the current replacement rates of many electricity network businesses, many items of equipment will not be replaced until long after their expected service life.

Table 2-1 | Estimated years to replace aged assets from 5 electricity network businesses

	OHL wire	Tower	Cable	Transformer	Switchgear
Utility A	47	399	112	110	80
Utility B	68	178	278	93	45
Utility C	758	179	63	124	172
Utility D	276	327	n/a	59	41
Utility E	96	174	42	49	47

Table 2-2 | Asset life estimation [2]

Plant type	System voltage (kV)	Mean and range of asset life estimates (years)	Standard deviation (years)	Reason for asset life variances
Circuit breakers				
Air	110-199 200-275 ≥345	**41** (30 to 50) **41** (30 to 50) **40** (30 to 50)	6 6 6	Rating requirements, fault duty changes, maintenance costs, spares obsolescence, mechanical wear, safety, seal problems
Oil	110-199 200-275 ≥345	**42** (30 to 50) **41** (30 to 50) **38** (30 to 45)	6 6 5	Rating requirements, fault duty changes, maintenance costs, spares obsolescence, mechanical wear, safety, seal problems
Gas	110-199 200-275 ≥345	**43** (30 to 50) **42** (30 to 50) **42** (30 to 50)	6 6 6	Rating requirements, fault duty changes, maintenance costs, spares obsolescence, mechanical wear, safety, seal problems, seen as “less robust”, environmental concern re SF6
Bay assets				
Earth switches and disconnectors	≥110	**42** (30 to 50)	8	Rating requirements, maintenance costs, corrosion, mechanical wear
CTs-Oil	≥110	**39** (30 to 50)	7	Design weaknesses, seals
CVT’s	≥110	**39** (30 to 50)	7	Moisture ingress, PCB contamination of oil
Transformers	≥110	**42** (32 to 55)	8	Design, loading, insulating paper and oil degradation, system faults, spares, rating requirements, high temperature, moisture levels
Indoor GIS	≥110	**42** (30 to 50)	8	Rating requirements, fault duty changes, maintenance costs, spares obsolescence, mechanical wear, safety, seal problems, environmental concern re SF6
Electro-mechanical protection	–	**32** (20 to 45)	9	Wear, contact erosion, reliability, verdigris, temperature extremes, skilled labour, spares, functionality, system design changes
ACSR-OHL				
“Normal” environment	≥110	**54** (40 to 80)	14	Climate, environment, corrosion, conductor grease levels, creep, mechanical fatigue, insulator failures, wind, precipitation, ice loading, pollution levels, material quality, high temperatures due to loading, joint, design
”Heavily polluted”	≥110	**46** (30 to 70)	15	
Towers				
Steel lattice	≥110	**63** (35 to 100)	21	Climate, environment, corrosion, maintenance, poor galvanizing, ground conditions, concrete spalling, grillage corrosion, steel/concrete junction
Wood poles		**44** (40 to 50)	4	Preservation treatment, rot, woodpeckers, insects, wind, precipitation
Cables				Environmental concerns (oil leaks), backfill, sheath (oil reinforcing tape) corrosion, electrical/ thermomechanical stress, loading, crystalline lead sheath
Oil filled	≥110	**51** (30 to 85)	20	

2.3 Financial considerations

The challenges of aging equipment and a relatively slow replacement rate are not only technical – they also have very significant financial implications. Whilst it is difficult to directly convert statistics on asset ages into reliability impacts or electricity outage forecasts, it is intuitively deducible that improper asset management will eventually result in additional outages, and that such outages have significant cost.

For example, consider the macro analysis from the White House paper [5] mentioned previously, which also lists estimated costs of weather-related power outages in the US (Figure 2-7). There is considerable variation in the estimations, but typically costs amounting to tens of billions of US dollars have been associated with such weather-related outages.

Another example is a microanalysis from the British regulator OFGEM that details a reliability incentive in the license document for NGET, British network operator. The incentive specifies "…value of lost load which has the value GBP 16 000 per MWh (in 2009/10 prices)."[6]

2.4 Key asset management challenges

When reviewing the fleet of electricity network equipment around the world, 4 significant asset management challenges exist:

1) A lot of equipment was constructed in the 20th century, remains in service and will soon be operating beyond its designed life.
2) Even if older equipment is performing well, obtaining technical support or spare parts for equipment designed and manufactured decades ago can be very difficult.
3) In many cases, at the current rate of replacement, it would take several hundred years to fully replace existing old equipment.
4) Because of the large amount of old equipment, there is a significant risk of multiple failures occurring simultaneously, more than many electricity network businesses would be equipped to handle.

These challenges pose significant risks when it comes to power quality and reliability of supply. For this reason, business decisions on how to

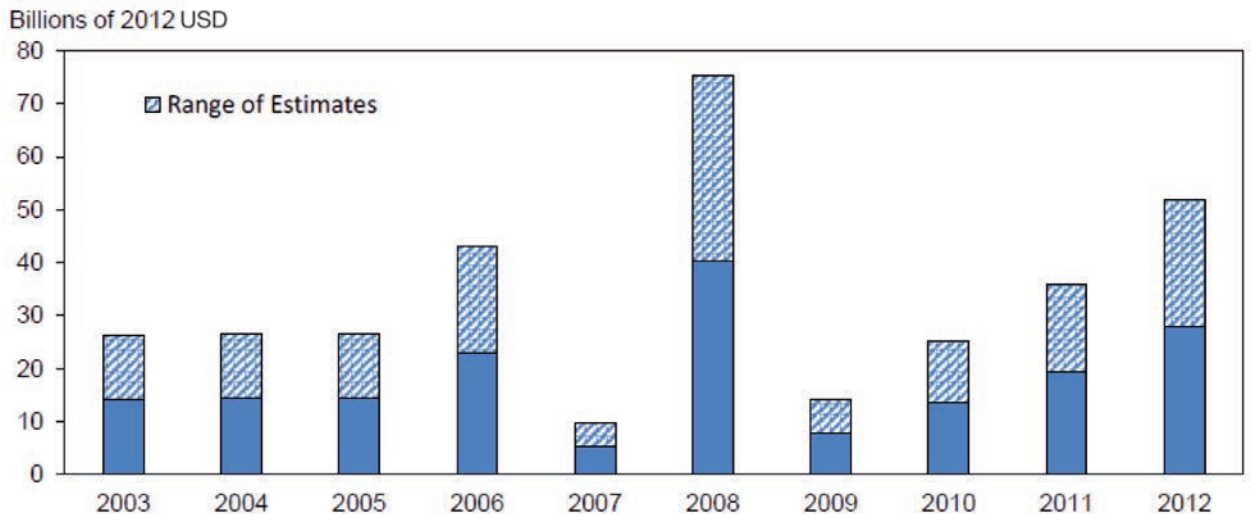

Figure 2-7 | Estimated costs of weather-related power outages in the US [5]

proceed with the updating and maintenance of equipment remain one of the largest challenges for today's electricity network businesses. These issues aren't just a problem for electricity network businesses – they pose a significant challenge for equipment vendors and other industry stakeholders, who need to maintain supply chains, production capacity and expertise and a viable commercial operation.

Unfortunately, due to a diversity of approaches, nomenclature and metrics, asset management practices around the world vary significantly, and in many cases electricity network operators are left to determine themselves how to proceed, with little guidance from the broader industry. When, investigating this further, the project team surveyed electricity network stakeholders regarding their current assets and management practices, the stakeholders listed their key asset management challenges as:

1) The unavailability of international specifications on maintenance
2) The lack of uniformity in equipment replacement criteria across industry
3) The difficulty in finding people with the right skills to maintain and manage aging equipment
4) The management of aging equipment
5) Deciding how to invest across a range of priorities

2.5 Traditional asset management and asset management in the future

Whilst significant benefits could be gained from simply unifying asset management practices across the world's electricity network operators, asset management practices themselves are continuously advancing. At the IEC MSB workshop on asset management in Washington DC, Commonwealth Edison of Chicago gave the following summary of traditional asset management vs. the next generation of asset management.

1) Traditional asset management
   a) Estimation of failures from historical performance data based on intuition and experience
   b) Bias towards management programmes that address the entire population of an asset/component, not taking into account individual asset condition and risk/criticality
   c) Limited view of system and component health; no consistent/repeatable process to measure
2) Next generation asset management
   a) Broad view of system and component condition; standard repeatable process
   b) Based around scoring the health of individual assets in each class – for example, transformers, poles, underground cable, and providing a fact-based input into the probability of failure of individual assets
   c) Potential to direct maintenance-based individual assessments of asset health – for example, giving the opportunity to target populations of assets in fair condition to mitigate/slow degradation
   d) Coupled with risk assessment, the possibility to target work on particular individual assets in poor condition and which are situated in such a way that they represent a significant risk to the system

Section 3

Asset management metrics

The broad practice of asset management can be broken down into 3 separate functions. As shown in Figure 3-1, which was elaborated from information in CIGRE TB 422 [7] and CIGRE TB 597 [8], the key functions include:

1) The asset owner, who sets a goal for improving the value of the entire company
2) The service provider, who furnishes on-site operational functions such as data collection and asset maintenance
3) The asset manager, who plays the role of unifying these 2 groups

Based on a review of CIGRE TB 541 [9], asset management can be classified as follows.

- Condition assessment and asset monitoring
- End of life issues
- Asset management decision making and risk management
- Grid development
- Maintenance processes and decision making
- Collection of asset data and information

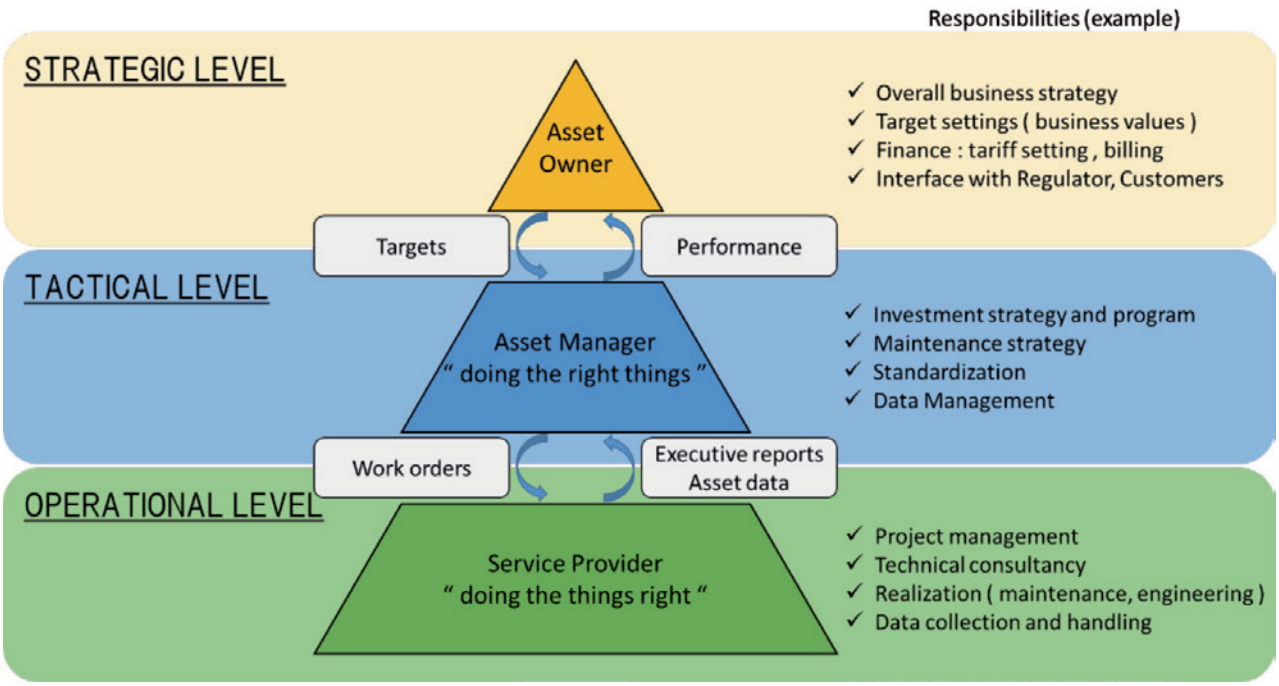

Figure 3-1 | Asset management functions and information exchange [7] [8]

When considering the practice of asset management, the workflow can be broadly described as below:

1) Construct and operate the equipment
2) Prepare the equipment database
3) Inspect/diagnose the equipment
4) Equipment abnormality/accident occurs
5) Investigate the cause of an abnormality/ accident, investigate the deterioration mode
6) Prepare the abnormality database
7) Formulate action plans in consideration of the equipment service life
8) Carry out comparative reviews of the proposed measures, and make a decision on which measure to take, whilst considering any limiting financial conditions

Often, a third-party service provider carries out actions 1) to 7) for the asset manager. Action 8) is carried out by the asset manager himself on the basis of the conditions provided by the asset owner.

Currently, a range of IEC International Standards exist related to electricity network equipment, such as:

- Voltages and durations of high voltage tests – for example, a voltage test is specified as "318 kV for 30 min" for 220-230 kV cable (IEC 62067)
- Material tests on chemical, mechanical, and electrical properties, including both test methods and evaluation criteria – for example, elongation at breaks is 200% for XLPE material (IEC 62067)
- Value of physical parameters – for example, the resistance of a copper conductor of 1 000 mm^2 is 0,0176 W/km or below (IEC 60228)
- Calculation methods of transmission capacities – for example, cable conductor temperature is calculated using the following equation (IEC 60287 – details are omitted here as the purpose is to show how precisely IEC specifies designs):

$$\Delta\theta = (I^2 R + \frac{1}{2} W_d)T_1 + [I^2 R(1 + \lambda_1) + W_d]nT_2 + [I^2 R(1 + \lambda_1 + \lambda_2) + W_d]n(T_3 + T_4)$$

These IEC International Standards are typically used when electricity network businesses purchase products from manufacturers or during system design. Few IEC International Standards consider electricity network asset management. Indeed, only one well-known IEC International Standard focuses on asset management, IEC 60599, covering dissolved gas analysis of transformers. Other than this testing, there is little to guide electricity network operators regarding the technical aspects of asset management. Instead they are left to determine by themselves what to test, how often and what criteria to accept. Furthermore, broader stakeholders such as governments, regulators and the general public are left to simply trust electricity network businesses regarding how such decisions are made.

3.1 Asset monitoring and maintenance

One of the key functions of an asset management service provider is how to monitor the condition of assets, and then manage their maintenance. Large electricity network businesses may spend the equivalent of hundreds of millions of USD inspecting, testing, refurbishing and replacing assets. How such funds are spent, what test procedures are followed, how to interpret the results of such tests and then what maintenance options are available are all factors that once again vary considerably across electricity network businesses around the world.

Sections 5.2.1 to 5.2.2 of CIGRE TB 422 [7] describes the advantages of regular and carefully planned inspection, as shown in Figure 3-2. Careful, regular inspections then allow for well-planned maintenance, as opposed to reactionary maintenance that occurs without regular inspection.

Whilst it is recognized that regular inspections carry great value, unfortunately the way these inspections are carried out varies significantly around the world. Table 3-1 gives a list of inspection items for cables by 10 different electricity network operators from different parts of the world (CIGRE TB 279 [10]). Other examples are summarized in Annex A.

Figure 3-2 | The maintenance chain of impact [7]

Table 3-1 | Maintenance items on cables from 10 different electricity network operators [10]

	No. 1	No. 2	No. 3	No. 4	No. 5	No. 6	No. 7	No. 8	No. 9	No. 10
Patrol of cable routes	Every 2 months	Currently by special people		Check for civil work, cable markers are visible	Annually	Annually	6-monthly	Monthly for checking of environment activity (only for important circuits)		
Inspection of warning signs					Annually	Annually		Annually: knowledge of environment modification		Warning sign is not used
Administrative procedure, to provide information on cable routes to contractors					Yes, national	Yes, national				Yes
Pressure monitoring, alarm	Yes	Yes					Yes	Yes	Yes	Yes
Pressure readings	Every 2 months	Monthly		Yes		Every 2 years	Monthly	Every 3 or 6 months	Every 2 months	50 kV: every 6 months 132 kV: every 3 months
Alarm gauge check SCFF + GC	Every 3 years	Every 3 months			Annually	Yearly		Every 1, 3, or 6 years	Annually	50 kV: every 6 months 132 kV: every 3 months
Inspection for corrosion	Every 3 years	Annually	Annually		Annually, only on gas pressure cables	Yearly on gas pressure cables on FF cables protection of tank is controlled	Every 6 months	Only on terminations every 3 or 6 months		
Sheath test (serving test)	Every 3 years	Annually	Annually	Yes		Annually in city, else every 2 years	Annually	Condition-based		
Check of thermocouple				Yes				Yes		
Visual inspections of terminations	Every 3 years			Check for external damage, dielectric fluid leakage, oil level and connections to overhead lines		Annually		Every 3 or 6 months	Annually	50 kV: every 6 months 132 kV every 3 months
Cleaning and treatment of outdoor termination				Yes						
Visual inspection of oil tank	Every 3 years							Every 3 or 6 months	Annually	
Analysis of cable oil	Every 3 years									
Test of earth resistance								Every 6 years		

As can be seen, even for the same items of equipment, inspection methods can vary significantly in both approach and frequency. For example, some network businesses will inspect tanks every 3 months, whilst for others such inspections are performed every 6 years. In another example, some network businesses patrol cable routes every 2 months, whereas for others this only occurs annually. Similarly, how to interpret the results of an inspection (whether an item needs maintenance) varies significantly across network operators. Ultimately, a lack of standards for condition monitoring means electricity network businesses around the world have adopted a variety of approaches, and it is far from clear what best practice is. Even though manufacturers can furnish asset managers suggested maintenance procedures, such suggestions often vary between manufacturers. It is for this reason that, when surveyed (as mentioned in Section 2-4), network businesses cited the fact that "there exists no international specifications on maintenance" as one of their key challenges. This is particularly surprising when contrasted with the well-accepted standards for material specifications, testing methods, testing frequency and quality measurement that exist for manufacturing cables, covered in detail by the IEC.

Having established asset monitoring procedures, the next step is to use the data that flows from these procedures and decide how to maintain the electricity network assets. Again, there are a wide variety of possible approaches to asset maintenance. Some of those described in CIGRE TB 309 [11] include:

- Corrective maintenance (CM) – the most simple maintenance strategy. The component is operated until it fails. After failure, the component condition is assessed to make a decision whether to repair or replace.
- Time-based maintenance (TBM) – the traditional approach and still widely used today. Fixed time intervals for inspection and for certain routine maintenance work are established.
- Condition-based maintenance (CBM) – the maintenance activity is triggered by the estimated condition reaching certain thresholds. Leads to high availability with moderate maintenance costs.
- Reliability-centred maintenance (RCM) – the maintenance schedule is optimized by considering 2 aspects: the condition of the equipment and the importance of the equipment for the network.

These approaches all vary significantly, and their relative merits are still under investigation by industry. However, here again the variability causes challenges for all stakeholders – it is difficult for asset managers or broader stakeholders to compare results across organizations using disparate asset maintenance approaches, etc.

Consider for example a real-world problem of disparate maintenance approaches. The majority of cable accidents are caused by cables being damaged during construction (for example, of a road) by a third party (CIGRE TB 358 [12]). Two different approaches to addressing this issue could be adopted:

1) An example of best practice: patrols are introduced along the road's proposed path, and an agreement is established with the contractor charged with excavating the road on how the risk of cable damage will be managed.
2) An example of poor practice: the company involved does not engage in any pro-active measures to prevent external cable damage in this situation (CIGRE TB 279 [10]).

Standards can be used in such a situation not to mandate a particular practice (such as requiring an inspection), but rather to define particular goals, as it is important to allow a degree of diversity in approaches to asset management, with companies determining their own methods of achieving the goals set. In the example above, routine inspection may not be necessary if there exists an online monitoring system equipped

with real-time alarms, and either approach could achieve similar goals.

Ultimately, standards can bring significant benefits without actually forcing all companies to use the same inspection items, frequency, methods or acceptance criteria, which are customized items best tailored to individual situations. Rather, standards could be used, for example, to define reliability classes, and under these classes, various degrees of inspection frequency and other metrics can be specified. With various reliability classes defined, companies can then select which reliability class they wish to operate in, and can compare their practices to those in the same class, whilst still allowing variability across deployments around the world.

3.2 Faults and deterioration modes

Another critical part of any electricity power network business is managing equipment faults or major accidents. Modern fault and accident analysis approaches include the key steps of investigating the fundamental cause of the accident (root cause analysis), identification of the abnormal modes and then development of an understanding of the fault on the equipment's lifetime. If such approaches are not taken, responses to major faults or accidents tend to be made on an ad-hoc basis, without exploring the fundamental cause, which usually results in greater losses in the long run. For example, consider a situation in which a cable has been developing numerous faults. There are 2 possible scenarios for addressing the situation:

1) An example of best-practice: in managing the situation, the responsible electricity network business explores the cause of the accident. The manufacturer insists that the cable must be having issues due to an installation error, and therefore other cables of identical construction have been left intact. The electricity network business, suspicious as regards the number of faults, performs their own investigation by inspecting many cable sections. This investigation determines that the root cause of the faults lies not in installation damage but in the cable itself. With this insight, the network business replaces all cables and thus prevents future major accidents.
2) An example of poor practice: the electricity network business does not work to investigate the root cause of the cable faults, but instead acts reactively, digging up the cable and splicing it into new sections as faults occur. Ultimately, following all of the repair work, the line ends up composed of many spliced cables and connection parts, and the remaining original cable parts account for only a very small proportion of the original line. It would cost much less, and result in far fewer outages, if the cable were thoroughly inspected and the root manufacturing defect identified from the beginning.

In this example, standards could help by specifying common methods of fault investigation or the common number of outages of a particular cable construction and installation, thereby assisting the determination of the root cause of faults that have been identified. Whilst such standards would need to be general in order to cover a range of equipment practices and manufacturers, they would still be of great guidance and value on best-practice.

Standards also have a role to play in faults that occur from general equipment deterioration. In this case, maintenance and replacement plans often try to forecast and extrapolate the deterioration rate of major items of equipment. Standards can bring significant benefits here – for example, standards could specify particular deterioration modes and rates for equipment, thereby allowing electricity network businesses to estimate the remaining life of an asset, and could perform relative comparisons on how various maintenance strategies affect deterioration rates. Annex B provides detailed examples of deterioration modes for various common electricity network major assets.

3.2.1 Definition of service life

Whilst deterioration is one major factor in determining the service life of a piece of equipment, it is not the only one. There are a range of other considerations that effect service life. Some of those suggested in Chapter 7 of CIGRE TB 422 [7] include:

- Safety
- Reliability
- Maintenance cost
- Capacity shortage
- Exhaustion of parts
- Influence on the environment
- Human resources
- Manufacturer's support
- Aging
- Obsolescence

For example, whilst still functional, a piece of equipment may be determined to have reached the end of its service life, because it is simply too expensive to maintain or because appropriately trained personnel with familiarity about this equipment are no longer available.

Ultimately, having a common understanding of how to measure and determine the service life of a particular piece of equipment is a critical part of the business between asset owners, managers, and service providers.

Unfortunately, once again, approaches to determining the service life of major assets vary significantly. Section 5.1.4 of CIGRE TB 422 [7] compares the results of a survey of service life from National Grid Electricity Transmission, Great Britain (NGET) and KEMA, a Dutch electricity grid research institute, as shown in Table 3-2.

Table 3-2 | Service life estimation [7]

Asset category	NGET		KEMA	
	Median	**EOSU (2,5%)/ LOSU (97,5%)**	**Mean**	**Standard deviation**
Transformers 400/275 kV 500 MVA – 750 MVA	45	30/70	50 (1,25)	7,5 (1,00)
Transformers 400/275 kV 1000 MVA	55	40/80	50 (1,25)	7,5 (1,00)
Transformer 400/132 kV GSP/GSP EE 240	55	40/80	50 (1,25)	7,5 (1,00)
Transformer 400/132 kV GSP FER 240	50	35/75	50 (1,25)	7,5 (1,00)
Transformers 275 kV	55	40/80	52,5 (1,25)	10 (1,00)
Transformers 132 kV	55	40/80	55 (1,25)	10 (1,00)
Shunt reactors	45	25/60	45 (1,25)	7,5 (1,00)
Series reactors	55	40/80	55 (1,25)	7,5 (1,00)
Capacitor bank	30	20/40	35 (1,25)	7,5 (1,00)
Static var camp	30	15/40	25 (1,25)	5 (1,00)
Switchgear 400 kV GIS outd	40	25/60	35 (1,25)	5 (1,00)
Switchgear 400 kV GIS ind	50	40/60	45 (1,25)	7,5 (1,00)
Switchgear 400 kV SF6	50	40/60	47,5 (1,25)	7,5 (1,00)
Switchgear 400 kV PAB R	50	45/60	47,5 (1,25)	7,5 (1,00)
Switchgear 400 kV PAB N	40	35/45	47,5 (1,25)	7,5 (1,00)
Switchgear 275 kV bulk oil	45	40/50	47,5 (1,25)	7,5 (1,00)

As can be seen, and matching the results from CIGRE TB 176 [2], in general, equipment was expected to have a service life of several decades, yet there is no common approach to calculating the remaining service life of a piece of equipment.

One of the state-of-the-art approaches to estimating the remaining service life of a particular piece of equipment is to use statistical methods that examine historical performance data and then look forward to future service life. Section 5.1.3 of CIGRE TB 422 [7] gives a good example of how difficult such methods are to apply. As can be seen from Figure 3-3, it can be very difficult to estimate failure probability from historical data.

Given these results, CIGRE TB 422 [7] recommends a variety of approaches when trying to predict future life, or probability of failure, from historical data. Again, this leaves open a significant risk of electricity network businesses using different approaches or inappropriate statistical methods when trying to model future service life. For example, CIGRE TB 597 [8] plots various reports on the predicted failure rate of transformers from electricity network businesses around the world. A variety of statistical methods were used to predict service life in CIGRE TB 597 [8], with each of the companies listed taking its own approach. The variations, as exemplified in Figure 3-4, make things very challenging for asset stakeholders, with the result that it is difficult to compare across types of equipment, business and maintenance approaches, and even deployment environments.

Here again, standards can improve this variability in asset life estimation. For example, a standardized set of functions to which to fit historical data could be specified, together with a method for determining which particular function to use for a given data set, considering environment and load conditions. This would dramatically improve the accuracy of service life estimation across businesses and allow benchmarking and comparison of various approaches.

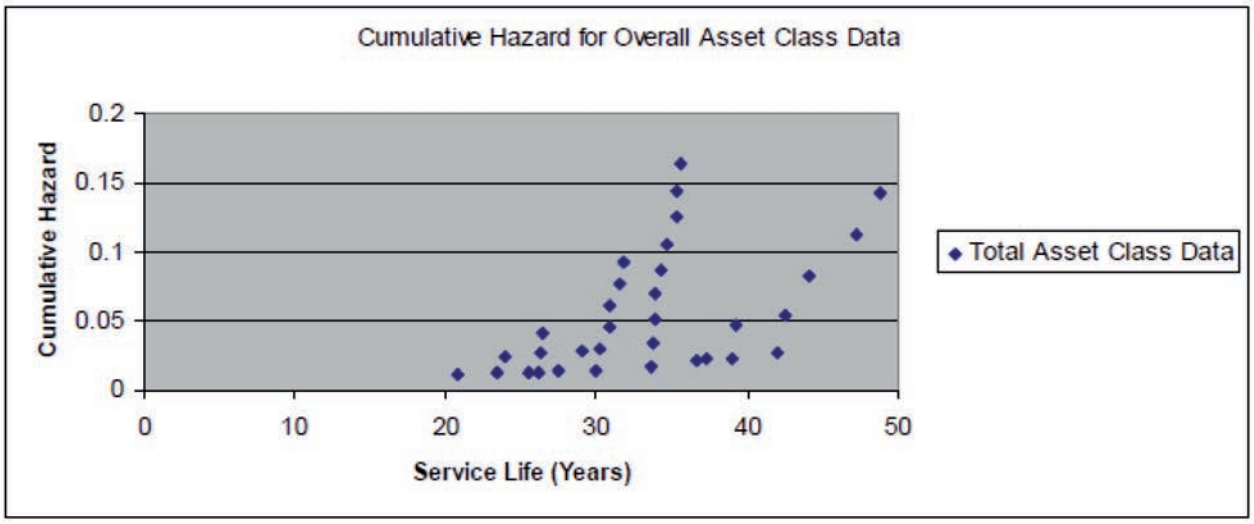

Figure 3-3 | Hazard age distribution (consolidated) [7]

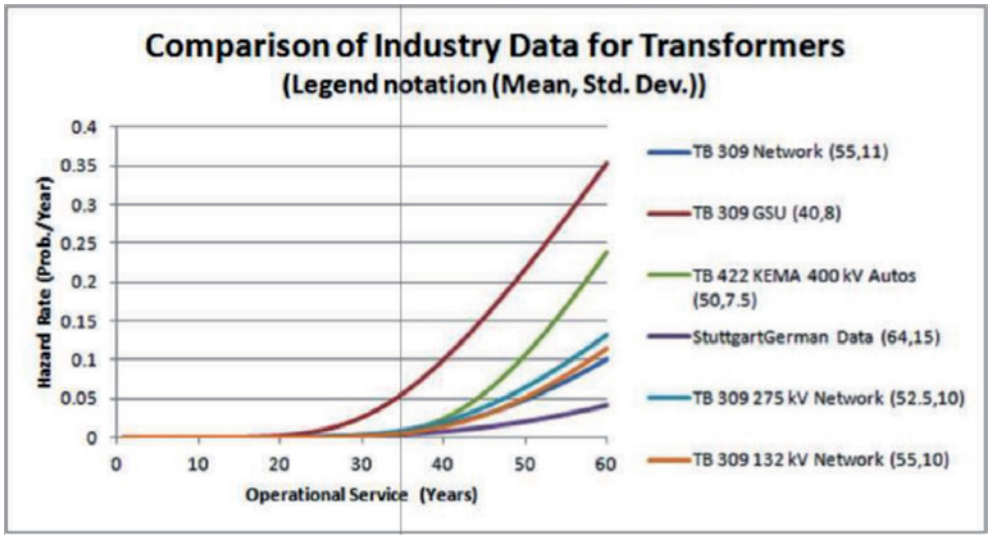

Figure 3-4 | Various hazard rates vs. age for transformers [8]

3.2.2 Formulation of countermeasures

When a fault or asset maintenance issue is identified, the next step is to determine the countermeasures that will be applied to manage the situation. Possible countermeasures could include:

- Addition of equipment
- Improvement/expansion of equipment
- Updating (replacement) of equipment
- Partial replacement, refurbishing or repair of equipment
- Change/addition of an operating method
- Change/addition of a maintenance procedure
- Provision of spare parts
- Nothing (accept the risk)

Again, there is quite significant variation in how electricity network businesses around the world choose between and apply these various countermeasures. International standards can play a role here in identifying a set of common responses to particular asset management or maintenance issues, or even helping to trace the root cause of the issue, thereby simplifying the choices a network business faces, and helping justify a particular management decision. When a regular fault has been identified by looking up that issue in a relevant standard, a network business could determine the best-practice responses to such a fault. For example, many faults occur at cable connections. When this issue was investigated by European electricity network businesses, it was found that there were 2 general causes for these faults, each with its own best-practice response. It was decided that cables affected by one type of cause should be replaced, while those suffering the other type of cause could continue to be operated, though only at low temperatures, thus avoiding the need for replacement.

As another example of where international standards associated with asset maintenance may be beneficial, consider the situation in which a major piece of equipment is faulty and the manufacturer insists on replacing the entire article, even though the fault is only occurring in a small subcomponent of the item. If the equipment owner is a relatively small or inexperienced electricity

network business, they may find it very difficult to identify alternative maintenance options and will revert to the will of the manufacture. On the other hand, if international standards were available that described this fault condition and the range of possible responses, these could be used by the network business to critically investigate their options, and substantiate their choices.

3.3 Life cycle cost and economic analysis

Having determined possible maintenance strategies and the estimated future life of a particular asset, a key next step is to determine the long-run cost of various maintenance strategies. Section 6.3 of CIGRE TB 422 [7] summarizes the principle of life cycle cost, which allows, for example, comparison of a one-time large payment immediately (for example, purchasing a replacement asset), versus smaller payments distributed over a longer period (for example, keeping an aged asset, but enforcing regular maintenance routines). In order to compare these measures, ongoing distributed expenses are converted into their present values using inflation and discount rates. In addition to the equipment cost, such analysis may attempt to include costs incurred if there is an outage and externalities such as the social license to operate.

A range of international standards already exist related to life cycle analysis and costing. Some examples include:

- ISO 14040 series concerning environmental life cycle assessment, for example, ISO 14040, *Environmental management – Life cycle assessment – Principles and framework*
- IEC 60300-3-3, *Dependability management – Part 3-3: Application guide – Life cycle costing*

Once again, significant variability exists in how life cycle costing is carried out in electricity networks. When surveyed as part of this project, some electricity network businesses indicated they do not perform life cycle costing at all, whilst for those that do, the calculation method varies significantly. For example, some electricity network businesses indicated they do not consider inflation or depreciation rates in their costing, whilst others do. Similarly, not all network businesses considered the costs of disposal in their life cycle cost calculations.

Electricity-industry specific standards on life cycle costing that build on general IEC or ISO International Standards on life cycle analysis can help here, bringing a common approach to life cycle analysis, particularly with regards to electricity network industry-specific factors such as the cost of outage, and including consideration of externalities such as community and political pressure.

3.4 Equipment and fault accident data recording

The more sophisticated electricity network businesses around the world maintain comprehensive databases of their assets, in which items are located with their equipment details. These databases can also be augmented with fault data, detailing numbers and types of faults from equipment of different manufacturers, allowing the network business to rapidly identify how many items of a particular piece of equipment are deployed and the number and type of abnormalities that have been experienced in that equipment. Some examples of failure rates for common electrical network assets are provided in Annex C.

Recording equipment and accident data can also allow for specific forms of analysis, such as understanding the type and frequency of abnormalities that occur in equipment from various vendors or equipment models and compiling proactive maintenance plans based on comprehensive historical data. Unfortunately, many electricity network businesses do not

maintain such databases, or the data they collect lacks important detail such as manufacturer or failure details. Often such databases were originally intended for other business purposes, such as financial reporting, and thus lack the ability to record the detailed technical information that could greatly assist asset management.

A centralized database of fault data could, for example, broadcast information to all users when a major fault occurs on one particular item of equipment, thereby alerting others to carefully monitor that equipment for failure symptoms. Such a database would have particularly significant benefits for smaller electricity network businesses that simply do not have a sufficient asset base for drawing statistically significant data from their own system. Some potential references that may guide activities here include Section 5.1 of CIGRE TB 422 [7] for accident data and Chapter 3 of CIGRE TB 597 [8] for related practices.

Some of the most modern asset management practices include techniques such as failure mode and effects analysis (FMEA). Such approaches examine the various modes through which an asset deteriorates and which of these modes may cause faults, and then specify which types of inspection can be used to determine the various modes of deterioration. Given the breadth of equipment and failure characteristics in a typical power network, such analysis is costly and time-consuming. International standards can play an important role in easing this burden by providing pre-prepared references for the common failure modes of common electricity network business assets, the methods to identify these and routine maintenance procedures to manage them.

International standards can also be used to provide a reference for understanding common failure rates and modes for various common items of equipment. Here again, a worldwide database of historical performance and failure information would prove an invaluable reference piece to assist in predicting likely failures for a particular asset and the impact of such failures.

Section 4

Risk analysis and prioritization

Ultimately, one of the most important and challenging tasks in asset management is the evaluation of risk and prioritization of various asset management options. When the project team surveyed electricity network businesses regarding their practices in this area, the survey results indicated that such businesses use a range of methods to analyze risk and prioritize their options. For example:

- Whilst almost all electricity network businesses consider equipment failure in their risk analysis, only approximately 15% of the respondents consider the frequency of natural disasters such as earthquakes or major storms.
- Only approximately 15% of electricity network businesses consider human action (from major procedural failures to terrorist attacks) in their risk analysis.
- Approximately 80% of electricity network businesses perform risk analysis by focusing on individual assets. Others consider the system as a whole, analysing the risks associated with a particular section of the network, and the components in it.
- Approximately 60% of respondents use a risk matrix as the key mechanism in their risk analysis. The remainder use a mixture of techniques, from quantitative methods to qualitative evaluation.

4.1 Risk analysis

As found in the survey results, the most common approach to risk management is the use of a risk matrix to analyze the implications of a particular risk. A risk matrix is generally composed of one axis expressing "impact" (sometimes also referred to as significance, criticality or severity) and another axis expressing "frequency of occurrence". Figures 4-1 to 4-3 show 3 examples of a risk matrix.

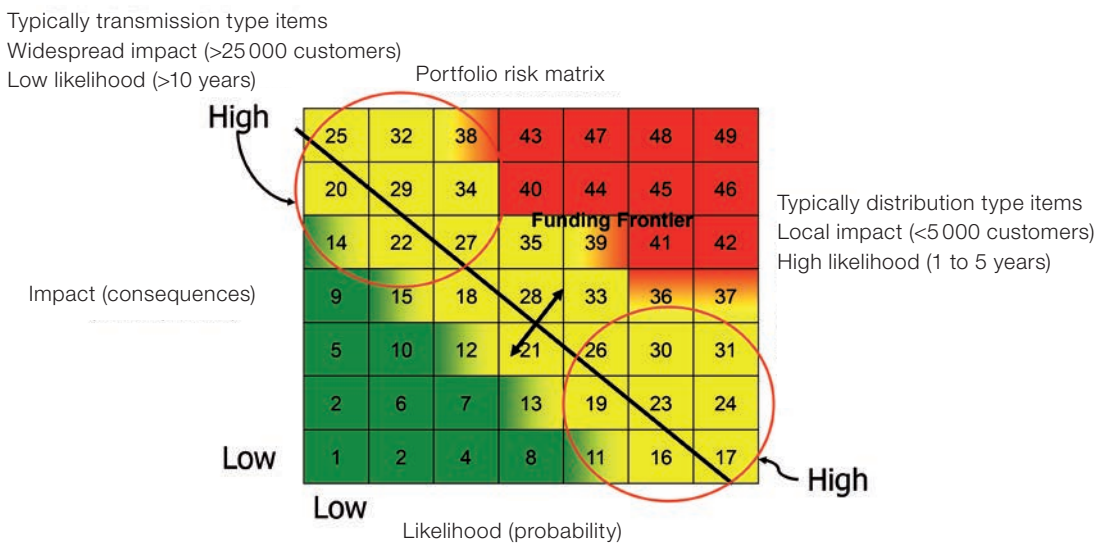

Figure 4-1 | Example of a risk matrix (ComEd 2015, from IEC MSB workshop)

LIKELIHOOD GUIDELINES	LIKELIHOOD OF OCCURRENCE						
90%	(9 in 10) or greater likelihood that event will occur within next year.	5	Moderate	Moderate	High	Extreme	Extreme
50%	(1 in 2) or greater likelihood that event will occur within next year.	4	Guarded	Moderate	High	Extreme	Extreme
10%	(1 in 10) or greater likelihood that event will occur within next year.	3	Guarded	Moderate	Moderate	High	Extreme
1%	(1 in 100) or greater likelihood that event will occur within next year.	2	Low	Guarded	Moderate	Moderate	High
<1%	<1% (1 in 100) likelihood that event will occur within next year.	1	Low	Low	Guarded	Guarded	High
IMPACT CRITERIA			1	2	3	4	5
Safety			First aid injury/illness	Medical aid injury/illness	Lost time injury/ temporary disability	Permanent disability	Fatality (ies)
Financial			Impact totaling < $500,000	Impact totaling $500,000 - $1 Million	Impact totaling $1 Million - $5 Million	Impact totaling $5 Million - $10 Million	Impact totaling ≥ $10 Million
Reliability			One of: < 250,000 customers hrs lost or < 2 GWh of energy not served or delivered.	One of: 250,000 – 1 million customers hrs lost or 2 -7 GWh of energy not served or delivered.	One of: 1 - 3 Million customer hrs lost or 7 - 20 GWh of energy not served or delivered.	One of: 3 Million - 7 Million customer hrs lost or 20 - 50 GWh of energy not served or delivered.	One of: ≥ 7 Million customer hrs lost or ≥ 50 GWh of energy not served or delivered.
Market Efficiency			Customers and rate payers lodge complaints to BCTC	BCTC customers and rate payers lodge complaint to Government or the Utilities commission	Government or BCUC enquiry conducted into BCTC practices and policies	Government or BCUC impose strategic and operational changes upon BCTC	Failure to deliver required level of service resulting in loss of license to operate
Relationships			External opposition resulting in short term delays or minor modifications to work plans.	External opposition affecting BCTC's ability to implement its work plans is constrained and/or substantive modifications of its work plans are required.	External opposition resulting in increased regulatory oversight; shareholder scrutiny and/or restricted access to work sites.	External opposition resulting in increased regulatory/ legislative/court action or government intervention resulting in a loss of responsibilities impacting BCTC's corporate mandate, including restricted access to major project sites.	External opposition resulting in loss of license to operate and/or imposed corporate restructing
Organization & People			Negligible impact on service delivery and staff.	Impacts the efficiency or effectiveness of some services, but would be dealt with internally.	Portions of the organization experience unexpected attrition or reduced attraction factors.	The ability to achieve the corporate goals is threatened or there is a significant increase in the cost of service.	Unexpected loss of multiple critical staff including senior leadership and the ability to deliver critical services.
Environment			Non-reportable environmental incident	Reportable environmental incident with short term mitigation (<1year)	Reportable environmental incident with long term mitigation (> 1year)	Reportable environmental incident with regulatory fines and mitigation possible.	Reportable environmental incident with regulatory prosecution and/or uncertain mitigation.

Severity Classification	
Extreme	Must be managed through a detailed plan by an Executive.
High	Detailed research and planning required at senior management; Executive attention is required.
Moderate	Management responsibility must be specified; Manage by specific monitoring or response procedures.
Guarded	Managed by routine procedures - regular monitoring required.
Low	Managed by routine procedures.

Figure 4-2 | Example of risk matrix (BCTC in Canada, 5x5) [13]

Risk matrix

			Impact						
			Catastrophic	Serious	Considerable	Mediocre	Small	Very small	Minor
Strategic objectives	Safety		Multiple casualties	One casualty	Serious injury	Injury with absenteeism	Injury without absenteeism	Minor injury with first aid	Minor injury without first aid
	Quality of supply		See table	See table	See table	See table	See table	See table	See table
	Financial		> 100.000 k€	10.000 k€ - 100.000 k€	1000 k€ - 10.000 k€	100 k€ - 1000 k€	10 k€ - 100 k€	1 k€ - 10 k€	< 1 k€
	Reputation	Attention	National / Politics	National / Regional / In sector	National / Politics	National / Regional / In sector	National	Regional / In sector / Local	Local
		Cause	Intentionally / Fraud	Intentionally / Fraud	Unintentional	Unintentional	Force majeur	Force majeur	Unintentional
	Environment		Criminal law sanction	Law suit	Administratrative fine	Disturbance over more than 500 metres	Effect > 125% of associated code / disturbance within 500 metres	Effect in between 100% and 125% of associated code / disturbance within 50 metres	Disturbance within fence
	Compliance		Criminal law sanction	Law suit	Administratrative fine	Indemnification	Non-conformity / warning	Grouped and honoured complaint	Honoured complaint
Failure frequency	Very often	More than 10 times a year	Unacceptable	Unacceptable	Unacceptable	Very high	High	Medium	Low
	Often	More than once a year	Unacceptable	Unacceptable	Very high	High	Medium	Low	Negligible
	Regular	Once every 1 - 10 years	Unacceptable	Very high	High	Medium	Low	Negligible	Negligible
	Probable	Once every 10 - 100 years	Very high	High	Medium	Low	Negligible	Negligible	Negligible
	Possible	Once every 100 - 1,000 years	High	Medium	Low	Negligible	Negligible	Negligible	Negligible
	Improbable	Once every 1,000 - 10,000 years	Medium	Low	Negligible	Negligible	Negligible	Negligible	Negligible
	Nearly impossible	Less than once ever 10,000 years	Low	Negligible	Negligible	Negligible	Negligible	Negligible	Negligible

Quality of supply		Duration					
		< 2 hours	2 - 6 hours	6 - 12 hours	12 - 24 hours	24 hours - 1 week	> week
Outage	< 100 MW	Very small	Small	Mediocre	Considerable	Serious	Catastrophic
	< 250 MW	Small	Mediocre	Considerable	Serious	Serious	Catastrophic
	< 500 MW	Mediocre	Considerable	Considerable	Serious	Catastrophic	Catastrophic
	< 1000 MW	Considerable	Considerable	Serious	Catastrophic	Catastrophic	Catastrophic
	< 1500 MW	Serious	Serious	Catastrophic	Catastrophic	Catastrophic	Catastrophic
	> 1500 MW	Serious	Catastrophic	Catastrophic	Catastrophic	Catastrophic	Catastrophic

Figure 4-3 | Example of risk matrix (Netherlands, 7x7, Section 4.2 of CIGRE TB 541 [9])

Section 6.2.3 of CIGRE TB 422 [7] introduces an example of the registration of a risk in a network business's database in the Netherlands. By registering the risk using this matrix format, the asset manager and the service provider can communicate with each other using a common language and understanding of the impacts of the risk. For more information refer to Section 4.2, Annex B of CIGRE TB 541 [9].

4.1.1 Risk matrix (evaluation of impact)

The impact axis in a risk matrix is usually not a single measurement, but rather includes a range of items such as:

- Impact on human safety
- Economic impact
- Impact on reliability
- Impact on the environment

Severity ↑	Per incident	Safety	Financial	Reliability	Environment
	Impact class 5	Fatality(ies)	Impact totalling ≥ USD 10 million	Customer hours lost ≥7 million	Reportable environmental incident with regulatory prosecution and/or uncertain mitigation
	Impact class 4	Permanent disability	Impact totalling USD 5 to 10 million	Customer hours lost 3 to 7 million	Reportable environmental incident with regulatory fines and mitigation possible
	Impact class 3	Lost time injury/ temporary disability	Impact totalling USD 1 to 5 million	Customer hours lost 1 to 3 million	Reportable environmental incident with long term mitigation (>1 year)
	Impact class 2	Medical aid injury/ illness	Impact totalling USD 0,5 to 1 million	Customer hours lost 0,25 to 1 million	Reportable environmental incident with short term mitigation (<1 year)
	Impact class 1	First aid injury/ illness	Impact totalling < USD 0,5 million	Customer hours lost <0,25 million	Non-reportable environmental incident

Figure 4-4 | An example of various risk analysis impacts (Section 4.3 of CIGRE TB 422 [7])

		Catastrophic	Serious	Considerable	Mediocre	Small	Very small	Minor
Safety		Multiple casualties	One casualty	Serious injury	Injury with absenteeism	Injury without absenteeism	Minor injury with first aid	Minor injury without first aid
Quality of supply		See table	See table	See table	See table	See table	See table	See table
Financial		> EUR 100 000K	EUR 10 000K – 100 000K	EUR 1 000K – 10 000K	EUR 100K – 1 000K	EUR 10K – 100K	EUR 1K – 10K	< EUR 1K
Reputation	Attention	National/ Politics	National/ Regional/ In sector	National/ Politics	National/ Regional/ In sector	National	Regional/ In sector/ Local	Local
	Cause	Intentionally/ Fraud	Intentionally/ Fraud	Unintentional	Unintentional	Force majeur	Force majeur	Uninten-tional
Environment		Criminal law sanction	Lawsuit	Administrative fine	Disturbance over more than 500 metres	Effect >125% of associated code/distur-bance within 500 metres	Effect in between 100% and 125% of associated code/distur-bance within 50 metres	Disturbance within fence
Compliance		Criminal law sanction	Lawsuit	Administrative fine	Indemnifica-tion	Non-conformity/ warning	Grouped and honoured complaint	Honoured complaint

Figure 4-5 | An example of the impact axis (Section 4.2 of CIGRE TB 541 [9])

These items are often evaluated depending on the severity of the impact, as shown in Figures 4-4 and 4-5. In the Netherlands example, impacts evaluated also included:

- Reputation of the company
- Compliance

CIGRE TB 541 [9] includes an example of the evaluation of the impact on the environment. It clearly shows that such analysis should consider:

- Energy usage
- Overhead power transmission
- Waste
- SF_6 leakage
- CO_2 emission
- Oil leakage

Even more detail is considered in CIGRE TB 383 [14], as shown in Table 4-1.

Importantly, the consideration of these risks changes over time. Some risks may not have been regarded as problematic historically, but in more modern times are considered a significant issue. Examples here would include:

- Oil leakage from an oil-filled cable laid beneath the road surface
- Induced voltages on communication lines by short-circuit/ground-fault currents
- The range of approaches to worker safety
- Public acceptance of overhead lines

Whilst the use of risk matrices is fairly widespread, their application varies significantly. For example, there may be a lack of detail regarding definitions of acceptable impacts, or a network business may not consider all potential impacts of a risk. Alternatively, in poor implementations the evaluation of risk is done by intuition rather than using verifiable metrics, and different evaluations may give different results for the same risk.

Table 4-1 | Example of environmental impact items [14]

Aspect: Energy		
EN3	Direct energy consumption by primary energy source	Section 3.1.1
EN4	Indirect energy consumption by primary energy source	Section 3.1.1
Aspect: Biodiversity		
EN11	Location and size of land owned, leased, managed in, or adjacent to, protected areas and areas of high biodiversity value outside protected areas	Section 3.1.3
EN12	Description of significant impacts of activities, products and services on biodiversity in protected areas and areas of high biodiversity value outside protected areas	Section 3.1.3
EU14	Biodiversity of replacement habitats compared to the biodiversity of the areas that are being replaced	Section 3.1.3
Aspect: Emissions, effluents and waste		
EN16	Total direct and indirect greenhouse gas emissions by weight	Section 3.1.2
EN22	Total weight of waste by type and disposal method	Section 3.1.4
EN23	Total number and volume of significants spills	Section 3.1.5
Aspect: Compliance		
EN28	Monetary value of significant fines and total number of non-monetary sanctions for non-compliance with environmental laws and regulations	
EN30	Total environmental protection expenditures and investments by type	

Given the variety of risk matrices and their application, it would seem difficult for standards to prescribe a risk matrix in a globally unified manner. However, standards could still bring significant benefit to practices here – for example, by ensuring a minimum set of impacts that should be included in any risk evaluation. Again, standards might specify 3 categories of risk management (and the matrices for each category) – for example, a minimal set of evaluation, an optional set and a best-practice set.

For instance, inductive interference may be determined as an essential item for evaluation of risk for an underground cable, while oil leakage is considered optional by some jurisdictions.

Specifying metrics for particular impact may also prove to be problematic in a standards framework. For example, some businesses may consider a financial loss of USD 10 000 as a significant impact, whereas others may consider this amount inconsequential. Whilst standards may not be able to specify how to interpret various metrics, they can certainly specify the metric itself – for example, by standardizing that economic impact be measured in terms of a particular currency unit, or that human safety be measured in terms of lost time injuries or fatalities.

By standardizing as much as possible the way to measure the impact of particular risks, communications across stakeholders is rendered much easier, thereby dramatically improving risk management within the electricity network business.

4.1.2 Risk matrix (frequency analysis)

Just as in the case of impact analysis, a variety of factors are used when considering the likely frequency of an event. Typically, frequency is defined either as "once per a specified number of years" or as "the probability of occurring within the next year", as the case may be. Some of these matrices also consider very rare incidents – for example, less than once in 10 000 years as shown in the right side of Figure 4-6.

As with impact analysis, what is considered an acceptable level of frequency for a particular failure varies dramatically across businesses, and it would be inappropriate for standards to specify this. However, standards could specify a range of categories, ranging from minimum (a relatively high number of occurrences) to best practice (a relatively low number of occurrences).

Probability of occurrence

≥90% likelihood that event will occur within next year
≥50% likelihood that event will occur within next year
≥10% likelihood that event will occur within next year
≥1% likelihood that event will occur within next year
<1% likelihood that event will occur within next year

Very often	More than 10 times a year
Often	More than once a year
Regular	Once every 1-10 years
Probable	Once every 10-100 years
Possible	Once every 100-1 000 years
Improbable	Once every 1 000-10 000 years
Nearly impossible	Less than once every 10 000 years

Figure 4-6 | Examples of the frequency axis of a risk matrix (Canada (left) [13] and Netherlands (right) [7])

4.2 Health index

When considering the range of equipment in various stages of health or operational readiness, a key challenge for an asset manager is to prioritize the various countermeasures available with regard to the equipment needing attention. In addition to the use of risk matrices, a promising approach to this challenge is to use a health index. Figure 4-7 shows an example of calculating a health index for a power transformer. In a health index, multiple parameters such as equipment status, usage, age and deterioration rate are weighted, and a health score for each equipment item is then calculated. Section 5.4 of CIGRE TB 422 [7] describes health indices in detail.

Given the diversity of possible approaches to calculating a health index, it would be difficult to specify one single approach in an international standard. However, such a standard could give a number of examples of best-practice health index calculation, which could then be used as reference pieces for the broader industry. Annex D describes examples of parameters that could be used in calculating health index.

4.3 Network analysis

Power transmission equipment is assembled in a network, often with parallel paths and redundancy built in. Given this structural complexity, efficient

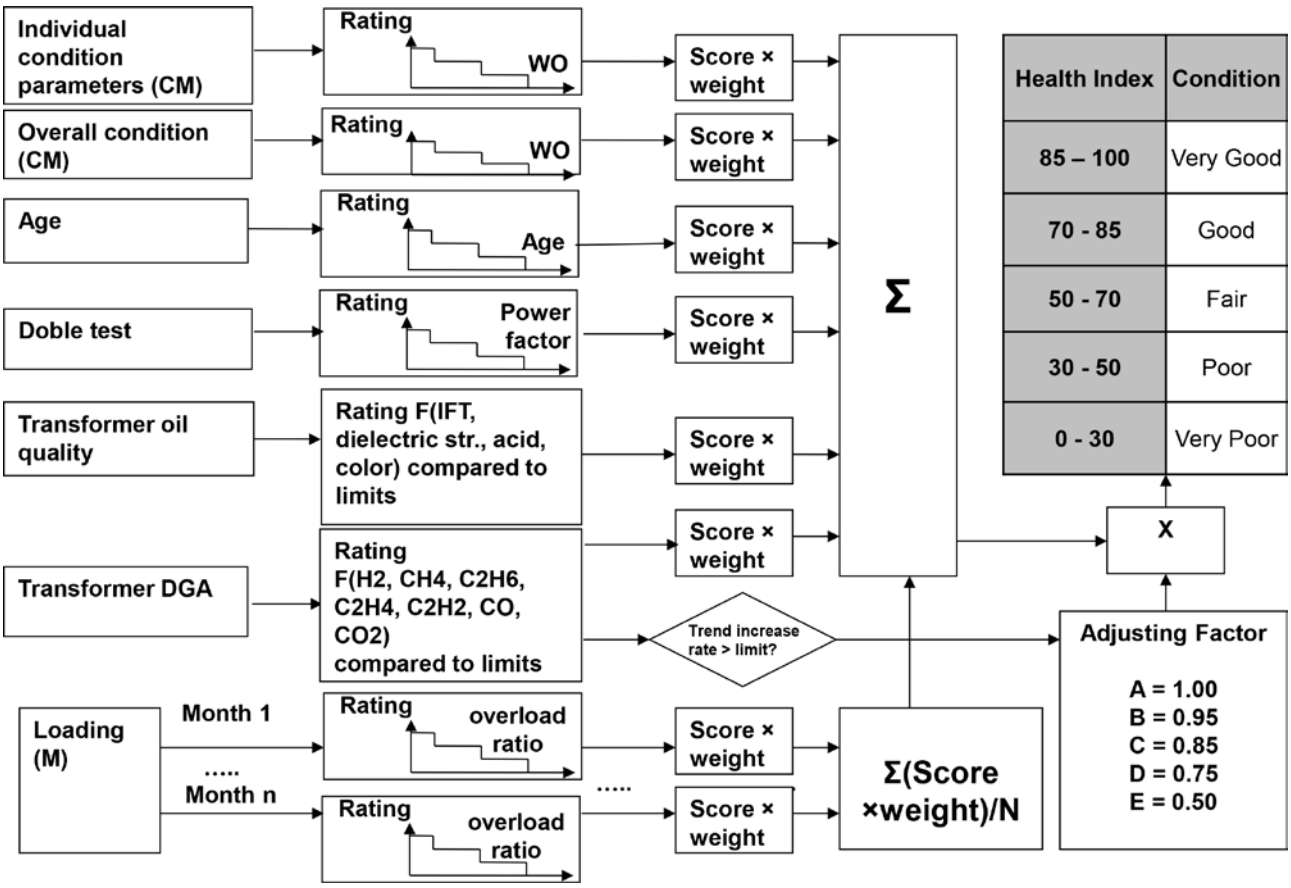

Figure 4-7 | Example of a health index (ComEd 2015, from IEC MSB workshop)

asset management practices should consider the electricity network as a whole. For example, when one particular asset needs maintenance or replacement, the network business may also consider working on adjacent assets, even though these may not yet be due for maintenance. By conducting several projects at the same network locations simultaneously, the number of planned outages can be reduced, thus enhancing network reliability during replacement works. The planning of such combined efforts generally involves projecting nearby facilities and their current state onto one map layer, as shown in Figure 4-8, from which asset managers can change the priorities and/or timing of replacement of particular facilities to reduce planned outages.

Consideration of multiple adjacent assets, and scheduling work based on reducing later planned outages, are practices that are not always implemented in electricity network businesses, often leading assets to be considered only in isolation, which results in unnecessary planned outages and inefficient maintenance practices. Standards could assist here by suggesting asset management techniques that consider the power system as a whole, thereby improving efficiency and reducing planned outages.

4.4 Prioritization

Having performed an analysis of the risks associated with various actions (or inaction), and having evaluated the relative health of pieces of equipment across the network, the asset manager must then try to prioritize the appropriate actions. Various factors need to be taken into account in order to prioritize among multiple projects. Responses to the project team's survey of electricity network businesses indicated a range of approaches to prioritization:

- Approximately two-thirds of network businesses prioritize projects in a fixed order: those considered mandatory, followed by capital projects and then general operation and maintenance projects. The remainder of electricity network businesses prioritize based on risk evaluation and the timeliness of response.
- Whilst all network businesses consider projects driven by regulatory requirements to be mandatory, only approximately 33% consider projects driven by demand growth to be mandatory.
- Whilst most network businesses consider dealing with demand growth, aging infrastructure or capacity upgrades as key drivers for major capital projects, only

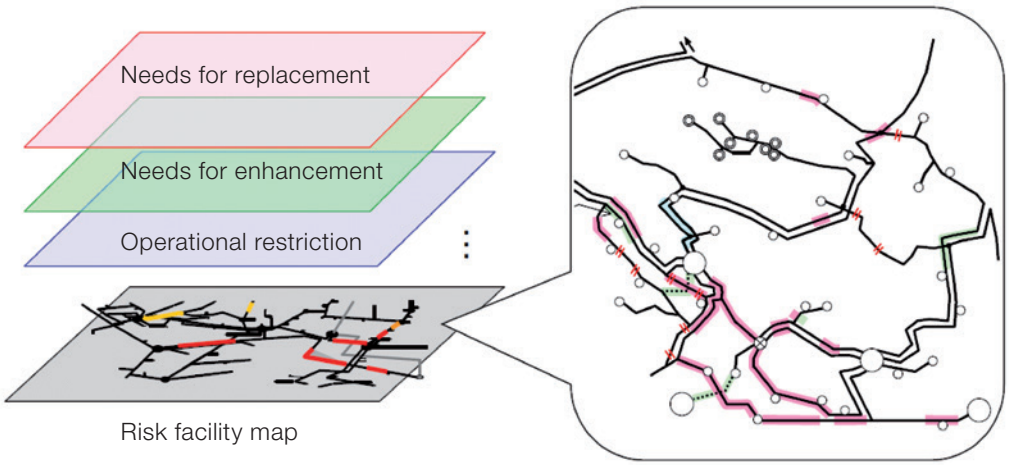

Figure 4-8 | Map of various facilities and their risk impacts/requirements

approximately 25% consider safety issues a key driver for such projects.

- A small majority of network businesses use risk analysis to prioritize between capital and operations and maintenance projects. Some other businesses calculate expected financial returns for such prioritization, whilst others consider capital projects as mandatory, followed by operations and maintenance.
- When analyzing how critical a particular asset is, almost all electricity network businesses consider the amount of energy or power flowing through the equipment and the loads that are connected to it (i.e. whether any of these loads are critical, such as hospitals). Only 50% of network businesses consider the characteristics of the broader network to which the asset is connected (whether it is a residential or industrial area, etc.).

4.4.1 Prioritization using a health index

Considering the range of possible prioritization methods, one approach is to prioritize based on health index results. Chapter 4, Annex C of CIGRE TB 541 [9] describes the case of a Canadian network business prioritizing among various countermeasures by using a health index, where the health index is a number based on analyzing age, historical failure and impact of failure data, to determine what equipment is most likely to fail *and* when such a failure may have a significant impact.

4.4.2 Prioritization using a risk matrix

Alternatively, a risk matrix alone might be used to prioritize amongst projects. Section 5.2 of CIGRE TB 541 [9], introduces the case of a Netherlands network business performing prioritization among multiple projects using a risk matrix. In this case, the business assessed the risk impact of each project (preferably by economic analysis, otherwise by a qualitative analysis and subsequent numerical score) and the occurrence probability, weighting the resulting value to give a final ranking score.

4.4.3 Prioritization using a risk scoring

Commonwealth Edison of Chicago approach prioritization using a risk scoring. As presented at the IEC MSB workshop in Washington DC, Commonwealth Edison scores as follows.

Every project or programme that requests funding is risk scored in terms of:

- Safety
- Environmental impact
- Reliability

1) After performing the risk assessment a range of items to be funded to improve the system is identified. For example, 10% of the available funding may be used to replace all high risk assets, as shown in Figure 4-9.
2) By targeting funding of the items with the highest risk, Commonwealth Edison is able to maximize the impact of its infrastructure investments in the transmission and distribution system, while continuing to improve overall reliability.
3) The model also enables the company to look ahead at which items will need to be replaced in the upcoming years.

4.4.4 Prioritization and standards

Whilst the 3 examples above give a sense of how electricity network businesses approach the prioritization of various asset management choices, many alternative approaches exist. Again, given the lack of maturity of the work in this area, and the diversity of approach, it would seem inappropriate to attempt to specify one particular prioritization approach in an international standard. Nonetheless, prioritization

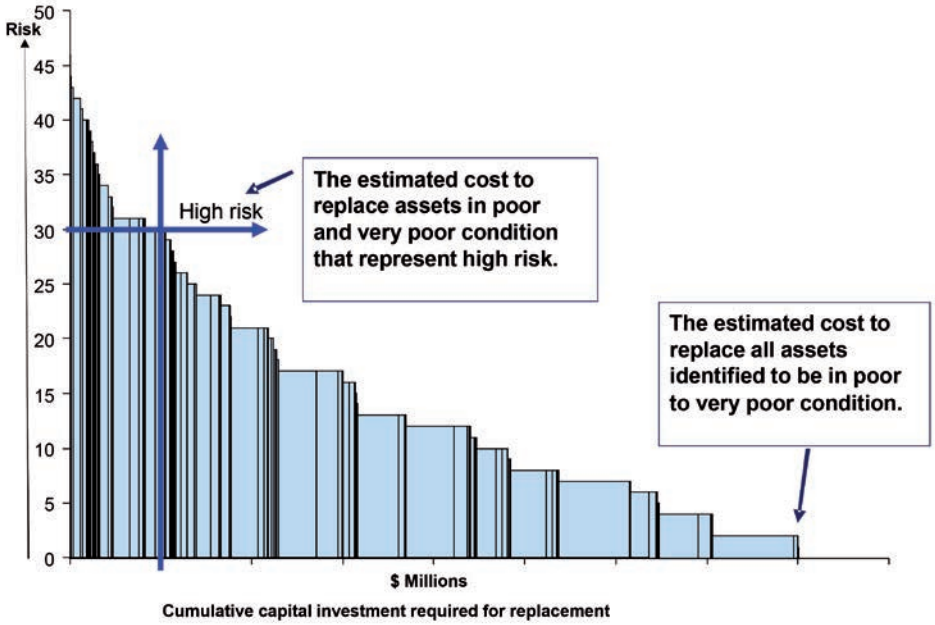

Figure 4-9 | Long term planning and prioritization (ComEd 2015, from IEC MSB workshop)

of various countermeasures is a critical task for an electricity network business, and it is likely to lead to the facilitation of communication between an electricity network business and its stakeholders, if best practice is introduced and standardized approaches can be referenced. In this case, the role of standards might be to provide detailed case studies of best-practice approaches, which electricity network businesses can then use as reference pieces for their own work.

4.5 Mid- to long-term strategies and other analyses

Another factor in asset management decision-making is to try and maintain a stable investment/expenditure environment. For example, Section 4.1.3.3 of CIGRE TB 541 [9] presents the case of a Canadian network business considering several years of asset management projects. If the network business were to prepare their asset management plan using only a health index, as described in the previous sub-sections, the amount of work to be done would differ considerably in each fiscal year, with very significant peaks and troughs, as shown in Figure 4-10.

By levelling the workload across several years, the increase in temporary risks in terms of economy, safety and environment of such a peaky workload could be avoided and the above plan could be made more useful for all the stakeholders, as shown in Figure 4-11.

Section 6.4 of CIGRE TB 422 [7] summarizes the formulation of mid-/long-term asset management strategies, with the aim of levelling across years. In this reference, a long-term stable strategy is formulated by going through each of the following steps:

1) Evaluation of the current status of each equipment item
2) Creation of a deterioration model for each equipment item
3) Simulation of various asset management measures, considering restrictions such as availability of staff or budget

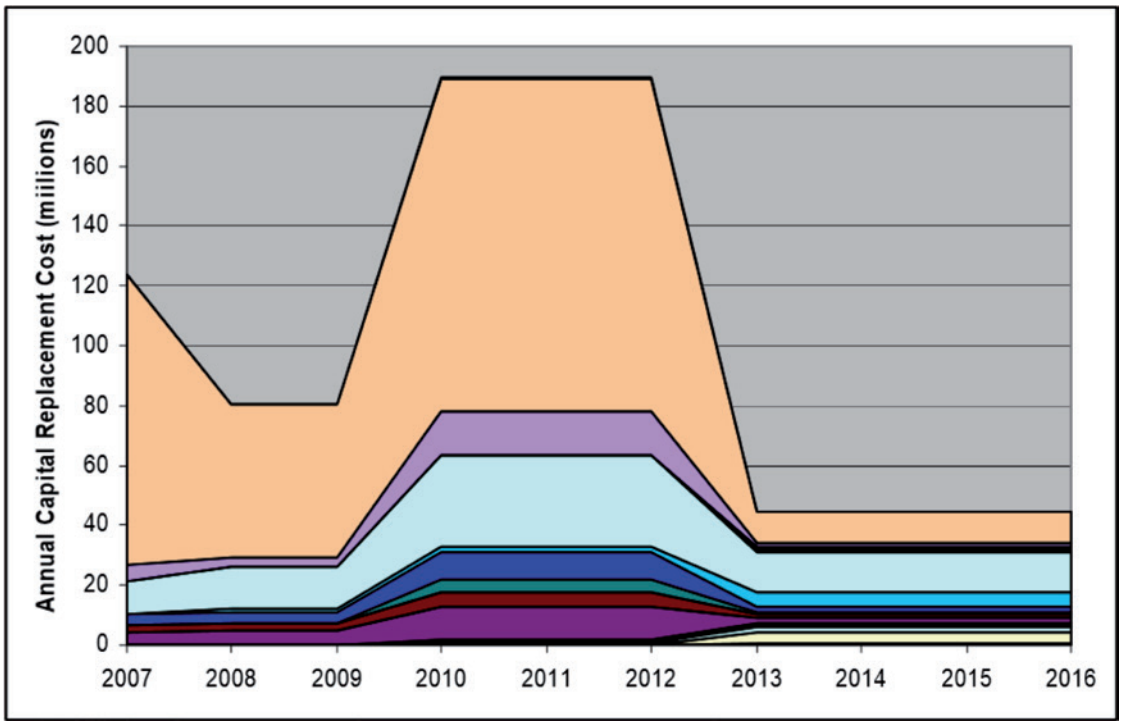

Figure 4-10 | Replacement plan without levelizing [9]

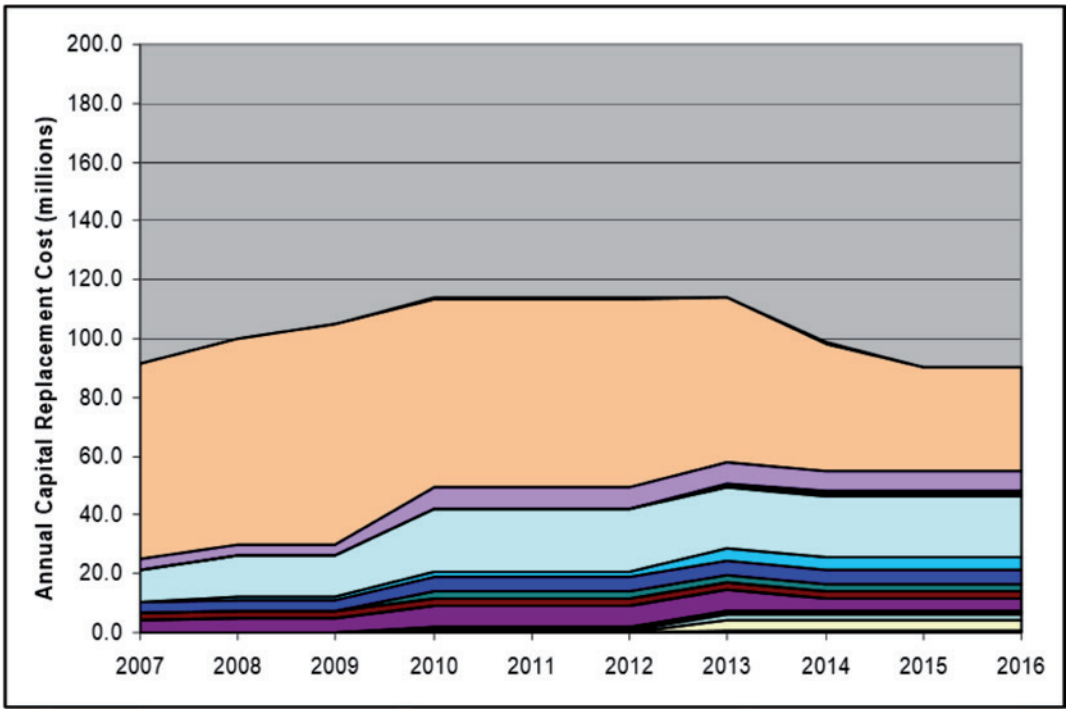

Figure 4-11 | Levelized replacement plan [9]

4) Evaluation of the impact on the staff, customers and long term finances (as shown in Figure 4-12)

5) Analysis of the simulation result and subsequent decision-making

Broader considerations here might also include stakeholders outside the electricity network business itself. For example, a significant constraint on any planning might include equipment vendors and the availability or their materials or workforce.

Ultimately, it is clear that any preparation of asset management plans should take a long-term view and should strive to manage a range of constraints, from availability of personnel to budgets and customer impacts. International standards can play a role in guiding electricity network businesses and other stakeholders on the best-practice methods for such planning. CIGRE TB 422 [7] provides a number of case studies and example methods in this area, which are good examples of potential standard material.

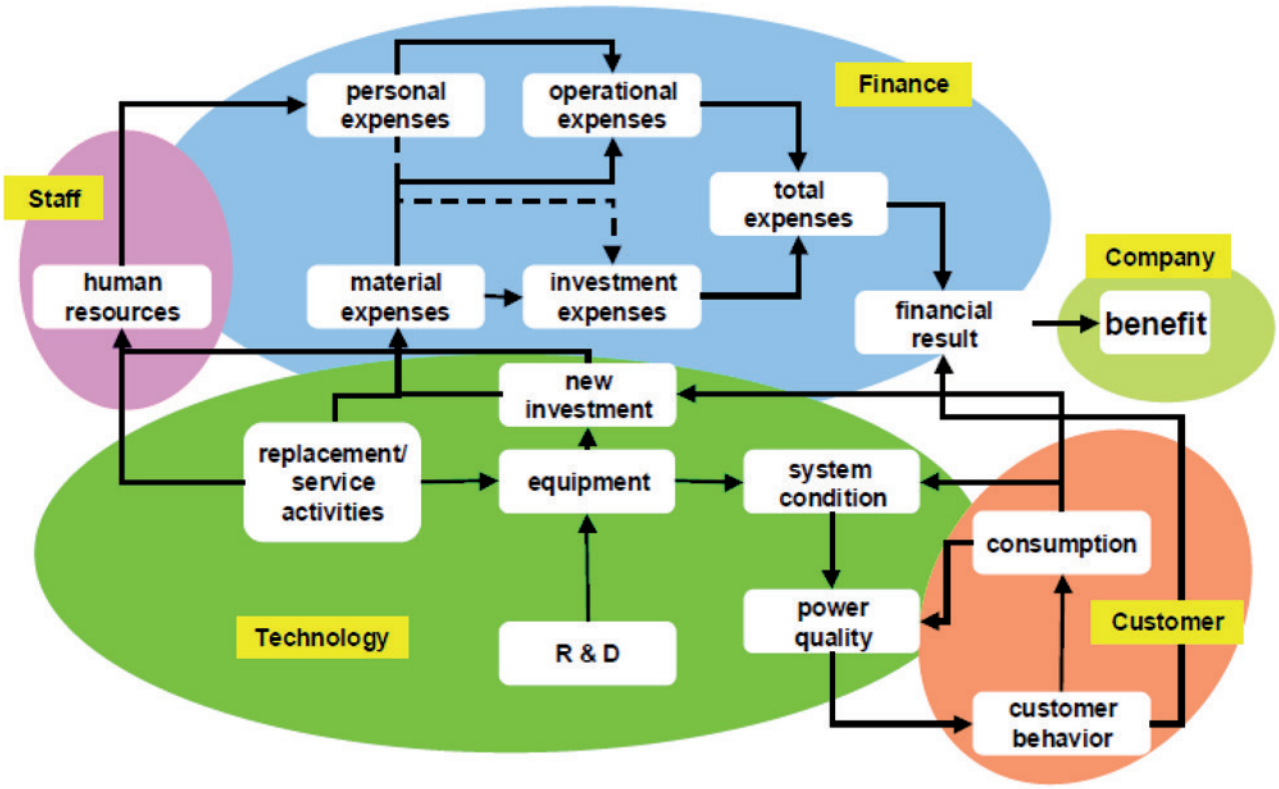

Figure 4-12 | Overall asset management strategy [7]

Section 5

Asset owner decisions

Whilst much of the focus of asset management is on short-term issues – how to manage maintenance and upgrades across the network – asset owners need to have a longer-term view, aiming to make investment decisions that ensure the long-term success of the business, and balancing these against short-term asset management commitments and constraints.

Chapter 4 of CIGRE TB 422 [7] gives an overview of the typical decisions of an asset owner. This commonly includes trying to balance business returns against regulatory requirements, making strategic investment decisions amid industry and technology changes, etc. Given the long-term nature of such an analysis, the metrics and evaluation criteria used by asset owners are critically important.

5.1 Reliability indicators

One of the key metrics in understanding the longer-term impacts of a decision is how it affects the electricity network's reliability. There are a variety of indicators associated with reliability, including:

- Interruption performance measures, such as system/customer minutes lost, system average interruption duration index (SAIDI), system average interruption frequency index (SAIFI), number of major events, number of supply interruption events, number of events with loss of supply, unsupplied energy per total number of delivery points, etc.
- Availability/unavailability measures (for example, annual average availability, transmission continuity)
- Power quality performance measures (for example, voltage magnitude/regulation, voltage unbalance, regulated voltage ratio, total harmonic distortion)
- Disturbance measures (for example, number of line faults/incidents/outages)

Sections 1.3 and 2.4 of CIGRE TB 367 [15] give further detail on various industry indicators of reliability from around the world. These indicators are often used in regulatory processes to give incentives or penalties to transmission or distribution operators based on their system performance, and to provide benchmarking across organizations. Performance can vary significantly across different operators. For example, Figure 5-1 shows the SAIDI data for European countries, where the interruption duration can range from less than 20 min to over 500 min [16].

Whilst metrics such as SAIDI, SAIFI and unsupplied energy are commonly used by electricity network businesses to examine the performance of their own business and compare this to that of other businesses, there are significant problems with this approach. Unfortunately the definition for these commonly used indicators varies across organizations and regulatory jurisdictions. For example, on one hand, the definition for SAIDI in transmission, "T-SAIDI", is

$$\text{T-SAIDI} = \sum \text{customer interruption duration/total number of delivery points monitored}$$

on the other hand, the definition for SAIDI in distribution is

$$\text{SAIDI} = \sum \text{customer interruption duration/total number of customers served}$$

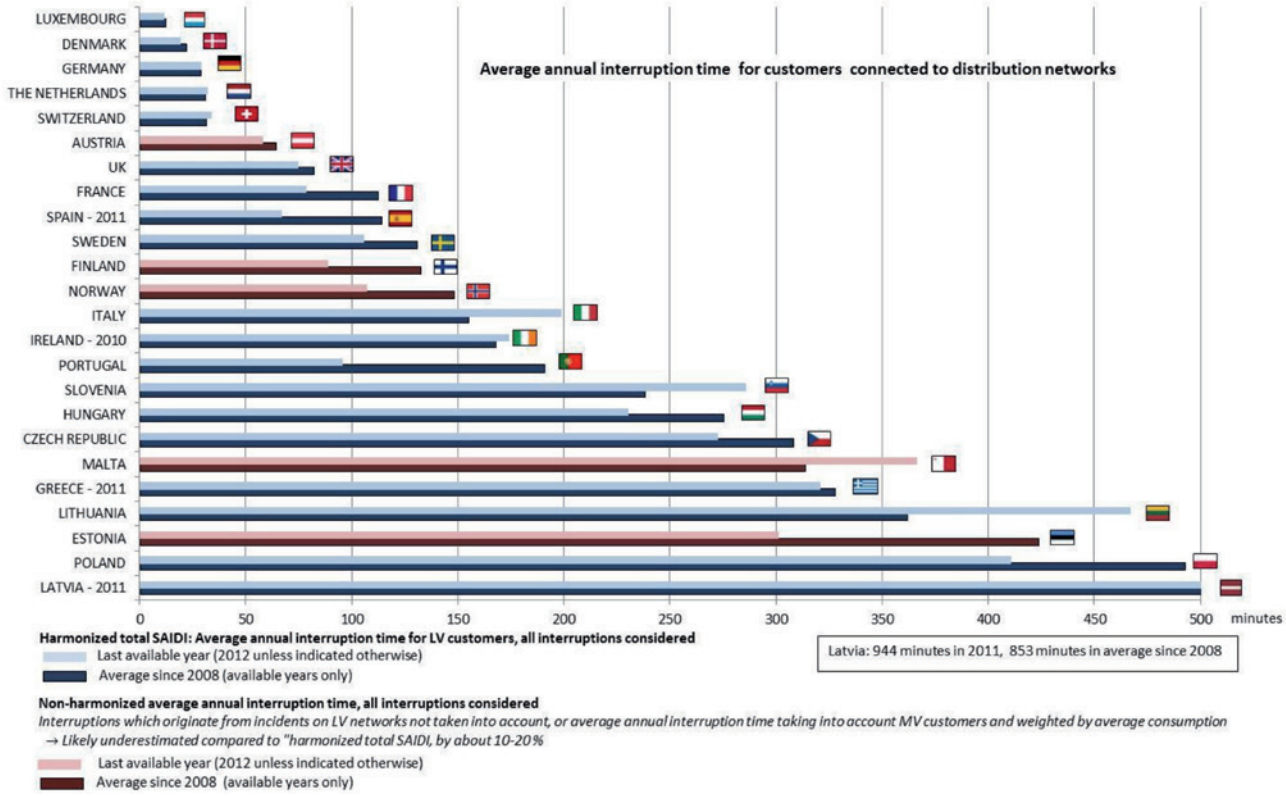

Figure 5-1 | SAIDI data for Europe [15]

In addition, the definitions for SAIDI and SAIFI vary subtly across European countries. The differences include:

- Blackouts lasting for a short time may not be included.
- Scheduled power interruptions (outage) may not be included.
- Large-scale disasters are often not included.

The definitions are described in a CEER report [17] for each country.

The variation in how common industry performance metrics are defined is hardly ideal, and makes it difficult to compare the performance of different transmission and distribution systems accurately. International standards have a key role to play in removing this variability. In the US, IEEE 1366 [18] defines metrics such as SAIDI and SAIFI. This standard has been adopted in some parts of Asia and thus may serve as a useful guideline in the preparation of more international standards in this area.

In addition to metrics already suggested in various industry documents (such as those cited above), the following metrics were commonly cited by electricity network businesses from around the world surveyed by the project team regarding what reliability metrics they use in relation to bulk power systems transmission-related events:

- Events resulting in loss of load
  - With load loss more than 50 MW
  - MW lost
  - Numbers of customer affected

- Interconnection frequency response
- Activation of under frequency load shedding
- System voltage performance
- Interconnection reliability operating limit/ system operating limit (IROL/SOL) exceedances
- Automatic transmission outages caused by protection system incorrect operation
- Element availability percentage (APC)
- Transmission system unavailability

These metrics should also be considered for standardization by the IEC. In this context, industry feedback suggests that it is not the actual reliability *goal* that should be standardized, just the definition of how to meet that goal. For example, electricity transmission businesses will often aim for N-1 reliability, meaning supply is not affected if only one circuit fails in the network. However, some transmission businesses may aim for N-2 reliability (ability to cope with 2 failures without supply interruption), whilst electricity distribution network businesses may aim for N-0, meaning any failure will cause a supply outage. Which of these goals should be chosen is likely best left to the network business, but how the goal is measured can be standardized.

Ultimately, it should be a relatively straightforward exercise for an organization such as the IEC to harmonize the various reliability metrics and calculation methods from around the world in one international standard. With a common language and understanding of what such metrics mean, electricity network businesses and broader stakeholders will be able to compare and benchmark the performance of electricity systems worldwide.

5.2 Financial indicators

Financial metrics are another key long-term performance indicator used by electricity network businesses in asset management. Annex B of CIGRE TB 367 [15] provides a number of examples of financial indicators used by 19 electricity transmission and distribution network businesses. When the project team surveyed such businesses from around the world, common financial indicators they claimed to use included:

- Net income after/before tax
- Credit rating
- Earnings before interest, taxes, depreciation, and amortization (EBITDA)
- Operating cash
- Operating, maintenance and administrative expenses
- Return on equity
- Cash flow (forecasting accuracy)
- Controllable unit cost method
- Economic value added
- Operating income
- Interest coverage
- Debt/equity ratio
- Capital financing ratio
- Net profit ratio
- Minimum solvency ratio

Of this list, the most commonly listed metric was net income after/before tax. These metrics are basically calculated according to commonly applied procedures such as general accounting rules, accounting regulations and various methods of financial analysis.

5.3 Safety

The safety of employees and customers constitutes the highest priority of most electricity network businesses around the world, and so asset management practice also includes a range of safety performance indicators that are considered by those planning and executing asset

management programmes. A range of commonly used industry safety indicators is shown in Annex B of CIGRE TB 367 [15]. Commonly used indicators include:

- Accident severity rate
- Lost time injury frequency rate (or lost time incident rate)
- All injury frequency rate
- Recordable incident rate
- Preventable vehicle accidents
- Safety management system activities
- Total recordable incident rate
- Disabling injury incidence rate
- Disabling and medical aid injuries
- Frequency severity index
- Medical care survey
- Average percentage of ill employees

Many of these indicators measure similar impacts, and the above list could readily be harmonized into a common set of metrics across electricity network businesses around the world. Again, even when businesses use the same measure, the actual definition of how the measure is calculated often varies across jurisdictions and organizations. Standards can play a significant role here in identifying a set of health and safety measurements for electricity distribution and transmission authorities to use, and providing a clear way to calculate these.

5.4 Customer impact

Customer impact is another long-term indicator that is often used by electricity network businesses to measure their performance. Customer impact is usually some measurement of customer satisfaction, but how this is calculated varies significantly. Annex B of CIGRE TB 367 [15] provides some examples of how customer satisfaction can be interpreted. For example, “customers” may refer to the energy customers or could alternatively designate the stakeholders (whether public or private) of the network business. Such satisfaction may be measured through the results of customer/stakeholder meetings, detailed surveys, and/or some measurement index associated with such events.

Clearly, an understanding of customer satisfaction is a key aspect of measuring the performance of an electricity network business. However, the measurement of customer satisfaction is perhaps one of the least mature performance metrics in the electricity network business industry. With massive variation on how to measure this factor, and even differences in the definition of what a customer is, there is a significant opportunity for standards to provide a number of key customer impact metrics, with a clearly defined definition that can be used worldwide.

5.5 Employee impact

Employees are another key stakeholder in any electricity network business, and so understanding the impact of asset management practices on a electricity network businesses’ employees can be another long-term indicator of some benefit. When the project team surveyed electricity network businesses regarding their performance metrics, 4 companies listed employee-impact related metrics. These included:

- Employment engagement index – alignment, capability, resources, motivation (ACRM)
- Employee survey index
- Annualized training days per employee
- Annualized average sick day per employee – sick leave
- HR development strategies and initiatives
- Succession management
- Staff retention strategy and initiatives

- Human resources sustainability index
- Racial equality
- Gender equality
- Employee satisfaction survey
- Company medical care survey
- Percentage of non-entry level (NEL) positions filled by external applicants
- Percentage of designated group members in network business workforce

As the drive to understand employee satisfaction and wellbeing grows across the electricity network business sector, a common and standardized set of metrics to measure this factor would be of significant benefit worldwide.

5.6 Asset management standards for the asset supply chain

When considering the challenge of network business asset management, it is critical to keep in mind the broader asset supply chain, including equipment manufacturers and contractors (the comments in this section apply to both). Whilst the asset management challenges facing electricity network businesses have been described throughout this White Paper, equipment manufacturers face their own challenges. Manufacturers must try to operate a long-term business in an industry that often has relatively peaky purchasing patterns. They need to maintain the ability to service legacy equipment, while keeping up with changing technologies, and to maintain capital-intensive manufacturing facilities. Additionally, manufacturers need to manage their human resources, attempting to maintain an ongoing knowledge base in an often aging workforce.

In order to maintain operations amid the challenges cited above, and to operate a relatively stable business, equipment manufacturers need to have a close relationship with the users and purchasers of their equipment. By understanding the likely future demand for particular items of equipment (which often have long manufacturing lead times), and remaining aware of current technical needs and failure rates, manufacturers can keep up with the needs of their customers, while balancing their own internal constraints.

With information sharing between electricity network businesses and equipment manufacturers being a key aspect of a healthy electricity network asset management chain, standards can play a significant role in facilitating such communications. Almost all the standards contributions discussed in the previous sections of this White Paper will benefit equipment manufacturers as well as electricity network businesses, and it should be noted that equipment manufacturers played an active role in the industry workshops held when preparing this White Paper. Whether facilitating communications through a common definition of terms and performance metrics, or providing an international database of faults and failure characteristics, new asset management standards will bring significant benefit to the entire electricity distribution and transmission ecosystem.

Section 6

Existing standards and guidelines

There currently exists a range of international standards or specifications of relevance to the challenges of electricity network asset management.

6.1 ISO 55000 series and PAS 55

The ISO 55000 series (ISO 55000, ISO 55001 and ISO 55002) is a well-known general asset management standard published in 2014 and a derivative of the PAS 55 standards originally published by the British Standards Institute. These standards are general in nature, targeted at the management of large physical assets. They were intended to be particularly relevant to gas, electricity and water utilities and to road, air and transport systems, in both the public and private sectors.

At least 2 clauses in ISO 55001 mandate activities that could significantly benefit from the suggestions in this White Paper:

- Clause 6.1: "The organization shall plan actions to address these risks" (relating to asset failures and their subsequent impacts). The recommendations in Section 5 of this White Paper specifically address this requirement, looking at how standards can assist the planning and prioritization of asset management actions.
- Clause 9.1: "The organization shall determine what needs to be monitored and measured, the methods for monitoring (...), when the monitoring and measuring shall be performed, when the results from monitoring and measurement shall be analysed and evaluated". This matches the recommendations in Sections 3 and 4 of this White Paper.

More comments on the application of ISO 55001 and related standards to electricity network businesses can be found in:

- Section 2.1 of CIGRE TB 597 [8], which describes the application of the ISO 55000 series to the electricity sector
- Section 4.1 of CIGRE TB 597 [8], entitled *TenneT and ISO 55000*
- Section 5.2.2 of CIGRE TB 597 [8], entitled *Recommendation of ISO 55000 Application to ETCs*

6.2 Other standards

The committee for ISO 55000 has suggested that application of this standard be made in partnership with other standards including:

- ISO 9001, *Quality management systems – Requirements*
- ISO 14001, *Environmental management systems – Requirements with guidance for use*
- ISO 50001, *Energy management systems – Requirements with guidance for use*
- ISO 31000, *Risk management – Principles and guidelines*
- ISO/IEC 17021, *Conformity assessment – Requirements for bodies providing audit and certification of management systems*
- ISO/IEC 19770, *Information technology – IT asset management*
- ASTM E53, Asset management standards
- Global Forum on Maintenance and Asset Management (GFMAM) publications

- Society for Maintenance and Reliability Professionals (SMRP) publications
- Institute of Asset Management's (IAM) body of knowledge

Other standards should serve as a useful reference, including:

- IEC 60300, *Dependability management*
- IEC 60812, *Analysis techniques for system reliability – Procedure for failure mode and effects analysis (FMEA)*
- ISO/IEC 31010, *Risk management – Risk assessment techniques*
- IEC 61025, *Fault tree analysis (FTA)*
- IEC 61078, *Analysis techniques for dependability – Reliability block diagram and boolean methods*
- IEC 61649, *Weibull analysis*
- IEC 60706, *Maintainability of equipment*
- IEC 61850, *Communication networks and systems for power utility automation*
- IEC 61968-11, *Application integration at electric utilities – System interfaces for distribution management – Part 11: Common information model (CIM) extensions for distribution*
- IEC 61970-452, *Energy management system application program interface (EMS-API) – Part 452: CIM model exchange specification*
- IEEE 1366, *IEEE Guide for Electric Power Distribution Reliability Indices*

6.3 Standardization – what to leave out

In preparing this White Paper, as well as consulting on where standards or guidelines may benefit the asset management process, the project team also consulted electricity network businesses and other stakeholders regarding what items they thought should be left out of standards. A range of opinions were expressed in this regard, however a number of key themes emerged:

- Electricity network businesses need to be free to manage their own unique situation and business. Thus standards may specify particular goals or how to measure these goals, but they should not mandate particular asset management practices.
- Expectations of electricity supply reliability and other performance metrics vary significantly around the world. Standards should not specify one particular reliability target, but rather provide a range of reliability indicators, which electricity network businesses or other stakeholders can choose from to match their own situation.
- Whilst standards should not be overly prescriptive in describing certain business practices, they may mandate particular practices to follow in order to achieve, for example, a particular reliability rating. Electricity network businesses or other stakeholders should then be left to their own devices to decide which reliability rating they wish to strive for.
- International standards prepared by the IEC should focus on technical issues specific to transmission and distribution network asset management challenges. Broader considerations around optimal management processes for asset management can be left to more general standards such as the ISO 55000 series.
- The electricity network and distribution industry is currently going through a period of incredible change, ranging from the development of new technologies, such as smart grid technologies, to the elaboration of changing business practices from the massive uptake of distributed generation. It will be critical to ensure that anything standardized is able to stay abreast of the changing industry, its technology and business practices.

Section 7

Conclusion and recommendations

Worldwide, the electricity industry is facing a number of very significant challenges, the first of which listed by many electricity network business CEOs is the issue of asset management. Whether owning an asset base nearing its expected end of life, dealing with regulatory or funding pressures on maintenance expenditure or the challenges posed by an aging workforce, electricity network businesses and broader stakeholders face a number of critical asset management challenges that will have profound effects on power supply quality and reliability, financial expenditure and future business practices.

Amid the broad range of asset management challenges today, there exists a complete lack of broadly accepted standards or practices for electricity network asset management. Whether calculating metrics to report on the performance of their system or likely failure rates of an aging asset base, or trying to prioritize amongst various asset management options, electricity network businesses around the world adopt vastly different approaches and practices to almost all aspects of asset management. Whilst some level of variety is important to ensure that electricity network businesses can tailor solutions to their given environment, the current level of diversity suggests an overall lack of understanding of best-practice asset management procedures and significant difficulty in even benchmarking across current network business practices or performance.

International standards and guidelines generated by organizations such as the IEC have a significant role to play in improving this situation and having a positive impact on meeting the challenges of electricity network asset management. International standards and guidelines can bring a range of benefits to electricity network businesses and their broader stakeholders, including:

- If common standards for reporting on the age and condition of assets existed, electricity network businesses around the world could gain the confidence and trust of regulators, governments and the public, when staking funding applications based on the age and claimed upgrades of their equipment.
- Having standardized practices for asset management could significantly increase the trust and transparency around asset management and investment decisions, for all stakeholders in the electricity network business industry, as everyone could refer to independently established guidelines for best-practice asset management.
- Having standards for asset management would allow electricity network businesses to benchmark themselves against other companies in different jurisdictions or geographies.
- Standards for asset management could be used as a communication and education tool to understand and explain the best-practice methods in asset management, in both developed and developing nations.

This document has suggested a range of areas where international standards could be written to contribute to the broader practice of asset management in electricity network businesses.

Specific topics for new IEC International Standards include:

- Inspection and diagnosis methods and criteria for major equipment
- Measurement and reporting of fault and equipment failure data
  - Analysis methods, and common deterioration modes or faults for major equipment
  - Best-practice examples of remedial actions for major equipment, ranging from replacement to partial replacement or refurbishment
- Methods for lifetime estimation and reporting for major equipment
- Life cycle cost calculation
- Risk evaluation methods
- Calculation of health indices for major equipment
- Prioritization methods for asset management
- System performance indices (CAIDI, SAIDI, SAIFI, etc.)

7.1 Key recommendations

Based on the research behind this White Paper and detailed surveys of electricity network businesses, their current asset base and asset management practices, a number of recommendations can be made for consideration by the IEC and broader stakeholders:

1) Consider the elaboration of detailed international standards or guidelines to introduce a common language across the electricity network business industry regarding current system performance. Metrics such as SAIDI and SAIFI are vital to the benchmarking of electricity network performance, yet such metrics are calculated differently around the world.

2) Investigate the introduction of a central database, or related system that can capture historical performance, failure information, and maintenance articles for major electricity network equipment. Having an openly accessible worldwide database on how various items of equipment (from different manufacturers, etc.) fail, and providing example methods of repair or sources of spare parts, will benefit the entire electricity network industry, particularly as equipment is nearing the planned end of its life.

3) Consider the introduction of international standards to classify reliability targets or performance for electricity networks. Such standards can allow electricity network businesses to communicate their targeted performance or service level for the network, and then provide guidance regarding all levels of asset management needed to achieve a certain performance target.

4) Investigate the introduction of a wide range of asset management procedural standards or guidelines for electricity network businesses. These could include international standards or guidelines for functions such as:

   a) Inspection and diagnosis methods and criteria for major equipment

   b) Measurement and reporting of fault and equipment failure data

   c) Best-practice examples of remedial actions for major equipment faults, ranging from replacement to partial replacement or refurbishment

   d) Methods for lifetime estimation and reporting for major equipment

   e) Life cycle cost calculation

   f) Risk evaluation methods

g) Calculation of health indices for major equipment

h) Prioritization methods for asset management

5) In many cases, the standards suggested above may not need to be developed in isolation or to start from scratch. Many guidelines for asset management already exist from organizations such as CIGRE in their series of technical brochures on asset management procedures. In this context, it is useful to use such references as comprehensive starting points for subsequent international standards or guidelines. On the other hand, it is often difficult for a person who is unfamiliar with CIGRE to know of or identify such technical brochures. As such, it is recommended that IEC and CIGRE collaborate to serve as an intermediary between appropriate brochures and parties that may benefit from them.

6) Whilst there is significant opportunity for the introduction of new standards to harmonize electricity network asset management practices around the world, and such harmonization is likely to generate numerous benefits, care should also be taken to ensure organizations have sufficient freedom to tailor practices to their own business or operating environment. Such an outcome may be realized through standards that provide a range of alternative practices (for example, within different reliability targets), or through the provision of best-practice guidelines that act as key reference pieces for the broader industry, but whose uptake remains optional.

Annex A

Monitoring and maintenance procedures and intervals

This annex provides examples of monitoring and maintenance items and intervals for common electricity network assets.

A.1 Transformer

CIGRE TB 445 [19], summarized in Table A-1, provides the typical maintenance items and intervals for power transformers. Table A-2 lists common failures in power transformers that can be identified by electrical tests or dissolved gas analysis.

In addition to the faults in Table A-2, paper depolymerisation, degradation of winding tightening force and streaming electrification in transformer oil are well-known deterioration modes for power transformers. Diagnosis and evaluation methods for these faults are presented below.

Paper depolymerisation

The approximate strength of the insulation paper can be estimated by the polymerization degree, which is measured by the amount of products including the furfural, CO, CO_2 and acetone. In addition, recent diagnosis methods have been proposed to estimate strength based on the amount of methanol [20].

Table A-1 | Maintenance intervals for power transformers [19]

Action	Task interval			Remark
	Light	Regular	Intensive	
Visit	6 m	1 m	1 d	In service
Detailed visual inspection	1 y	3 m	2 w	In service
DGA	2 y	1 y	3 m	Task interval may differ with monitoring
Oil tests	6 y	2 y	1 y	
Cooling system cleaning	Conditional	Conditional	Any interval	Outage may be required
Accessories verification	12 y or conditional	6-8 y	1-2 y	Outage required
Electrical basic tests	Conditional	Conditional	Any interval	Outage required
Insulation tests (DF or PF)	Conditional	6-8 y	2-4 y	Outage required
OLTC internal inspection	12 y	6-8 y	4 y	Consider number of operation, technology and manufacturer recommendations

Degradation of winding tightening force

A method to estimate the residual tightening strength based on CO and CO_2 is being studied in Japan. Withstanding force is evaluated by the initial tightening force and the result of the degradation diagnosis.

Streaming electrification in aged transformer oil

The diagnosis method with streaming electrification proposed by Japan evaluates the risks of the transformer against streaming electrification and classifies them into 3 ranks [21], as shown in Table A-3.

Table A-2 | Electrical tests and dissolved gas analysis diagnostic matrix [19]

	Type of problem	Magnetic circuit integrity	Magnetic circuit insulation	Winding geometry	Winding/Bushing/OLTC continuity	Winding/Bushing/Insulation	Winding turn to turn insulation
	Diagnostic technique						
Basic electrical	Winding ratio	•					
	Winding resistance			•			
	Magnetization current	•					•
	Capacitance and DF/PF		•		•	•	•
	Leakage reactance				•		
	Insulation resistance		•			•	
	Core ground test					•	
Advanced electrical	Frequency response of stray losses			•	•		
	Frequency response analysis	•			•	•	•
	Polarization/Depolarization		•				
	Frequency domain spectroscopy		•				
	Recovery voltage method		•				
	Electrical detection of PD	•	•				
	Acoustical detection of PD	•	•				
	UHF detection of PD	•	•				
	Dissolved gas analysis	•	•	•		•	•

Table A-3 | Rank of the transformer for streaming electrification [21]

Rank	Concept of classification	Evaluation item	
		Accumulating chare density	**Deterioration condition**
I	Transformer that has potentiality of electrostatic discharge at present or near future based on the knowledge of increase risk due to deterioration.	• Less than 60 nC/cm^2 • 60 nC/cm^2 and over and less than 80 nC/cm^2, with age of 20 years and over	• Detects small amount of C2H2 • Electrified degree exceeding the control value
II	Transformer that has little potentiality of electrostatic discharge at present, but has possibility in the future.	• 60 nC/cm^2 and over and less than 80 nC/cm^2, with age of less than 20 years	
III	Transformer that has no potentiality of electrostatic discharge at present, and has little possibility in the future.	• 80 nC/cm^2 and over	

A.2 Gas circuit breaker

As described in CIGRE TB 165 [22], most of the maintenance methods for switchgear use time-based maintenance practices. Typical activities as reported in CIGRE TB 381 [23] are shown in Figure A-1 and Table A-4.

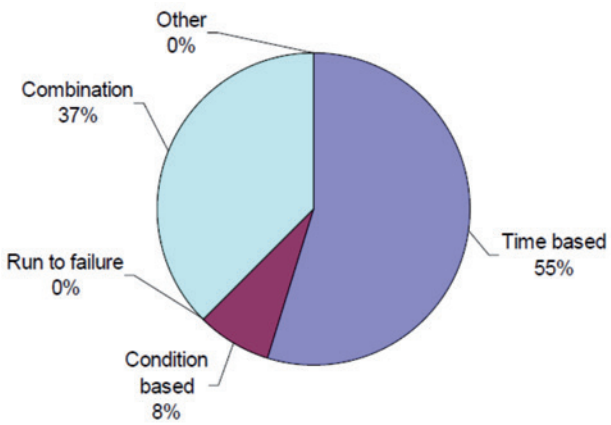

Figure A-1 | Circuit breaker maintenance approaches [23]

Table A-4 | Typical maintenance and inspection for circuit breakers [23]

Description of inspection and maintenance services (due after time or wear)		Remarks
time	**wear**	
Visual check (VK) after 8 years		Switchgear remains in service; the bays must be isolated one after the other. The compartments need not be opened.
Visual check (VK) after 16 years	Circuit-breaker: after 3 000 mechanical operating cycles	Switchgear remains in service; the bays must be isolated one after the other. The compartments need not be opened.
Major inspection (MI) after 24 years	Circuit-breaker: after 6 000 mechanical operating cycles High-speed earthing switches and work in progress earthing switches: after 2 000 mechanical operating cycles Disconnecter and earthing switch module: after 2 000 mechanical operating cycles	Switchgear is taken out of service, either completely or in sections, depending on the amount of work involved. **Gas compartments need be opened.**
Contact system check (CC)	Circuit-breaker: if the maximum allowable number of fault current operations according to digit 4.1 has been reached. After a maximum of 6 000 fault current operations! High-speed earthing switch: after the second closing operation onto live conductors	Module must be isolated. **Gas compartment is opened.**
Visual check (VK) after 32 years	The inspection and maintenance schedule is repeated.	

A.3 Insulated cable

For insulated cables, CIGRE TB 358 [12] lists a range of common defects, repeated below in Table A-5, together with common maintenance methods from CIGRE TB 279 [10], as shown in Tables A-6 to A-9.

Table A-5 | Most common insulated cable defects by cable type [12]

Item	Type of defect	Self contained fluid filled cables	High pressure fluid filled cables	Gas pressure cables	Extruded cables
1	3rd party cable damage	X	X	X	X
2	3rd party oversheath damage resulting in brittleness, external contamination of oils, solvents, bitumen, etc.	X			X
3	3rd party damage to metal sheath, corrosion or fatigue	X			X
4	Ingress of water into insulation	X			X
5	External damage due to cable movement caused by heavy traffic/poor subsoil conditions/unstable ground	X			X
6	External mechanical stress due to ground changes, thermal expansion-contraction/ improper clamping	X			X
7	Assembly error causing local increase of electrical stress in joints and terminations	X	X	X	X
8	Leakage of internal insulating oil from termination	X	X	X	X
9	Movement of cable due to thermal cycling or poor clamping	X			X
10	Water ingress into link boxes	X			X
11	Failure of forced cooling system (where fitted)	X	X	X	X
12	Leaking or damaged steel pipe due to corrosion		X	X	
13	Failure of oil/gas feeding and pressurization system due to oil leaks in associated pipework, reservoir tank, oil pump system failure, faulty gauges		X	X	

Table A-6 | Diagnostic indicators for low pressure fluid filled cables [10]

Tool	Description of method	Events/cause detected	Comments	On-line/Off-line
1) Cable route inspection (for third party activities)	Visual inspection of the cable route to observe any third party activities near the cable route	Prevention of damage by third party	Well established	On-line
2) Indication of falling oil pressure	Continuous measurement of oil pressure and/or low pressure alarms	Damaged metal sheath leakage from termination	Well established	On-line
3) Serving test	Measurement of the oversheath insulation resistance by HV testing Location of any defects and repair	Damaged outer sheath	Well established	Off-line
4) Temperature measurement	Measurement of temperature along the route by optical fibre (DTS)	Increased temperature causing thermal ageing Failure of cooling system	Well established technique, but requires fibre to be installed on the system design	On-line
5) Partial discharge measurement	Measurement of discharges within the cable system	Defects and degradation of insulation	Under development. Effectiveness dependant upon system design	On-line/Off-line
6) Chemical and physical analysis of insulating oil	Fluid samples taken from the cable system and tested for: – DGA – Tan delta – Water content – Particles – etc.	Thermal ageing of insulation (caused by different events)	Well established technique, relies on regular testing regime since interpretation of individual DGA results not clearly understood	Off-line
7) X-ray of accessories	Use of X-ray on accessories	Movement of cable causing ferrule unplugging Incorrect assembly of joint connector.	Well established but significant health and safety issues and practical application limitations	Off-line
8) Inspection of cable system	Visual inspection of all components of the cable system for damage, leaks, corrosion, etc.	Visual damage, leaks, corrosion, etc.	Well established	On-line
9) Inspection of termination for ferrule retraction	Internal inspection and measurement of ferrule movement	Movement of cable causing ferrule unplugging	Well established	Off-line
10) Regular gauge maintenance and calibration Regular testing of gauge/transducer alarm functionality	Hydraulically initiate the gauge/sensor alarm contacts Pressure alarm tests for device to control room	Prevention of failure in alarm system Prevention of false alarm	Well established	Off-line
11) Sheath voltage limiter test	Measurement of increased sheath standing voltage	Failure of SVL	Basic test on integrity only	Off-line
12) Bonding systems test	Checking the integrity of specially bonded systems by measurement of insulation resistance and/or circulating current in the screen	Loss of cross-bonding function	Well established	Off-line

Table A-7 | Diagnostic indicators for high pressure fluid filled cables [10]

Tool	Description of method	Events/cause detected	Comments	On-line/Off-line
1) Cable route inspection (for third party activities)	Visual inspection of the cable route to observe any third party activities near the cable route	Prevention of damage by third party	Well established	On-line
2) Indication of falling fluid pressure	Continuous measurement of fluid pressure and/or low pressure alarms	Damaged steel pipe leakage from termination	Well established	On-line
3) Electrical test on pipe coatings	Insulation resistance of jacket	Damaged steel pipe	Under development	Off-line
4) Inspection of cathodic protection system	Measurement of pipe to soil potential	Damaged steel pipe	Requires cathodic protection to be installed and operating properly. More effective when trends are analyzed	On-line
5) Temperature measurement	Measurement of temperature along the route by optical fibre (DTS)	Increased temperature causing thermal ageing Failure of cooling system	Well established technique, but requires fibre to be installed on the system	On-line
6) Thermal backfill survey	Measure thermal resistivity of backfill in vicinity of cable	Thermal ageing of insulation caused by overload, short-circuit, hot spots	Effective where a problem is suspected	On-line
7) Chemical and physical analysis of papers and impregnant	Measure the following: – folding strength – tear strength – burst strength – degree of polymerization – extension to break – tensile strength	degradation of insulation (caused by different events)	Well established, but the interpretation of the results of these tests is not yet clearly understood in terms of deciding the end of life of the cable	Off-line
8) X-ray of accessories	Use of X-ray on accessories	Movement of cable causing ferrule unplugging Incorrect assembly of joint connector	Well established but significant health and safety issues and practical application limitations	Off-line
9) Inspection of cable system	Visual inspection of all components of the cable system for damage, leaks, corrosion, etc.	Visual damage, leaks, corrosion, etc.	Well established	On-line
10) Inspection of termination for ferrule retraction	Internal inspection and measurement of ferrule movement	Movement of cable causing ferrule unplugging	Well established	Off-line
11) Inspection of pumping system	Visual and mechanical check of pump, pipework, etc. when oil pressure alarm is activated	Oil pump system failure	Very effective	Off-line
12) Regular gauge maintenance and calibration Regular testing of gauge/transducer alarm functionality	Hydraulically initiate the gauge/sensor alarm contacts Pressure alarm tests for device to control room	Prevention of failure in alarm system Prevention of false alarm	Well established	Off-line

Table A-8 | Diagnostic indicators for gas pressure cables [10]

Tool	Description of method	Events/cause detected	Comments	On-line/Off-line
1) Cable route inspection (for third party activities)	Visual inspection of the cable route to observe any third party activities near the cable route	Prevention of damage by third party	Well established	On-line
2) Indication of falling gas pressure	Continuous measurement of gas pressure and/or low pressure alarms	Damaged steel pipe leakage from termination	Well established	On-line
3) Electrical test on pipe coatings	Insulation resistance of jacket	Damaged steel pipe	Under development	Off-line
4) Inspection of cathodic protection system	Measurement of pipe to soil potential	Damaged steel pipe	Requires cathodic protection to be installed and operating properly. More effective when trends are analyzed	On-line
5) Temperature measurement	Measurement of temperature along the route by optical fibre (DTS)	Increased temperature causing thermal ageing Failure of cooling system	Well established technique, but requires fibre to be installed on the system	On-line
6) Thermal backfill survey	Measure thermal resistivity of backfill in vicinity of cable	Thermal ageing of insulation caused by overload, short-circuit, hot spots	Effective where a problem is suspected	On-line
7) Chemical and physical analysis of papers and impregnant	Measure the following: – folding strength – tear strength – burst strength – degree of polymerization – extension to break – tensile strength	Insulation (caused by different events)	Well established, but the interpretation of the results of these tests is not yet clearly understood in terms of deciding the end of life of the cable	Off-line
8) X-ray of accessories	Use of X-ray on accessories	Movement of cable causing ferrule unplugging Incorrect assembly of joint connector	Well established but significant health and safety issues and practical application limitations	Off-line
9) Inspection of cable system	Visual inspection of all components of the cable system for damage, leaks, corrosion, etc.	Visual damage, leaks, corrosion, etc.	Well established	On-line
10) Inspection of termination for ferrule retraction	Internal inspection and measurement of ferrule movement	Movement of cable causing ferrule unplugging	Well established	Off-line
11) Regular gauge maintenance and calibration Regular testing of gauge/transducer alarm functionality	Hydraulically initiate the gauge/sensor alarm contacts Pressure alarm tests from device to control room	Prevention of failure in alarm system Prevention of false alarm	Well established	Off-line

Table A-9 | Diagnostic indicators for extruded cables [10]

Tool	Description of method	Events/ cause detected	Comments	On-line/Off-line
1) Cable route inspection (for third party activities)	Visual inspection of the cable route to observe any third party activities near the cable route	Prevention of damage by third party	Well established	On-line
2) Serving test	Measurement of the oversheath insulation resistance by HV testing Location of any defects and repair	Damaged outer sheath	Well established	Off-line
3) Tan δ measurement	Measurements of increased power factor	Ingress of water in insulation area	Under development. The methods have only been developed for medium voltage cables, and are at the moment not possible to use on HV cables	Off-line
4) Temperature measurement	Measurement of temperature along the route by optical fibre (DTS)	Increased temperature causing thermal ageing Failure of cooling system	Well established technique, but requires fibre to be installed on the system	On-line
5) Partial discharge measurement	Measurement of discharges within the cable system	Defects and degradation of insulation Assembly errors in accessories	Well established for accessories. Increased partial discharges are only detectable in cables during a short time before failure	On-line/Off-line
6) Chemical and physical analysis of insulating fluid of terminations	Fluid samples taken from the cable system and tested for: – DGA – Tan delta – Water content – Particles – etc.	Thermal ageing of insulation (caused by different events)	Well established technique, relies on regular testing regime since interpretation of individual DGA results not clearly understood	Off-line
7) X-ray of accessories	Use of X-ray on accessories	Movement of cable causing ferrule unplugging Incorrect assembly of joint connector	Well established but significant health and safety issues and practical application limitations	Off-line
8) Inspection of cable system	Visual inspection of all components of the cable system for damage, leaks, corrosion, etc.	Visual damage, leaks, corrosion, etc.	Well established	On-line
9) Inspection of termination for ferrule retraction	Internal inspection and measurement of ferrule movement	Movement of cable causing ferrule unplugging	Well established	Off-line
10) Sheath voltage limiter test	Measurement of increased sheath standing voltage	Failure of SVL	Basic test on integrity only	Off-line
11) Bonding systems test	Checking the integrity of specially bonded systems by measurement of insulation resistance and/or circulating current in the screen	Loss of cross-bonding function	Well established	Off-line

A.4 Overhead lines

CIGRE TB 230 [24] summarizes maintenance approaches for overhead lines, with one of the key differences being tower maintenance, as shown in Table A-10. Also, this brochure lists the special tools for such inspections.

Main focus items for overhead line tower maintenance from CIGRE TB 230 include:

- Vegetation in the area of the support
- Minor corrosion
- Paint deterioration
- Deformed support elements
- Loose bolts

Special tools for inspection of overhead line towers include:

- Galvanization thickness meter
- Paint thickness meter
- Deflection/torsion of supports (for example, with theodolite)
- Stay tension measurement
- Support leg corrosion detector
- Steel corrosion metrology
- Guy/stay wire corrosion detector
- Geometry (photogrammetry)
- Endoscope device

Table A-10 | Periods/samples for overhead line maintenance [24]

Inspection from	General line (OHL)				Strategic line (OHL)			
	Period (year)		Sample (%)		Period (year)		Sample (%)	
	Median	Mean	Median	Mean	Median	Mean	Median	Mean
Car	1,0	1,4	49	57	0,8	0,8	65	66
Ground	1,0	1,4	100	87	1,0	1,3	100	90
Climbing	2,8	4,2	33	53	1,0	3,0	68	60
Helicopter	1,0	1,5	100	94	1,0	1,5	100	95

Annex B

Deterioration modes for electrical power network equipment

Examples of deterioration modes for various common electrical power network equipment are shown in this annex.

B.1 Transformer

Paper depolymerisation

Depolymerisation of insulation paper caused by cumulative heating leads to the decrease of strength of the paper. Figure B-1 shows the relationship between paper depolymerisation and the amount of CO_2+CO and furfural which are produced by aging.

Degradation of winding tightening force

Dimensional contraction of the insulator, such as pressboard (see Figure B-2), caused by the thermal deterioration leads to the degradation of winding tightening force. This occurrence has only recently started to be recognized in aging equipment.

Streaming electrification in aged transformer oil

With addition of the deterioration of the pressboard, alteration of sulfur contained in insulating oil can cause an increase of electrostatic charging tendency. This is one factor which can impact the lifetime of a power transformer.

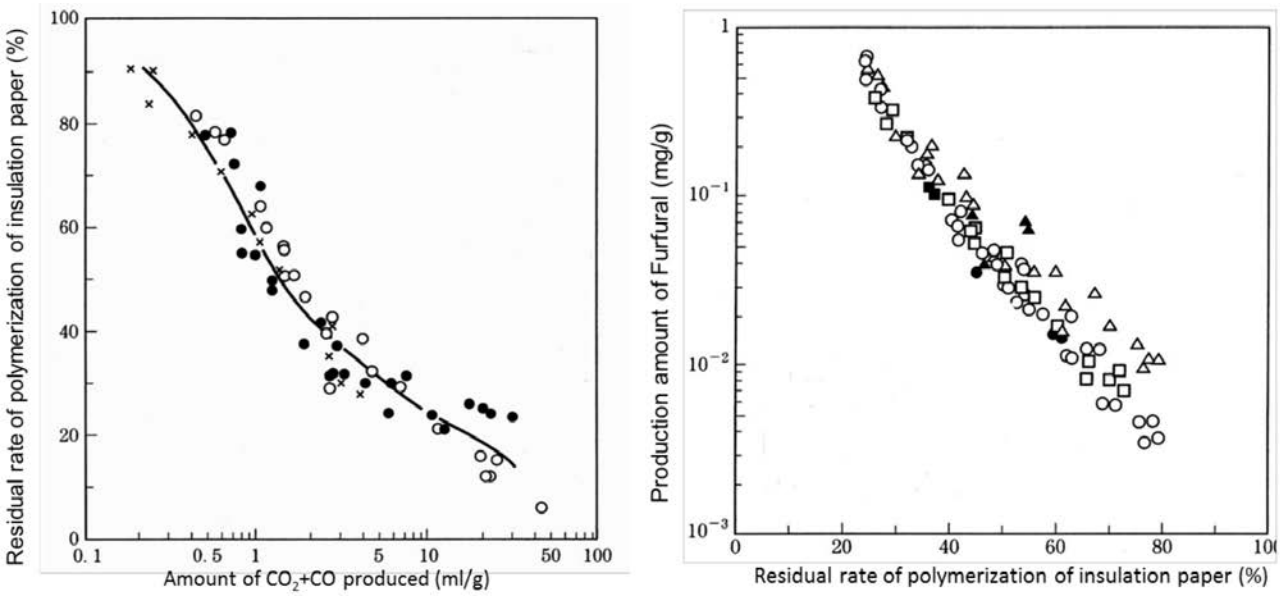

Figure B-1 | Relationship between residual rate of polymerization of insulation paper and amount of CO_2+CO (left), amount of furfural (right) [25]

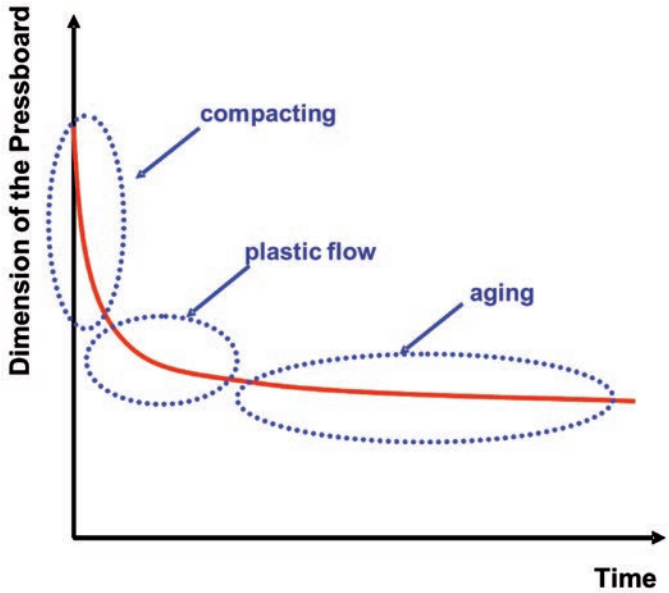

Figure B-2 | Contraction process of the pressboard

B.2 Gas circuit breaker

Common deterioration modes for gas circuit breakers include:

- Exhaustion of arc quench chamber
- Wear of moving parts in gas circuit breaker
- Degradation of gas sealing performance by thermal deterioration

Number of times of activation and accumulated energy of the interrupted current could be possible criteria for repairing or replacing the inside of the arc quench chamber. On the other hand, external diagnosis by inspection of moving parts in gas circuit breakers is often difficult, since the mechanism differs depending on the manufacturer and type. Furthermore, the gas sealing performance in such circuit breakers varies significantly depending on the material of O-ring and waterproof structure. Lifetime of the seals can range from 21 to 91 years, depending on the material, when sealing lifespan is considered as the moment when the compression set rate becomes 80%.

B.3 Insulated cable

CIGRE TB 358 [12] summarizes the deterioration factors of extruded cable, as shown in Figure B-3. The most common failure mode of XLPE cable without a water barrier is water treeing and the current situation is described as the transition stage from random failure period to wear-out failure period using a bathtub curve. In CIGRE TB 358, the number of expected failures is reported to be linearly to exponentially rising with time.

B.4 Overhead line tower

Corrosion of the steel is reported to be the major cause of abnormality for the overhead line support towers in CIGRE TB 230 [24]. In this brochure, the type and cause of corrosion are described as below.

Common type or cause of corrosion in overhead line towers:

- Normal weathering
- Industrial pollution

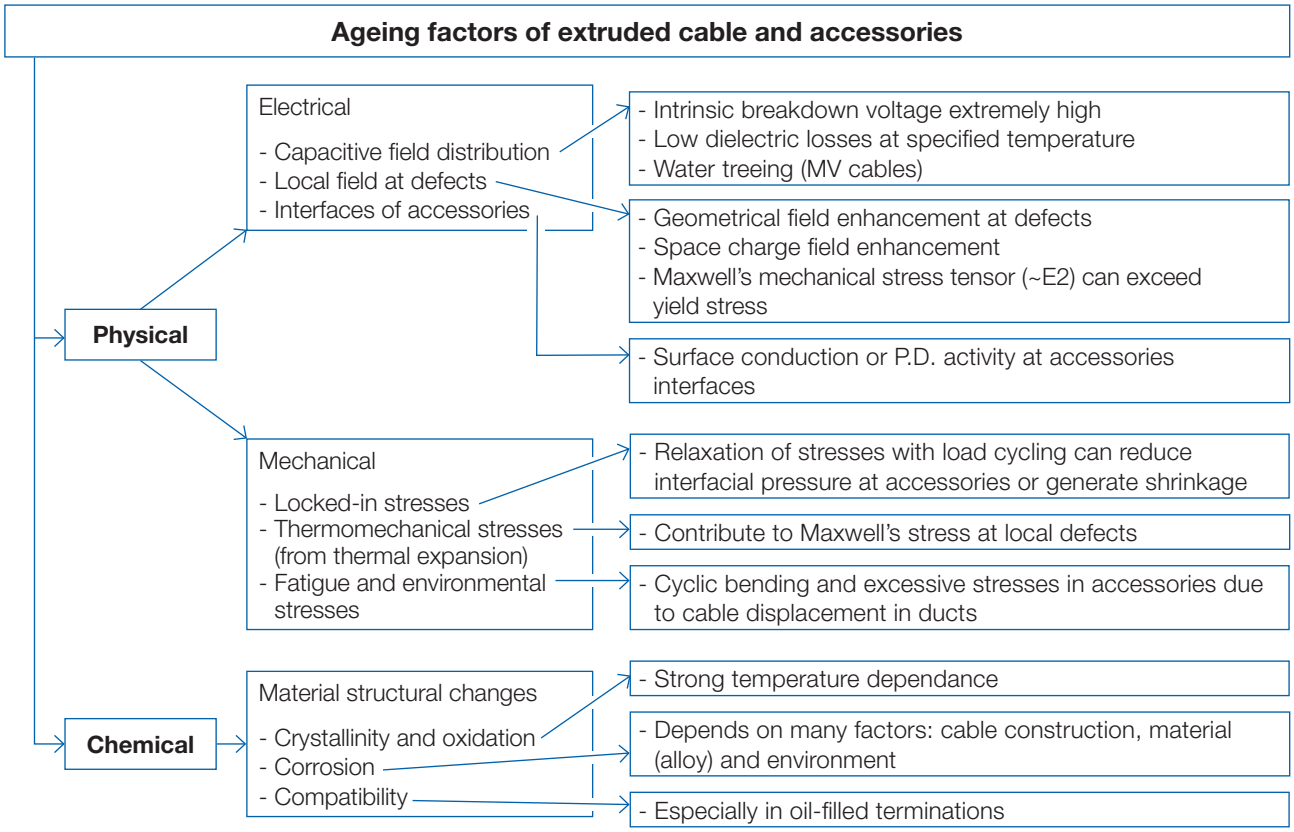

Figure B-3 | Deterioration factors of extruded cable [12]

- Salt corrosion (maritime sites)
- Gap corrosion (resulting in pack rust)
- Heavy vegetation growth in temperate zones
- High humidity in temperate zones
- Inter-crystalline corrosion of material
- High humidity in tropical zones
- Heavy vegetation growth in tropical zones

Overhead line support tower parts commonly affected by corrosion:

- Support footing area
- Nuts or bolts
- Secondary members of the steel lattice
- Complete support
- Main members of the steel lattice
- Shafts of bolts
- Washers of bolts
- Connections between bars
- Gusset plates (nodes)
- Sizes of the gusset plates
- Stays (cable)
- Stay connection (at ground/support)
- Welding seams

Annex C

Failures and failure rates for common electrical network assets

This annex provides information on the failures and failure rates for common major assets in electrical power networks.

C.1 Transformer

Table C-1 lists the failure rates of transmission system substation transformers, reported by CIGRE A2.37 [26]. The cause of these failures was also surveyed, and is shown in Figure C-1.

Table C-1 | Failure rates of substation transformers [26]

Failures and population information	Highest system voltage (kV)					
	69 ≤ kV < 100	100 ≤ kV < 200	200 ≤ kV < 300	300 ≤ kV < 500	kV ≥ 700	All
Failures	145	206	136	95	7	589
Transformer – Years	15 077	46 152	42 635	29 437	219	135 491
Failure rate	0,96%	0,45%	0,32%	0,32%	3,20%	0,43%

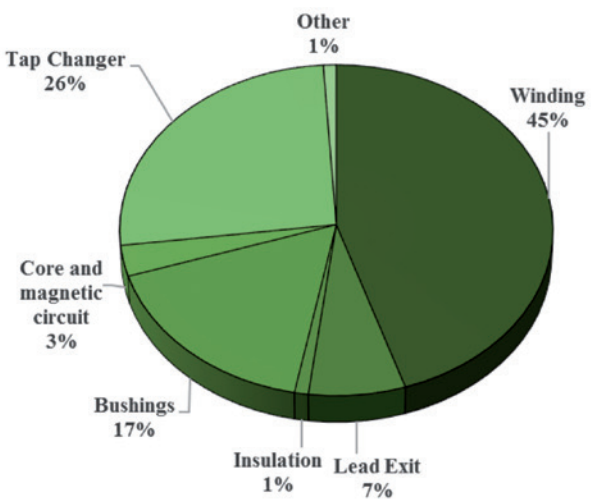

Figure C-1 | Failure locations of substation transformers [26]

C.2 Gas circuit breaker

CIGRE also performed a survey on gas circuit breakers, their year of manufacture and major failure frequencies, as shown in Figure C-2 [27]. As seen in Figure C-3, failure frequencies vary between dead-tank and live-tank circuit breakers.

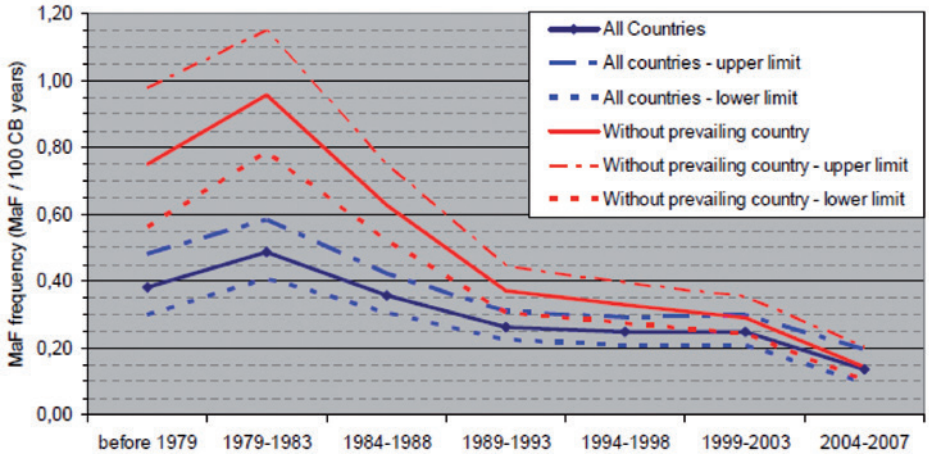

Figure C-2 | Major failure frequency as a function of circuit breaker manufacture period [27]

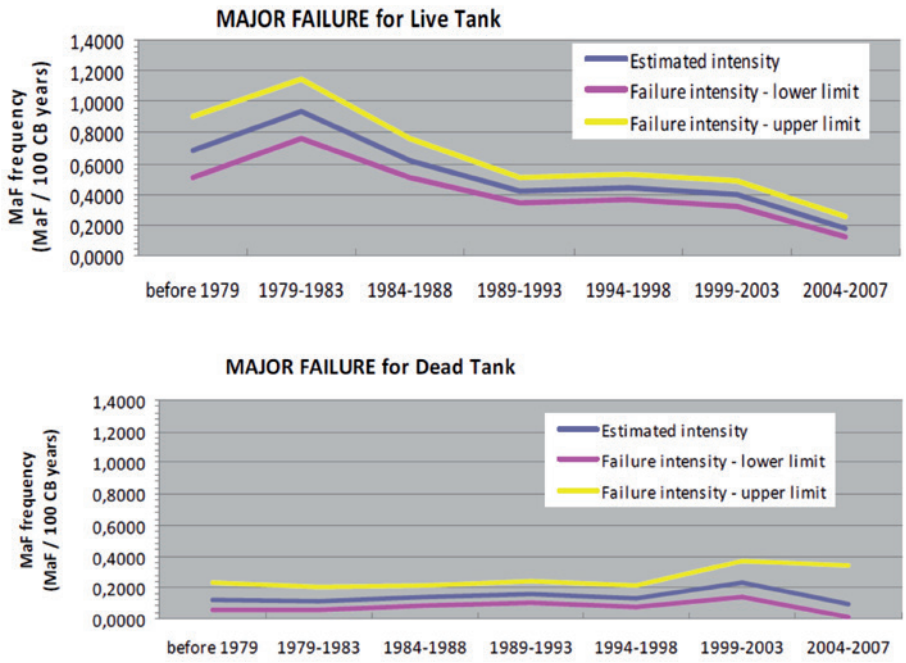

Figure C-3 | Major failure frequencies for enclosure type [27]

C.3 Insulated cable

For insulated cables, CIGRE TB 379 [28] lists the results of a survey of their failure rates.

Figure C-4 shows the trend in internal failures of land cables, whereas Table C-2 classifies each rate of failure by voltage range, cable type and accessory type.

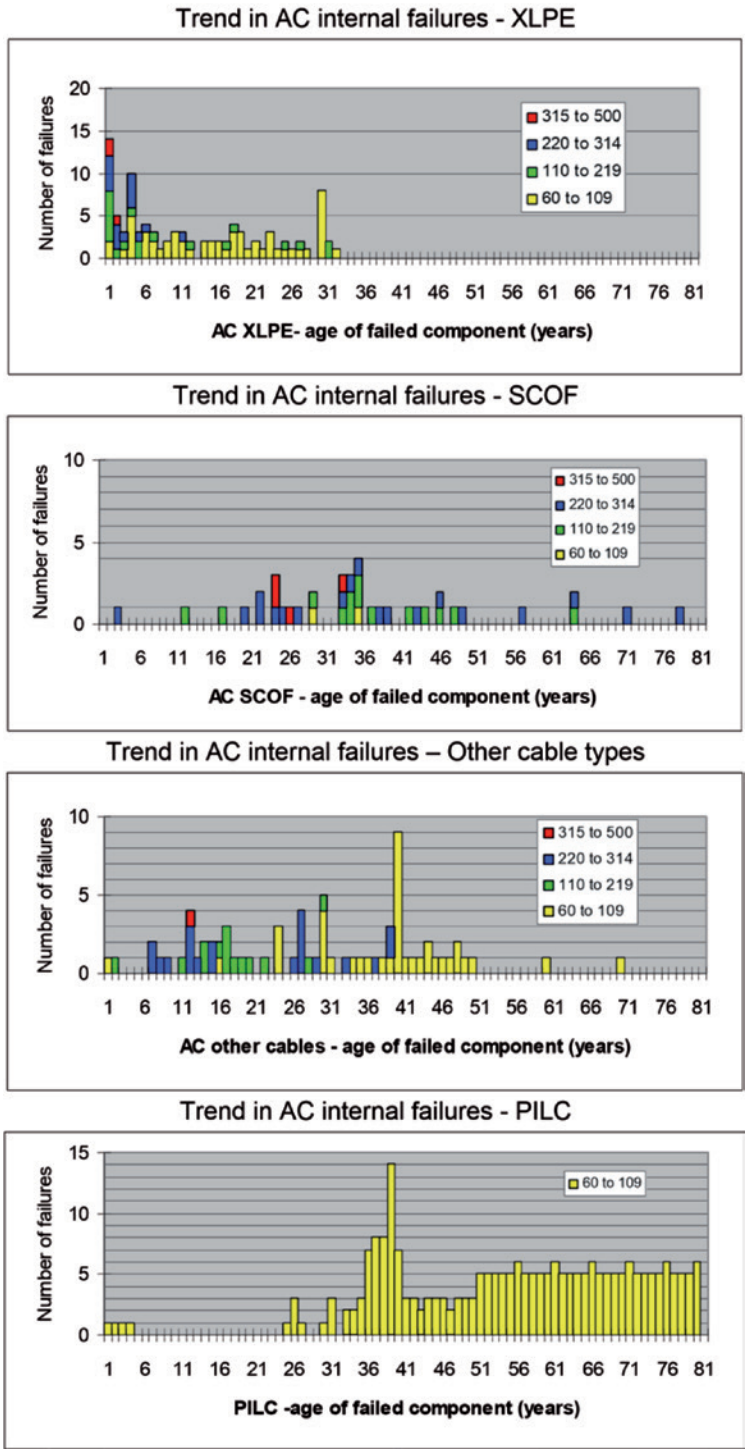

Figure C-4 | Trends in internal failures of land cables as a function of the component age [28]

Table C-2 | Failure rates of AC land accessories [28]

Voltage range kV	Cable type	Accessory tyoe	Total number of accessories in 2005	Total number of internal faults	Failure rate
60 to 219	Extruded (XLPE, PE or EPR)	Premoulded Straight joint	16995	13	0.028
		Site Made Straight joint	127711	13	0.002
		Transition joint	1336	2	0.035
		Outdoor Termination - Fluid filled - Porcelain	46226	7	0.003
		Outdoor Termination - Fluid filled - Composite insulator	2619	2	0.019
		Outdoor Termination - Dry - Porcelain	1954	2	0.024
		Outdoor Termination - Dry - Composite insulator	1353	0	0
		Outdoor Termination - Type not specified	0	6	
		Outdoor Terminations - Total	52152	17	0.007
		GIS or Transformer Termination - Fluid filled	4222	0	0
		GIS or Transformer Termination - Dry	20771	15	0.015
	SCOF	Straight joint	48843	1	0
		Stop joint	2949	4	0.028
		Transition joint	202	0	0
		Outdoor Termination Porcelain	13262	2	0.003
		Outdoor Termination Composite Insulator	22	0	0
		GIS or Transformer Termination - Fluid filled	3306	2	0.012
	HPOF	Straight joint	1359	4	0.06
		Stop joint	56	0	0
		Trifurcating Straight joint	45	0	0
		Trifurcating Stop joint	0	0	0
		Outdoor Termination Porcelain	796	0	0
		GIS or Transformer Termination - Fluid filled	38	0	0
	GC	Straight joint	1194	1	0.017
		Outdoor Termination Porcelain	380	2	0.105
		GIS or Transformer Termination	99	1	0.202
		Transition joint	41	0	0
220 to 500	Extruded (XLPE, PE or EPR)	Premoulded Straight joint	2212	4	0.044
		Site Made Straight joint	2780	2	0.015
		Transition joint	7	0	0
		Outdoor Termination - Fluid filled - Porcelain	1493	2	0.03
		Outdoor Termination - Fluid filled - Composite insulator	61	0	0
		Outdoor Termination - Dry - Porcelain	0	0	0
		Outdoor Termination - Dry - Composite insulator	53	0	0
		Outdoor Termination - Type not specified	0	13	
		Outdoor Terminations - Total	1607	15	0.215
		GIS or Transformer Termination - Fluid filled	2447	2	0.016
		GIS or Transformer Termination - Dry	637	2	0.071
	SCOF	Straight joint	13425	1	0.002
		Stop joint	1272	6	0.097
		Transition joint	13	0	0
		Outdoor Termination Porcelain	4142	5	0.024
		Outdoor Termination Composite Insulator	0	0	0
		GIS or Transformer Termination - Fluid filled	3682	1	0.005
	HPOF	Straight joint	923	1	0.022
		Stop joint	16	0	0
		Trifurcating Straight joint	38	0	0
		Trifurcating Stop joint	8	0	0
		Outdoor Termination Porcelain	244	3	0.246
		GIS or Transformer Termination - Fluid filled	109	0	0
	GC	Straight joint	0	0	0
		Outdoor Termination Porcelain	0	0	0
		GIS or Transformer Termination	0	0	0
		Transition joint	0	0	0

Annex D

Health index parameters for electrical network equipment assets

This annex provides some examples of the parameters that could be considered when calculating a health index for common electrical network equipment assets.

D.1 Transformer

Table D-1 | Parameter for health index of transformer

Parameter	Description
Age	Age of the transformer
Result of dissolved gas analysis	The index of the condition evaluation of the inside of the transformer, estimated by the amount and type of dissolved gas products measured
Polymerization degree	Deterioration index of the insulation paper evaluated by the amount of methanol, $CO+CO_2$ and furfural measured
Result of insulating oil analysis	Evaluated by acid value, tan δ, and dielectric tangent
Moisture content	Moisture content evaluation in the oil
Experience of failures of the same type of equipment	Classified by the same type of the transformer based on the incident experience. Grouped by the specification, the manufacturer, the lot number, and the year of manufacture
Occurrences of oil leakage	With or without oil leakage
Inclusion of polychlorinated biphenyl (PCB) materials	With or without PCBs
Deterioration diagnosis of the bushing	Indexed by the type and condition of the bushing
Number of actuation times of load tap changer	Indexed by the type and condition of load tap changer
Incident fault rate	Evaluated by statistical incident fault rates

D.2 Gas circuit breaker

It is often difficult to detect abnormal condition and to carry out the modality diagnosis for gas circuit breakers. Although future review and progress in this area is expected, some of the items listed in Table D-2 could constitute parameters for calculating the health index of a gas circuit breaker.

D.3 Insulated cable

As an example for soundness evaluation of insulated cables, a concept called "remaining life" is proposed, with a case study of remaining life methodology provided in CIGRE TB 358 [12]. Table D-3 introduces the approach, which could be considered similar to the calculation of a health index.

Table D-2 | Parameters for health index of gas circuit breaker

Parameter	Description
Age	Age of the circuit breaker
Diagnosis result of switching characteristics	Evaluated by the measurement result of switching time and stroke
Wear conditions	Established based on the grease lifetime and duty of the operating mechanism area (with or without multi-frequency switching duty)
Airtightness	Established based on the material of O-ring and the sealing performance (gas leakage risk) due to flange structure
Experience of failures of the same type of equipment	Classified by the same type of the circuit breaker based on the statistical experience. Grouped by the specification, the manufacturer, the lot number, and the year of manufacture
Grease deterioration	Grease deterioration (grease solidification and sliding performance)

Table D-3 | Questions for estimating remaining life of insulated cables [12]

Question	Description	Possible answer	Answer
	Technical questions		
T1	Is the failure rate of the cable under consideration increasing significantly?	N=0; Y=6	
T2	Is only the failure rate of the reference cable increasing significantly?	N=0; Y=2	
T3	Is the failure rate of the accessories under consideration increasing significantly?	N=0; Y=3	
T4	Is only the failure rate of the reference accessories increasing significantly?	N=0; Y=1	
T5	Is the age of the system between 40 to 60 years?	N=0; Y=1	
T6	Is the system older than 60 years?	N=0; Y=2	
T7	Is there regular fluid/gas leakage along the link?	N=0; Y=2	
T8	Is the sheath integrity doubtful?	N=0; Y=2	
T9	Is the cable thermally highly loaded or overloaded?	N=0; Y=1	
T10	Is there an increased risk of corrosion for this link?	N=0; Y=1	
T11	For solid insulated cables only: is the cable system without water barriers and in a wet environment?	N=0; Y=1	
T12	Is the cable subjected to large mechanical forces or vibrations?	N=0; Y=1	
	Total technical score: **T = (T1 + T2 + ... + T12) / N, where N is the maximum score of the applicable questions for the cable type**	0 < T < 1	
	Economic questions		
E1	Make a life cycle cost comparison of the cable under consideration versus a new cable. Is replacement of the cable the best economical option?	N=0; Y=1	
	Alternative economic questions		
E2	Are the operating and preventive maintenance costs of the cable system unacceptably high?	N=0; Y=2	
E3	Are the costs of not delivering power unacceptably high?	N=0; Y=2	
E4	Is there an economic window of opportunity to enhance the circuit?	N=0; Y=1	
E5	Are the costs of a repair unacceptably high?	N=0; Y=2	
	Total economic score: **E = E1, or (E2 + E3 + E4 + E5) / 7**	0 < E < 1	
	Strategic questions		
S1	Is there a significant risk of unsafe situations?	N=0; Y=4	
S2	Is there an environmental risk, which disables the use of the cable system under consideration?	N=0; Y=2	
S3	Is the circuit critical in the network?	N=0; Y=1	
S4	Is the cable type no longer maintainable and properly repairable?	N=0; Y=1	
S5	Is the total time to locate and repair a circuit unacceptable?	N=0; Y=1	
S6	Is the cable, joint and termination design no longer appropriate for its operating conditions?	N=0; Y=1	
S7	Is there a window of political opportunity to spend money on this circuit?	N=0; Y=1	
	Total strategic score: **S = (S1 + S2 + ... + S7) / 11**	0 < S < 1	
	Weighting factors		
	Technical, a	1 < a < 5	
	Economic, b	1 < b < 5	
	Strategic, c	1 < c < 5	
	Total overall score: **X = (a.T + b.E + c.S) / (a + b + c)**		

Score	Recommended action
X > 0,4	Red: the system is approaching its end of life – Act directly to change the red to orange or green by simple means (e.g. change the accessories only, mitigate a safety issue, solving technical problem - see Chapter 7) – If there is nothing that can be done, change the complete cable system starting with the cable system that scores highest
0,1 < X < 0,4	Orange: the system needs particular attention – Find out what can be done to change the orange to green – Collect data on this power cable, and perform adequate maintenance – Repeat the **detailed** approach after 1-3 years, after a corrective maintenance action, and in case of a major change in the cable operation/performance/installation
X <= 0,1	Green: the system does not need immediate actions – Carry on collecting data on this power cable – Repeat the **simplified** approach after 3-5 years and in case of a major change in the cable operation/performance/installation

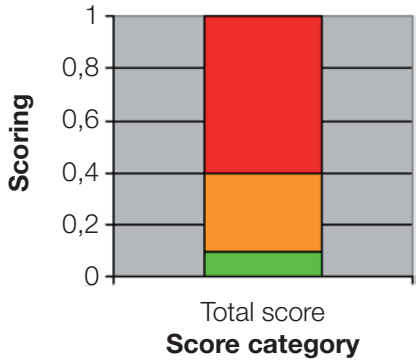

Figure D-1 | Scoring for the questions and the score category [12]

D.4 Overhead line

Table D-4 | Parameters for calculating health index of an overhead line

Facility	Item	Description
Steel tower	Age	Age of the steel tower
	Deterioration degree (visual test)	Deterioration degree of the whole steel tower including the corrosion degree of each component evaluated by visual test
	Galvanizing thickness	Residual galvanizing thickness obtained with the thickness gauge
	Reliability degree	Design strength risk by means of back check of withstanding strength based on the latest knowledge Risk of strength of the steel tower decreased by corrosion
Electric wire	Age	Age of the wire
	Residual cross sectional area	Residual cross sectional area of the steel core and the aluminium wire
	Residual tensile strength	The tensile strength of the strand wire at the diagnosis estimated by the cross sectional area or directly obtained
	Heat generation	With or without heat generation of the compression joint tube

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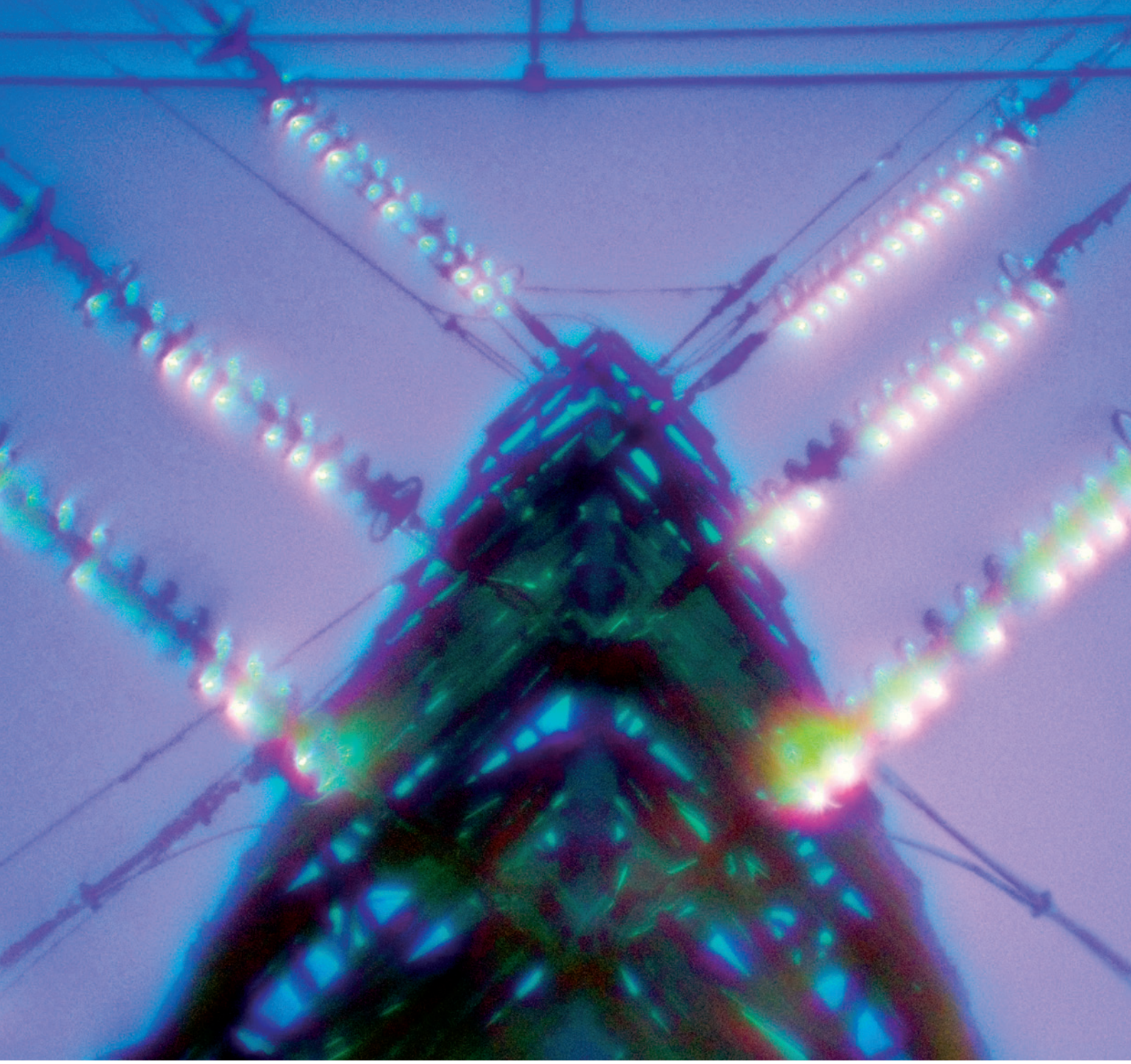

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International
Electrotechnical
Commission ®

3 rue de Varembé
PO Box 131
CH-1211 Geneva 20
Switzerland

T +41 22 919 02 11
info@iec.ch
www.iec.ch

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