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Good Practice Guide for the Risk Management of Planned Long Duration Outages

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1. Introduction

Distribution Network Operators (DNOs) have a Distribution licence obligation to plan and develop their systems in accordance with Engineering Recommendation (ERec) P2/6, the system planning standard applicable to security of supply.

The detailed risk analysis that underpins ERec P2/6 contain assumptions relating to system outages, and implicitly considers relatively short term outages for system maintenance rather than longer term outages associated with system extension or major asset replacement works. Given the escalating activity associated with asset replacement across Great Britain, consideration of issues associated with Planned Long Duration Outages (deemed to pose a higher risk to customer's supplies and typically associated with major construction works) has become increasingly important.

In 2007, Ofgem commissioned KEMA Limited to examine the case for a review of the current distribution system design criteria in Great Britain[1]. A key recommendation arising from this report was that further work was required to develop guidance relating to quantifying the system security risks associated with Planned Long Duration Outages and the associated cost of risk mitigation.

In order to make informed decisions on how to appropriately manage and implement Planned Long Duration Outages, there is a clear need to undertake risk assessment exercises. Depending on the level of confidence in the risk assessment process and the associated risk decision thresholds, risk mitigation strategies may vary between projects and over time.

As ERec P2/6 does not explicitly address Planned Long Duration Outages such as those associated with major construction works, there is a requirement to understand and quantify the risk to customer supplies that are associated with varying outage management practices. Account may be taken of the cost of alternative strategies for mitigating risks so that appropriate decisions can be made in relation to contingency arrangements.

This ERec complements the planning standards set out in ERec P2/6 and provides a framework for appropriate outage risk management from which local procedures can be developed, whilst giving consideration to managing relationships with customers and the wider community. The document has been developed by utilising industry experience relating to good practice in outage planning within DNOs.

The document is in two parts. Part 1 provides guidance on the factors to be considered during a typical outage planning process and Part 2 relates to the risk assessment method that could be applied during the process.

This is the first Good Practice Guide and it is proposed to review the application of the Guide and any learning points approximately 18 months to 24 months after its introduction. The need for any updates will be identified.

2. Purpose

The purpose of this ERec is to provide a good practice guide for the application of outage risk management techniques when applied to Planned Long Duration Outages (PLDOs) to enable informed outage planning decisions to be made.

It aims to provide guidance on the management of Planned Outages, across the life cycle of a Planned Outage, to ensure an appropriate balance between standards of service to

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[1] Final Report: Review of Distribution Network Design and Performance Criteria, G06-1646, Rev 003, 19 July 2007.

customers and cost. This decision making process often requires a trade-off between the savings associated with avoiding contingency arrangements relative to the costs associated with unplanned customer interruptions whilst taking into account the likelihood of such an event.

A further objective of this ERec is to offer guidance relating to other considerations that may affect the outage planning decision making process, taking into account areas such as customer perception and the management of relationships with the wider community including Ofgem, the Government and the media. It also aims to facilitate the Planned Outage coordination and management of interfaces between National Grid, DNOs, Customers and Independent DNOs (IDNOs).

The techniques in this document are considered to represent good practice management of risks associated with Planned Long Duration Outages. However they are not prescriptive and as such DNOs may choose to adopt alternative approaches to both the assessment of risk and the evaluation of benefits associated with various controls and mitigations.

The examples given are not meant to represent any particular outage condition but to provide sufficient guidance for all circumstances. As such, under more common outage conditions, it is unlikely that all the actions will be necessary.

The principles are not expected to increase the costs associated with an outage but to provide an example mechanism whereby good practice could be recorded. In most cases, it is likely that existing practices and processes within the individual DNOs, already satisfy these principles.

This document will not impose additional duties on any third party across a responsibility boundary including National Grid other DNOs or IDNOs etc.

3. Scope

The scope of this ERec document applies to DNO PLDOs, affecting demand groups Class C, Class D and Class E as defined in ERec P2/6 (see Appendix 1). However, the underlying principles and guidance described in this document may also be applied to shorter duration outages or demand groups affecting Class A or B.

The recommendations apply during the planning and execution phases of a Planned Outage where there is judged to be a material increase in system security risk during the Planned Outage, and/or where the profile of system security risk can be influenced by the application of varying outage management practices. Routine maintenance activities are not normally considered to materially increase system security risk. Where a DNO considers it appropriate, they may wish to exclude all routine maintenance activities from their definition of a PLDO.

It does not specifically provide outage planning guidance for National Grid or IDNOs but does include the requirement for Planned Outage coordination between key stakeholders, including Network Operators.

It does not provide guidance on how to take into consideration Distributed Generation (DG) within Planned Outage risk mitigation or contingency plans although DG contribution should be considered by DNOs in their normal management of networks to ensure compliance with P2/6. In view of the increasing importance of DG this issue will be considered again at the first document review to establish if additional guidance is necessary.

4. Definitions

The following are definitions of outage terms applicable to this ERec:

Outage Definitions	
Term	**Definition**
Distribution System	The System consisting (wholly or mainly) of electric lines owned or operated by the Distribution Network Operator (DNO) and used for the distribution of electricity between the Grid Supply Points or Generation Sets or other Entry Points to the points of delivery to Customers or Authorised Electricity Operators.
Outage	The removal from service of one or more components of the Distribution System.
Planned Outage	An Outage that is pre-arranged with sufficient notice for the outage planning process to be properly implemented. Typically this involves the removal from service, for the purpose of inspection, maintenance, repair, replacement or reinforcement, of one or more components of the Distribution System.
Unplanned Outage	An Outage that arises from a system fault or incident.
Planned Long Duration Outage (PLDO)	A Planned Outage that satisfies one or more of the following conditions: • Is longer in duration than five working days (i.e. those longer than a ‘typical’ Outage for maintenance); or • Is necessitated by major constructions works, including asset replacement or refurbishment of major equipment, particularly where the work introduces additional risks to remaining circuits or infeeds; or • In the event of a subsequent Unplanned Outage the Customer Restoration Time may be excessive (typically greater than 18 hours, in-line with Ofgem Electricity Guaranteed Standard (EGS) 2a).
Outage Duration	The period for which a Planned Outage is requested and, during which, plant, circuits or ancillary equipment will not be available for service. This period may change over the life of the planned works to take into account delays incurred or planned to be incurred causing deviation from the originally requested baseline Outage Duration.
Customer Restoration Time (CRT)	The time taken to restore customers affected by an Unplanned Outage by the quickest means possible. (for example, deploying mobile generation plant).
Return To Service (RTS)	The time required to fully re-commission plant, circuits or equipment that is the subject of a Planned Outage or an Unplanned Outage.
Emergency Return To Service (ERTS)	The time required to re-commission plant, circuits or equipment that is the subject of a Planned Outage or an Unplanned Outage sufficiently to enable the plant to be brought into a serviceable state. This does not preclude the return to service in a partially commissioned or partially serviceable state providing that the integrity of the Distribution System is not unduly compromised.
Demand at Risk	The maximum forecast demand of a section of the Distribution System expected to occur during a Planned Outage.
Transfer Capacity	The capacity of an adjacent network that can be made available within the times stated for the First and Second Circuit Outages in Table 1 of ERec P2/6. Transfer Capacity will be limited by circuit capacity or other practical limitations on power flow associated with the Outages in question.
Common Mode Failure (CMF)	Where a single event on the Distribution System causes multiple components or items of equipment within that system to fail simultaneously.

The following are definitions of risk terms applicable to this ERec:

Risk Definitions	
Term	**Definition**
Risk	An event occurring at any stage within an outage with a defined frequency and set of outcomes.
Risk Level	The magnitude of a risk expressed in terms of the combination of frequency and impact.
Event	The occurrence or change of a particular set of circumstances.
Frequency	The chance that an event happens expressed against a defined timescale.
Probability	The chance that an event happens expressed over a non time dependent scale (e.g. over a particular phase of an outage project).
Impact	The outcome(s) of an event in terms of the effect on relevant business performance parameters related to the outage.
Tolerable	The level of risk that a particular stakeholder is prepared to bear in order to achieve their objectives.
Acceptable	The level of risk that a particular stakeholder is prepared to accept with no requirement to pursue further risk controls.
Risk Control	A measure to modify risk. In this context any action to limit or reduce the frequency or probability of an event.
Risk Mitigation	Measures taken to reduce an undesired consequence.
Practical	Control and mitigation measures that are considered to be practically achievable within current knowledge and technology considering the environment of the outage.
Practicable	Control and mitigation measures that are justified by a suitable benefit to cost ratio.
Reasonable	Control and mitigation measures that are considered reasonable to implement by the business irrespective of the benefit to cost ratio.
Risk Owner	Person with the accountability and authority for understanding and managing the risk and associated risk controls and mitigations.

Part 1 – Outage Planning Process

5. Outage Life Cycle

- **Links to Part 2: Planned Outage Risk Assessment Method:**
  - *Section 7.3....... Risk Method Principles*
  - *Section 8.0....... Risk Assessment Method*
  - *Section 8.6....... Step 6: Use of Risk Information*
  - *Section 8.7....... Step 7: Iterative Application*

For any particular project (planned works), there are a number of discrete phases involved in the outage life cycle process, with the typical phases shown in Figure 1. The complexity and number of phases may vary, as determined by organisational structures, processes and procedures. For the majority of routine maintenance outages, it may be feasible to omit some of the stages discussed below. Although reference is made to various 'construction' phases in the life cycle process, the process may be applied to larger scale maintenance projects where appropriate.

At an early stage, the outage feasibility would be considered. As the project planning becomes more detailed, this moves to outage assessment and then to the outage approval stage. The final phases include the outage execution and outage appraisal phases.

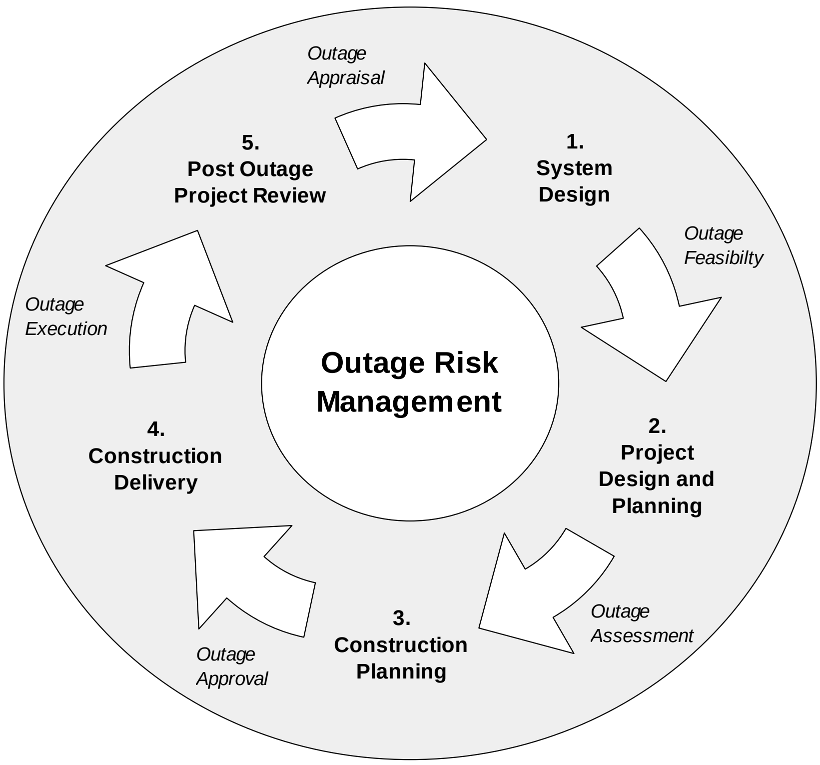


Figure 1 – Planned Outage Life Cycle

The detail to be considered and the time needed to complete each phase may vary from project to project depending upon the complexity of the system and the outages required.

Risk assessment techniques would be employed throughout the outage life cycle to determine the system security risk posed by the outage. This would aid the decision making processes relating to the application of potential risk control or mitigation techniques.

5.1. System Design Phase (Outage Feasibility)

At the initial phase in the outage life cycle process, the feasibility of taking an outage needs to be considered. This high level planning would typically consider generic information such as outage coordination, planned duration, time of year, restoration time, the extent and nature of the Demand at Risk and the associated potential risk to customer supplies in the event of an associated, Unplanned Outage. Potential contingency plans and associated costs should be identified. These factors would be taken into account ahead of any further detailed planning. In addition, a continual review of these factors throughout the outage life cycle provides the opportunity to review and if necessary redesign the project to reduce the risk to within acceptable limits. The outage feasibility is likely to be reviewed periodically during the outage life cycle but the opportunities to redesign the project are progressively reduced as the project develops.

5.2. Project Design and Planning Phase (Outage Assessment)

As a project evolves, there is a need to assess the outage requirements in more detail to enable the risks to be quantified more accurately. At this phase, details of the main equipment required under the outage along with more accurate duration and restoration times would be available. Outages would typically be agreed in principle and suitable provision made within coordinated outage plans. Consideration may also be given to developing draft contingency plans.

5.3. Construction Planning Phase (Outage Approval)

During this phase, detailed outage planning would take place with a view to gaining outage approval. A formal outage request may be completed by the requester, specifying all necessary outage information such as dates of the outage, duration and nature of the works being undertaken. Detailed consideration may be given to all the tasks necessary to approve the outage, the tasks required during the outage and the steps to be taken to close out the outage (under both normal and abnormal conditions). Initial pre-outage checks may be completed as appropriate and contingency plans produced in detail during this phase.

5.4. Construction Delivery Phase (Outage Execution)

The outage execution phase would require the operational team undertaking the outage to complete all necessary pre-outage checks and to comply with all constraints or contingency requirements, including taking all appropriate steps to ensure the site works are being completed in an expedient manner in line with the project delivery plan. During the implementation of the project works, progress may be routinely reviewed and any necessary alterations made to the outage plans such as contingency arrangements, updating of restoration times, or modification during outage checks.

5.5. Post Outage Project Review Phase (Outage Appraisal)

The final phase would give consideration to a post outage appraisal in order to identify any learning points and assist in the development of any future guidance. Consideration may be given to a holistic view of the effectiveness of the end to end outage life cycle process including a review of:

- The associated pre, during and post outage activities, including contingency plans.
- The original project proposal to determine whether it was the most appropriate solution in view of any issues arising from the overall outage planning activity.

In addition, consideration should be given to compiling a lessons learned log including any learning that could improve future network designs.

6. Outage Planning Considerations

This section describes the factors to be considered throughout the outage life cycle in order to make informed outage planning decisions.

Planned Outages shall be planned in accordance with the requirements of the Grid Code and Distribution Code. In addition, during Planned Outages, all statutory requirements must be maintained including requirements to safeguard the safety of the public and Network Operator staff.

6.1. Outage Coordination

Planned outages on the Distribution System should be coordinated in an efficient, economical and optimised manner so as to manage any impact on the performance of the Distribution System. Coordination of outages could consider the following;

- DNOs own Planned Outage requirements associated with maintenance, repairs and construction projects.
- National Grid.
- Other DNOs.
- IDNOs.
- Customer service.
- Generators.

Planned Outage requirements should be of sufficient detail (through exchange of information between relevant stakeholders) to satisfy the operational planning requirements of the Grid Code and the Distribution Code.

Consideration should also be given to managing Planned Outage coordination for third party access to the Distribution System. Typical access requirements may include:

- Proximity outages for work on plant, circuits or equipment near live overhead lines.
- Earth wire work associated with fibre optic links.
- Tower access for installation/work on cellular phone aerials.
- Requirement to temporarily or permanently move components of the Distribution System to accommodate roads and buildings.

Consideration may be given to the consequences of not approving the Planned Outage and the impact this may have.

The effectiveness of coordination arrangements will be assessed whenever the document or its practical implementation is reviewed.

6.2. Planned Outage Duration

- **Links to Part 2: Planned Outage Risk Assessment Method:**
  - *Section 8.2....... Step 2: Likelihood Evaluation*

Information should be collated relating to the proposed duration of the Planned Outage that is necessary to enable the planned works to be carried out. This request would include specific Planned Outage dates.

6.3. Nature of Works

- **Links to Part 2: Planned Outage Risk Assessment Method:**
  - *Section 8.2....... Step 2: Likelihood Evaluation*

A clear understanding should be established of the nature of the works proposed and the impact this may have on system security risk for the duration of the Planned Outage. Information may be gathered relating to:

- *Classification of the nature of the works* (e.g. maintenance, construction etc).
- *Classification of the type of assets subject to the Planned Outage* (e.g. overhead lines, transformers, switchgear etc).
- *Details of the physical work proposed* (description of each stage of the proposed work and related project and construction complexity).

The information gathered allows an initial assessment of system risk exposure arising from the Planned Outage, for example:

- For major construction works, large numbers of customers could be at risk of extended duration supply loss unless comprehensive contingency measures are established for emergency restorations.
- Protection work may require a relatively short Outage Duration, but may increase the likelihood of accidental interruption of those circuits that remain in commission.
- The nature of the works may introduce the Risk of Trip (ROT) where there is the potential of inadvertent operation of specified switchgear, therefore placing customers at risk. There may be instances (e.g. single transformer substations) where ROT may not be acceptable.
- Overhead line repairs may enable fast restoration in the event of an Unplanned Outage, whereas underground cables may have a longer restoration time, but are less likely to fault.

6.4. Asset Integrity and System Performance

- **Links to Part 2: Planned Outage Risk Assessment Method:**
  - *Section 8.2....... Step 2: Likelihood Evaluation*

Consideration may be given to any known asset integrity or system performance issues relating to plant, circuits and associated equipment which remain in service for the duration of the Planned Outage and which support supplies normally carried by the plant, circuits or equipment out of service. Factors that may increase system security risk for the duration of the Planned Outage could be identified, for example:

- Circuits or equipment with known high fault rates.
- Equipment with inherent design or specification issues that adversely affect its performance.
- Location of equipment that may adversely affect its performance, e.g. overhead lines in wooded areas or on high ground, exposure to pollution, subjected to third party interference or located in a high vandalism area.
- The age and/or condition of the relevant plant assets.
- The loading of the relevant plant assets as a result of the Planned Outage.

Reference may be made to outage checks detailed in Appendix 2.

6.5. Assessment of Restoration Time

- **Links to Part 2: Planned Outage Risk Assessment Method:**
  - *Section 8.3....... Step 3: Impact Evaluation*

Consideration should be given to an assessment of the following restoration times (as defined in Section 4):

- Return To Service (RTS) time.
- Emergency Return To Service (ERTS) time.
- Customer Restoration Time (CRT).

Profiling these times for the duration of the Planned Outage should be considered. A short CRT is likely to be required at times of high demand and/or where there are a large number of customers affected. This enables contingency arrangements to be better matched to periods of high risk. If the duration of a Planned Outage is extended as a consequence of achieving a reduced CRT then the probability of demand loss needs to be balanced against the shorter CRT.

When potentially difficult or complex Planned Outages are being considered, then methods of working could be taken into account in the early phases of the outage life cycle in order to achieve a reduced CRT.

Similarly, the time of year may be taken into account since this has a potential adverse impact on restoration times. Severe weather (typically during winter months) significantly increases the likelihood of an Unplanned Outage and can materially affect the restoration times.

6.6. Time of Year and System Loading

- **Links to Part 2: Planned Outage Risk Assessment Method:**
  - *Section 8.2....... Step 2: Likelihood Evaluation*
  - *Section 8.3....... Step 3: Impact Evaluation*

The time of year during which the Planned Outage is executed, system loading (Demand at Risk) and voltage regulation should be considered during the outage planning process. Generally it is recognised that increased system loading, and the greater impact on customers of interruption in supply, may cause additional constraints to be imposed on outage planning for the Distribution System during winter months. However, summer loading can be as high as winter and these situations may also require a thorough outage assessment. Care should be taken to ensure that customers continue to receive a supply within statutory voltage limits.

Information relating to group demands and available Transfer Capacity should be considered. Demand

Daylight Saving Time (seasonal clock change) and discrete times of the year (such as public holidays, weekends etc) may also be considered when determining the feasibility of a Planned Outage and the impact these factors may have on system loading, contingency plans and restorations times.

All plant, circuits and equipment should be maintained within the specified rating of the equipment which may include continuous, cyclic, emergency and short time ratings.

6.7. System Running Arrangements

When planning an Outage, consideration should be given to the Distribution System running arrangements. During emergency restoration conditions it is usually possible to increase the number of customers transferred to adjacent demand groups by utilising abnormal running arrangements. The following factors may be taken into account:

- Identify if there are any critical circuits that need to be in service (other than the main alternative) for the Planned Outage to proceed.
- The impact of any system abnormalities present, e.g. abnormal open points, unrepaired faults, temporary repairs, abnormal circuit configurations, construction work or consideration of possible critical latent defects.
- For systems that are operated abnormally under high load conditions, for instance to support a remote substation during a construction outage, account should be taken of voltage levels so that they are not driven outside tolerable limits for extended periods.
- Operational constraints (e.g. operational restrictions) that may affect how the Planned Outage is executed.
- The potential affect on fault level issues and the subsequent impact, e.g. generally fault levels reduce in a depleted system which can bring protection coordination issues and possibly power quality issues.

6.8. Common Mode Failures

- **Links to Part 2: Planned Outage Risk Assessment Method:**
  - *Section 8.3....... Step 3: Impact Evaluation*

Consideration may be given to the impact of any known, foreseeable Common Mode Failures (CMF) that may result in the loss of plant, circuits or equipment that is used to maintain supplies to customers for the duration of the Planned Outage. For example:

- Dual circuits feeding a primary substation.
- Overhead line circuits on the same route.
- Double circuit tower overhead line routes (e.g. dual circuit failure due to extreme weather).

- Multiple cables on cable bridges, in tunnels and subject to third party damage.
- Multiple cables in the same trench and subject to third party damage.
- Multiple cable damage from land subsidence.
- Absence of blast / fire walls or adequate distance between circuit breakers.

Knowledge of such CMFs may not always result in any mitigating action since the cost of risk mitigation may be grossly disproportionate to the risk posed by the CMF.

6.9. Customer Service

It may be appropriate to give consideration to certain categories of customers in order to effectively manage customer service and media liaison issues in the event of an Unplanned Outage. This may improve the communications with, and management of, sensitive customer groups. From an assessment of such customer groups, it can be determined what actions may be appropriate for a particular Planned Outage. For example, a suitable action may be to discuss the outage with the owners of any critical infrastructure or services that could be affected, prepare media communication plans or customer service contingency plans.

6.10. Contingency Plans / Post Fault Management

- **Links to Part 2: Planned Outage Risk Assessment Method:**
  - *Section 8.4....... Step 4: Risk Prioritisation and Valuing Risk Change*
  - *Section 8.5....... Step 5: Risk Management*

Consideration should be given to preparing documented contingency plans. The level of detail contained within the plan should be commensurate with the risk level to which customers and / or the system is exposed. A typical plan may include:

- General details of the Planned Outage.
- A risk profile of the individual tasks being undertaken during the outage. This could include the restoration profile in terms of customer restorations under a range of scenarios e.g. fault at night, system peak etc.
- The actions necessary in the event of an Unplanned Outage (i.e. the steps that need to be taken to restore supplies) for each critical and foreseeable fault condition.
- Identity and contact details of those personnel responsible for undertaking the actions.
- Supporting information (i.e. resource requirements, post fault restoration switching schedules, generator deployment plan, equipment and materials required and their location etc).

An example contingency plan is shown in Appendix 2. In preparing contingency plans, consideration should be given to associated group demands and available transfer capacity, including the:

- Ability to pick up load via remote and/or manual switching.
- Ability to utilise Secondary Distribution circuits (High Voltage interconnection).
- Ability to utilise demand reduction.

Potential post fault overloading should be managed safely, considering relief by voltage reduction or disconnection. Disconnection may include voluntary demand reduction (for customers with higher demands).

6.11. Outage Checks

- **Links to Part 2: Planned Outage Risk Assessment Method:**
  - *Section 8.5....... Step 5: Risk Management*

Consideration may be given to pre, during and post Planned Outage checks as deemed appropriate to manage system security risk. Checks can be broadly summarised in three stages:

- *Pre outage checks* - apply to the plant, circuits and associated equipment which remain in service and are used to maintain supplies to customers.
- *During outage checks* - as pre outage checks, in addition to plant, circuits and associated equipment out of service (where applicable).
- *Post outage checks* – apply to plant, circuits and associated equipment that have been out of service during the Planned Outage.

Consideration may be given to the typical checks applicable to each element of the Distribution System as detailed in Appendix 3. Actual checks, and the frequency at which they could be undertaken, should be determined by individual circumstances, including the level of risk and the quality of data already available.

6.12. Risk Control and Risk Mitigation Strategies

- **Links to Part 2: Planned Outage Risk Assessment:**
  - *Section 8.4....... Step 4: Risk Prioritisation and Valuing Risk Change*
  - *Section 8.5....... Step 5: Risk Management*

For Planned Outages that may have a significant impact on customers (as measured by the number of customers affected or the time off supply) it may be appropriate to develop suitable risk control or mitigation strategies for a particular Planned Outage. These strategies should be appropriate to the risk level to which customers are exposed.

The strategies may involve assessing whether the works can be undertaken in a different way to minimise the risk, albeit at a higher cost, or installing the new equipment off line. Alternatively the mitigation plan may involve a more reactive approach by considering ways to improve the restoration time (for example by identifying necessary resources in advance of executing the Planned Outage).

6.13. Reliability and Availability

- **Links to Part 2: Planned Outage Risk Assessment:**
  - *Section 8.3....... Step 3: Impact Evaluation*

An assessment should be made of the impact of a subsequent Unplanned Outage, taking into account:

- An assessment of the number of customers that would be subject to a supply interruption and the length of the interruption.

- A calculation of quality of service impact (utilising Customer Interruptions (CI) and Customer Minutes Lost (CML) measures). This may include an assessment of the likely Information and Incentives Scheme (IIS) impact.
- An assessment of the potential impact upon relevant Electricity Guaranteed Standards (EGS) payments.

Part 2 – Planned Outage Risk Assessment Method

7. Risk Assessment and Outage Approval Process Overview

Part 2 provides an overview and high level guidance on the principles that should be considered in the development and operation of a risk assessment method for the evaluation and management of PLDOs.

Further detailed guidance relating to the risk assessment process and application is discussed in Appendix 4.

Appendix 5 (High Level Risk Assessment Process) and Appendix 6 (Risk Method) may assist DNOs in the development of a suitable process.

7.1. Risk Terminology

The following risk terminology is applied in the context of PLDO risk assessment:

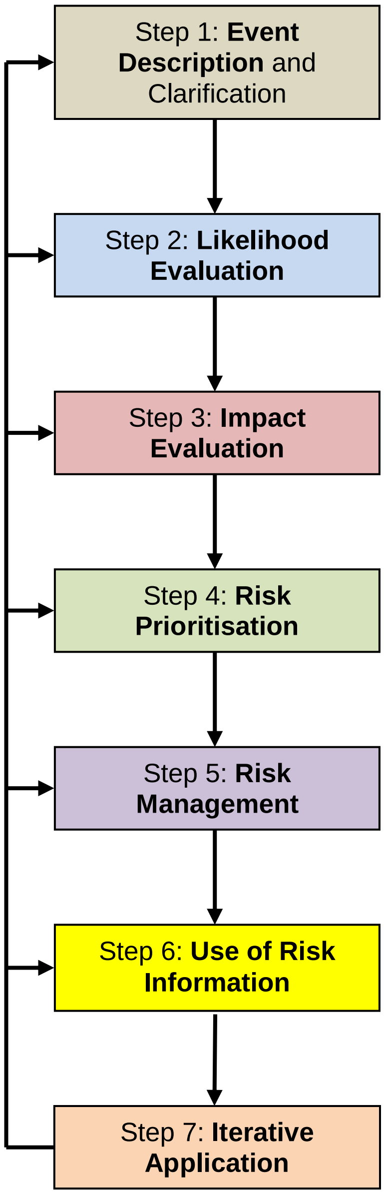
- An **event** is something that happens or a set of circumstances that gives rise to a **risk**.
- A **risk** is how the **event** is realised in practice within the particular project and environment. A risk has a particular **likelihood** (expressed as **frequency** or **probability**) together with a particular set of one or more **impacts**.
- **Risk** significance is measured through consideration of the **frequency** or **probability** together with the **impacts**.
- Risk prioritisation thresholds can be applied to:
  - An individual **impact**, or to **impacts** in combination.
  - An **expectation value** of risk (the product of **frequency** or **probability** with one or more **impacts**; typically expressed as a value (money) over the project, or as an annualised value (money per year).
- **Risk controls** act so as to limit or reduce the **likelihood** of the event occurring.
- **Risk mitigations** act so as to limit or reduce the scale of **impact** should the **event** occur.

7.2. Risk Assessment Method Summary

The risk method should be structured, systematic and will need to allow for the risk varying through the outage period.

In many cases the highest risks will be relevant only for relatively short periods, perhaps where particular activities are taking place, or where the work requires a particular network configuration.

Due to the nature of works being undertaken, PLDOs will affect the risk (both likelihood and impact) of large numbers of customers losing supply for extended periods. In order to adequately assess and respond to this risk, it is necessary to establish a practical risk assessment method that is consistent with the DNO’s business structure, performance and needs. Such a method is summarised in seven steps below.



1. The **Event Description** describes what will happen and the way in which the risk will be realised. Typically, the event description will detail how the primary alternative supply could be lost. The risk arising from the event is then evaluated in terms of the likelihood and the impact (i.e. how the network will respond to the event),
2. **Likelihood Evaluation** is the probability of the event occurring over the course of the project or project stage and is typically evaluated using industry failure rate data.
3. **Impact Evaluation** describes what will happen if the event were to occur. Typically this will be defined by two specific parameters, Customer Interruptions and Restoration Time.
4. **Risk Prioritisation** evaluates the risk level and significance to the DNO. This will inform the need for risk management and will also identify the appropriate level in the organisation for communication and/or acceptance of a risk level relating to the PLDO.
5. **Risk Management** considers the available control and mitigation options in terms of benefit and cost to determine the optimum risk management strategy. This includes consideration of the both the Practicality and Practicability of the options individually and in combination. The optimum solution will depend upon the tolerability and acceptability of the risk to the particular DNO (and other stakeholders).
6. **Use of Risk Information** from the preceding stages will have a number of applications within the particular DNO. As such, it will need to be documented and circulated as appropriate.
7. **Iterative Application** is successive application of the risk method either to compare various control and mitigation options or to re-assess the risk as a project evolves through the life cycle.

During the application of this risk method, DNOs should note their assumptions for each of the seven steps in the process.

An essential feature of outage planning is that the risk will vary considerably through the project. In many cases the highest risk will be relevant only for a relatively short period, perhaps where particular activities are taking place, or where the work requires a particular network configuration. Thus, for perceived high risk PLDOs, the process should be initiated as early as possible in the Planned Outage life cycle. The risk assessment should then be reviewed and updated during the Planned Outage life cycle as additional or more accurate information becomes available.

The risk method is designed to be simple and resource effective in its application. It is intended to reflect the dynamic nature of risk through the project.

The guidance does not specify risk ownership, or the stages at which the method should be applied. Implementation by individual DNOs will require integration with their overall project management arrangements.

To aid understanding a practical example of a typical planned outage for a hypothetical DNO is shown in Appendix 7. The example is illustrative only and is not intended to be taken as a definitive template for application of this ERec.

7.3. Risk Method Principles

- **Links from Part 1: Outage Planning Process:**
  - *Section 5.......... Outage Life Cycle*

The following are a set of risk principles that should be applied in development and implementation of a risk method by DNOs. The risk process should be:

- Systematic, consistent, structured and operate under a common language.
- Ensure that likelihood evaluations match the assigned impacts.
- Based on the best information available at realistic cost.
- Part of Planned Outage planning at each stage of the Planned Outage life cycle.
- Transparent and understandable by practitioners and managers.

8. Risk Assessment Method

The following sections provide brief clarification of the seven risk process steps as defined in Section 7.2 above.

8.1. Step 1: Event Description and Clarification

The first stage of the method is to define the event and to clarify the event being evaluated. As a general guide the event is likely to be:

'Circumstances resulting in an unplanned outage on a circuit upon which supplies are reliant whilst the alternative circuit is not available due to planned project works'

Assigning the likelihood and impact against each identified event will provide the basic position for recording and evaluating measures to manage the risk.

8.2. Step 2: Likelihood Evaluation

- **Links from Part 1: Outage Planning Process:**
  - *Section 5.......... Outage Life Cycle*
  - *Section 6.2....... Planned Outage Duration*
  - *Section 6.3....... Nature of Works*
  - *Section 6.4....... Asset Integrity and System Performance*
  - *Section 6.6....... Time of Year and System Loading*

Likelihood is defined as:

"The probability that the event occurs over the course of the project or project stage under consideration."

In general, event likelihood should be evaluated using industry data failure rates as a base (to the extent that this data is available). Where asset and/or DNO specific data is available and can provide an improved basis for the likelihood assessment, then this data can be used as an alternative, or to compliment the industry data failure rates.

Where no numerical asset failure rate data is available, likelihood can be based on judgement informed by suitable experience. This should use a scale to ensure consistency in likelihood estimation.

In any case the likelihood estimates may be adjusted to reflect the activities and environment of a particular PLDO.

8.3. Step 3: Impact Evaluation

- **Links from Part 1: Outage Planning Process:**
  - *Section 6.5....... Assessment of Restoration Time*
  - *Section 6.6....... Time of Year and System Loading*
  - *Section 6.8....... Common Mode Failures*
  - *Section 6.13..... Reliability and Availability*

Impact should be measured through one or more of the industry quality of service performance measures. In all cases calculation of the performance measures should be consistent with current regulatory guidance and industry good practice. The two key impact measures are:

- **Number of customers affected (Customer Interruptions):** This is the number of customers that will experience reportable loss of supply if the event were to occur.
- **Time to restore supplies:** This is the time to restore supplies to customers taking account of the circumstances, conditions and environment when the event occurs. In practice restoration of supplies may be through more than one stage.

The customer restoration profile should take account of the potential for any known multiple equipment or hardware failure (including Common Mode Failures and Cascade Failures) including the effect on repair / reinstatement requirements to restore supply.

8.4. Step 4: Risk Prioritisation and Valuing Risk Change

- **Links from Part 1: Outage Planning Process:**
  - *Section 6.10..... Contingency Plans / Post Fault Management*
  - *Section 6.12..... Risk Mitigation and Risk Control Strategies*

Risk prioritisation and valuing risk change requires that DNOs can:

- Evaluate the risk level and significance to the DNO.
- Compare and prioritise risks arising during the PLDO.
- Evaluate the value of risk control and mitigation options.
- Set thresholds of importance for risk to the DNO.
- Set thresholds at which the DNO would communicate outage planning issues internally or to regulators.

Risk value thresholds could be set and managed through:

- Setting limits for single parameters (e.g. number of customers interrupted > 100,000) and using these to determine the risk significance.
- Use of a risk matrix as a method to consider risk likelihood and impact in combination to determine risk significance.

Prioritisation of risk is may be in the form of a relatively simple traffic light system (Red/Amber/Green) based on the risk level. In any prioritisation scheme a red risk may still be acceptable. The prioritisation relates to the level at which a DNO may categorise a particular risk, the type of action that may be appropriate and typical levels of escalation within the company.

The table below provides general guidance on actions that may be appropriate to particular prioritisation levels.

Guidance on Risk Prioritisation by Category			
Risk Category	**Definition**	**Clarification/Effect**	**Typical Actions**
Red	High	• High/very high potential impact to the business. • Strong case for adoption of further risk control and/or mitigation. • Risk may be tolerated but may require senior level awareness and sign off.	• Identify and evaluate all possible additional risk controls and mitigations. • Formal note that all reasonable risk controls and mitigations are in place. Decision to proceed or take alternative course of action typically taken at director level.
Amber	Tolerable	• Significant potential impact to the business. • Evaluate further risk control and/or mitigation. • Risk tolerable subject to control to the lowest practical and practicable level.	• Identify and evaluate additional risk controls and mitigations. • Formal note that all reasonable risk controls and mitigations are in place typically endorsed by appropriate manager/director.
Green	Acceptable	• Low potential impact to the business. • Potential for additional inexpensive additional risk control and/or mitigation. • Potential for relaxation of controls/mitigations where saving is disproportionate to risk increase. • Risk acceptable to the business.	• Review to identify any additional simple and low cost risk controls and mitigations. • Review to identify potential for relaxation of proposed controls/mitigations. • Formal note that all reasonable risk controls and mitigations are in place typically endorsed by appropriate manager.

8.5. Step 5: Risk Management

- **Links from Part 1: Outage Planning Process:**
  - *Section 6.10..... Contingency Plans / Post Fault Management*
  - *Section 6.11..... Outage Checks*
  - *Section 6.12..... Risk Mitigation and Risk Control Strategies*

Risk management is the process through which:

- Risk control and mitigation options are identified. Note that **risk controls** act so as to **limit or reduce the likelihood** of the event occurring, and **risk mitigations** act so as to **limit or reduce the scale of impact** should the event occur.
- The risk reduction and cost of options individually and in combination is evaluated.
- Valuing the risk change available from the option. The change in value of the risk should be evaluated so as to estimate the benefits achievable from the option. Change in risk

considers change in likelihood and/or impact. This can be measured as a change in a single parameter or as a change in position on a risk matrix.

- Consideration may also be given to options related to pre / during / post outage checks, contingency plans and post fault management.
- Options representing best value are selected and implemented. This may require a cost / benefit assessment to be carried out. In some cases adoption or rejection of an option or options will be an obvious decision.

8.6. Step 6: Use of Risk Information

- **Links from Part 1: Outage Planning Process:**
  - *Section 5.......... Outage Life Cycle*

Application of a risk method will generate risk information. This will have a number of uses including:

- Feedback into the risk assessment method.
- Use in discussion of the risk controls and mitigations adopted.
- Building corporate memory so as to ensure consistency in the option selection process for PLDO risk management.

8.7. Step 7: Iterative Application

- **Links from Part 1: Outage Planning Process:**
  - *Section 5.......... Outage Life Cycle*

An essential feature of outage planning is that the risk could vary considerably through the project. In many cases the highest risk will be relevant only for a relatively short period, perhaps where particular activities are taking place, or where the work requires a particular network configuration.

The risk method should reflect the dynamic nature of risk throughout the project:

- Review and update of the risk assessment so as to reflect all stages in the outage life cycle.
- Identification of critical conditions or activities in the project (including changes as the project progresses through the life cycle) and use of the risk method to ensure the control and mitigation strategy remains optimised throughout the PLDO.

9. Guidance for implementation

This ERec is intended to provide a framework that DNOs can incorporate into their own Planned Outage planning policy to ensure that system security risks related to PLDOs are quantified and balanced with the associated cost of risk control and/or mitigation. The principles are not expected to increase the costs associated with a Planned Outage but to provide an example mechanism whereby good practice could be recorded.

It is anticipated that DNOs will want to adopt the principles set out in this document subject to the requirements of their own business processes and local network arrangements. In particular it is anticipated that DNOs will want to consider implementation of the risk management principles and procedures which would ensure a consistent national approach.

The examples given are not meant to represent any particular Planned Outage condition but to provide sufficient guidance for all likely circumstances. Therefore it is unlikely that all the actions will be necessary under more common Planned Outage conditions.

Appendix 1 - Extract from Engineering Recommendation P2/6

Table 1

Class of supply	Range of Group Demand	Minimum demand to be met after: First Circuit Outage	Minimum demand to be met after: Second Circuit Outage	Notes
A	Up to 1MW	In repair time: Group Demand	Nil	Where demand is supplied by a single 1000kVA transformer the "Range of Group Demand" may be extended to cover the overload capacity of that transformer.
B	Over 1MW and up to 12MW	(a) Within 3 hours: Group Demand minus 1MW (b) In repair time: Group Demand	Nil	
C	Over 12MW and up to 60MW	(a) Within 15 minutes: Smaller of (Group Demand minus 12MW); and 2/3 of Group Demand (b) Within 3 hours: Group Demand	Nil	Group Demand will be normally supplied by at least two normally closed Circuits or by one Circuit with supervisory or automatic switching of alternative Circuits.
D	Over 60MW and up to 300MW	(a) Immediately: Group Demand minus up to 20MW (automatically disconnected) (b) Within 3 hours: Group Demand	(c) Within 3 hours; For Group Demands greater than 100MW: Smaller of (Group Demand minus 100MW); and 1/3 Group Demand (d) Within time to restore arranged outage: Group Demand	A loss of supply not exceeding 60 sec is considered as an immediate restoration. The Recommendation is based on the assumption that the time for restoration of Group Demand after a Second Circuit Outage will be minimised by the scheduling and control of planned outages, and that consideration will be given to the use of rota load shedding to reduce the effect of prolonged outages on consumers.
E	Over 300MW and up to 1500MW	(a) Immediately: Group Demand	(b) Immediately: All consumers at 2/3 Group Demand (c) Within time to restore arranged outage: Group Demand	The provisions of Class E apply to infeeds to the distribution system but not to systems regarded as part of the interconnected Supergrid to which the provisions of Class F apply. For the system covered by Class E consideration can be given to the feasibility of providing for up to 60 MW to be lost for up to 60 seconds on First Circuit Outage if this leads to significant economies. This provision is not intended to restrict the period during which maintenance can be scheduled. The provision for a Second Circuit Outage assumes that normal maintenance can be undertaken when demand is below 67%. Where the period of maintenance may be restricted paragraph 3 of section 2 applies.
F	Over 1500 MW	In accordance with the relevant transmission company licence security standard		

Appendix 2 – Example Contingency Plan

DESCRIPTION
Europa BSP is approaching Firm Capacity. The two 132/33kV 60MVA TXs are to be changed for larger units.
OUTAGE
GT1 is to be replaced. The new unit (GT3) is to be erected and cold commissioned alongside. The incoming 132kV cables will be diverted to a new CSE structure adjacent to GT3.
DURATION
12 weeks
Customer Restoration Time
Maximum of 10 days for a period of 10 days – see below.
STAGES
1/ Clearance Outage – 4 weeks. Working adjacent to GT1 for civil works. ERTS 4/6 hours. 2/ Clearance Outage – 3 weeks. Deliver and assemble new GT3. ERTS 12/8 hours (access and lifting equipment will be in use during the working day. All will be parked in a safe condition overnight). 3/ Clearance Outage – 2 weeks. Erect new 33kV CSE structure underneath existing 33kV busbars (GT1 to 1T3). Terminate new cables. On completion, new cables to be left earthed with sufficient clearance to restore GT1. ERTS 12 hours (Scaffolding needs to be removed before GT1 can be restored). 4/ 132kV Cable Diversion – 10 days. ERTS – ON COMPLETION! Divert 132kV cable from GT1 to GT3. Existing cable is 3c Fluid Filled. New is 3 x 1c XLPE. New cables to be terminated adjacent to GT3 prior to outage. New stop / trif joint on old cable. NOTE – Jointing team to work long shifts to minimise non availability. Temporary structures to be erected to allow GT1 to be restored. 5/ Commission GT3 – 2 weeks. ERTS – GT3 48 hours on limited protection. GT1 72 hours on limited protection. Final commissioning works on GT3 including on load checks. If GT1 restoration is required, it will be possible to disconnect GT3 and reconnect GT1 on limited protection.
CONTINGENCIES
Stage 1 – Contractors to be aware that GT1 may need to be restored at any time. Stage 2 – All apparatus to be securely parked away from GT1 when not in use. All permanent access equipment to be erected with sufficient safety clearances to allow restoration of GT1. Stage 3 – Existing clearance exists under 33kV busbars to allow bars to be re-energised with new CSE structure in place BUT scaffolding needs to be removed first. Scaffolding team to be retained on 4 hour availability to remove if necessary. Stage 4 – Temporary structures to be designed and constructed prior to outage and left available on site. Detailed plans to be available on site for erection of structures if needed. All necessary conductor and fittings to be supplied and available on site. Construction personnel to be briefed on what needs doing prior to outage. Jointing teams to work double shifts during cable works. Spare tanks to be fitted to GT2 circuit to cater for loss of fluid. Oil van to be on 4 hour availability.