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Planning to Manage Power Interruption Events

Working Group
C1.17

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Executive Summary

Motivation for the Brochure

This Technical Brochure reports the work of CIGRE Working Group C1.17 in considering major unreliability events and the steps planners must take to enable them to be adequately managed. The main objectives of the Working Group (WG) were given as follows:

> [to] identify suitable plans for the controlled management of failure due to unsecured events. Restoration plans are an integral part of the managed failure plan and will also be covered by this working group.
>
> The WG's focus will not be 'classical' investments that are the subject of normal investment planning policies, but rather aspects such as protection schemes, defence plans, restoration plans, etc.. Having identified the possible technical answers, the second main objective of the WG is to provide guidance on the justification of the corresponding investments to the stakeholders.

It is argued that a number of developments in recent years are increasing the need for adequate management of power interruptions. These include

- a change in the function of system interconnection, from one of mutual assistance at times of high stress on individual systems to one of facilitating large electrical energy trades across wide areas;
- increased difficulty in building new overhead lines, whether due to rejection of planning consents or increased pressure from a diversity of stakeholders for quantified economic justification of investment;
- increased dependency in power system operation on a greater number of individual, independently owned actors and increased difficulty for system operators to obtain information from those actors;
- limited flexibility of new generating plant in comparison with older plant which are being used less or retired, the new generation being not only wind generation but also early installations of combined cycle gas turbines (CCGT);
- increased uncertainty in power transfers due to uncertainty in wind generation;
- decreased clarity of responsibility in disaggregated industries and between different interconnected systems;
- increase in size of interconnected grids, increasing the risk of event propagation; and
- the separation of generators from transmission owners, making co-ordinated planning more difficult.

In other words, the way the power system has to be operated is changing significantly and poses new challenges for the transmission system operators, who are responsible for overall system security, and for planners who are responsible for providing operators with the facilities they need.

Scope of the Brochure

A summary of notable events is presented as illustrations of the need for measures to manage power interruptions and to exemplify a number of common mechanisms of major unreliability. The summary of each event addresses the following:

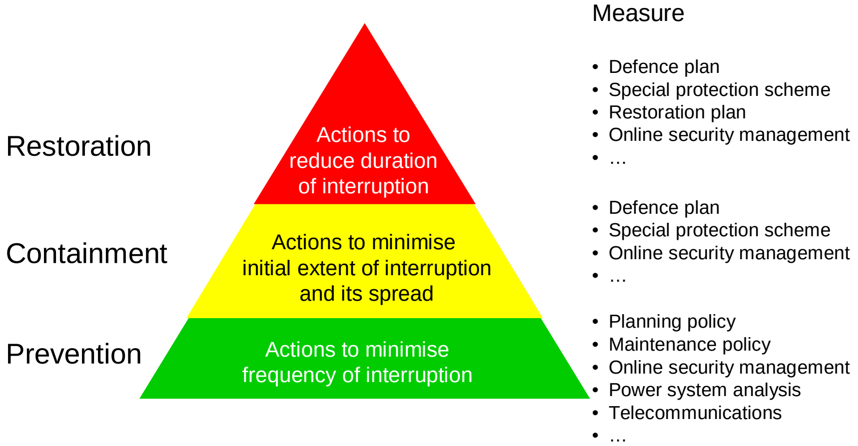
- location and a short description of event;
- power supplied by the power system before the incident;
- the duration of the incident – how long lost load endured;

- estimate of the energy not supplied;
- the geographical extension and number of people affected;
- the type of defence measure/Special Protection Scheme (SPS) in service, if any, and its operation during the incident;
- economic quantification of the damage; and
- a summary of the root causes and main countermeasures.

The main mechanisms include the following, often in combination: voltage stability; rotor angle stability; and frequency stability.

'Management' of major unreliability events is taken to concern:

- reduction of the frequency of occurrence of such events;
- reduction of the impact of such events.



Technical management of major unreliability events

Other working groups and task forces have addressed minimisation of the frequency of major disturbances; WG C1.17 has therefore concentrated on reduction of impact. (See the figure below).

	Prevention	Containment	
Measure	**Frequency of interruption**	**Initial extent of interruption**	**Duration of interruption**
Improved IT and analysis	✓	✓	✓
Training	Possibly	✓	✓
Defence plans		✓	✓
Restoration strategy			✓

Addressed in some depth elsewhere

Main focus of WG C1.17; and, how can investment in them be justified?

Scope of work of WGC1.17

The reduction of the initial extent of interruption of supply of power is the purpose of defence measures and the broad classes are reviewed. The prevalence of these different measures around the world has been assessed by means of a survey, the results of which are described in the Brochure. However, another dimension of impact is the duration of an interruption. If the initial interruption is, to some extent, controlled, the duration can be reduced. The most significant influence on the duration of a major unreliability event, though, is the effectiveness of a restoration plan and its implementation. The Brochure therefore highlights particular general issues associated with this including:

- diagnosis of the system situation and network preparation;
- a regional approach to restoration; and
- development and maintenance of a restoration plan.

A number of case studies are presented that provide details of implementations of defence measures in a number of countries. Recent developments in North America are described in respect of 'cyber security' of power system assets. Two case studies highlight some issues around the justification of investment in measures for the management of power interruptions.

Justification of investment in defence measures

The Brochure addresses the justification of investment defence measures. In a liberalised environment with multiple players, private investment and a key role played by quasi-autonomous regulators, there is an emphasis on public demonstration of economic value. This will often be a complement of an assessment of engineering risk in the form of a demonstration of a proposed measure's 'cost-benefit'. Where this is simply relative to other measures for managing the same risk, this can be straightforwardly achieved. Where an authority seeks to treat an economic assessment on a more absolute basis, some form of monetary 'damage function' or 'value of lost load' (VOLL) is likely to be required. However, this is difficult to use because it is difficult to gain agreement from all stakeholders on what is a suitable VOLL.

It is the belief of the Working Group responsible for producing this Brochure that one cannot hope to identify the 'correct' VOLL; rather, it must be subject to continuous consideration of the economic, social and political impacts of major unreliability events. This makes any case that a power system planner attempts to build for investment in measures for the management of major unreliability events vulnerable to particular circumstances or political vagaries. It is noted that a regulator's agreement to recovery of the costs of a measure for containment of power interruptions is most likely to be gained

- soon after a major interruption;
- when the transmission system is identified as a 'critical infrastructure' vulnerable to terrorist attack;
- when stakeholders are reassured (through provision of suitable documentation) that all other reasonable measures are already being taken.

In respect of 'critical infrastructure', a significant development in North America has been the attention paid to 'cyber security'. The attention paid in consideration of 'cyber security' to information and communication facilities usefully serves to highlight the serious consequences of loss of such facilities whatever the cause.

Where a clear-cut economic case for measures for the containment of disturbances is not evident, a strategic case can be made for it if it can be shown that the investment cost is relatively modest compared to the potential economic and political cost of a widespread blackout, albeit that such a probability is very low and is indeterminate with any degree of confidence. In other words, the investment is justified regardless of the probability of occurrence of the major unreliability event and is concerned with, in effect, minimising the regret associated with not undertaking the investment. That is, where the *possible*, as opposed to probable, consequence of the decision not to invest is much greater than the cost of the investment, the investment is undertaken. An example of where such an argument was used is presented in the Brochure.

A new understanding of 'security'

A description of the concept of power system security is presented. This highlights the fact that, notwithstanding system operators' application of conventions such as 'N-1' security, major unreliability events do occur, albeit rarely. Moreover, many of these are triggered by events that are apparently secured against.

It is argued that major unreliability events are often initiated by system fault events in combination with circumstances that are not concerned with outages of primary power system assets such as overhead lines, underground cables, transformers, bus sections, circuit breakers, generators and so on. These circumstances are therefore not usually detailed in security or reliability standards. These include

- a demand forecast error;
- an inter-area transfer forecast error;
- a ratings error (due, for example, to vegetation or adverse weather);
- a generator reactive power limit error; or
- unavailability of an accurate estimate of the system's current state.

Collectively, these circumstances are characterised by the state of the system and its limits not being what the operator believes them to be. Many of them may be aggravated or caused by failures of information or communication systems.

Another issue concerns fault outages that occur outside of an area visible to a system operator but which nevertheless affect the area for which that system operator is responsible.

The view of WGC1.17 is that while the above events and circumstances might not drive 'classical' investment in additional network capacity or cause restriction of power flows in real time, because of their role in major unreliability events, they should be explicitly considered in cases for investment in defence measures designed to contain their impact were they happen. In addition, they may be used in operational timescales, rather as 'adaptive' security standards are now in a number of places. Their purpose then would be to minimise the risk of inadvertent interruption of load due to unnecessary action of defence measures through the clarification of when defence measures should be 'armed'.

Coordination of aspects of power system planning and operation

Continual operation of generation is critical to a power system's ability to proceed through a major disturbance, minimise the load interrupted and shorten restoration time. However, it has seemed to the members of Working Group C1.17 that aspects of coordination between transmission system planning and operation and, in particular, the performance of generation would benefit from renewed attention. Particular issues highlighted include adequate coordination of various generator protection systems and the designed capability of generation to contribute to control of the system under major disturbances.

A number of major disturbances have been provoked or aggravated by a combination of factors related to protection and control systems. These factors fall into several categories including design deficiencies, installation flaws, equipment malfunction and human errors during maintenance and testing. The detailed performance of protection and control is sometimes beyond a power system planner's normal priorities while wider system behaviour is outside those of protection and control engineers. In view of the role of protection and control in major unreliability events, it is argued that behaviour of these facilities under somewhat abnormal system conditions is worthy of particular attention and will be of interest to both planners and operators. Recognising a planner's role in providing adequate facilities to operators and the difficulty of changing systems once they are in operation, these aspects of coordination should perhaps be highlighted especially for planners who have an opportunity to ensure adequate performance in advance of both local facilities and the system as a whole in advance of connection of new generation.

Other aspects of coordination are also highlighted:

- the importance of monitoring and data recording for post-event analysis;
- compliance testing of generators and enforcement of rules;
- the coordination of standards; and
- the coordination of different defence measures.

In view of the importance of some of the above issues for reliable operation of the power system as a whole and the interaction of planning and operation with issues with each other and with the design and operation of protection, WG C1.17 recommends that a new working group should be established. This is suggested to address at least the following:

- international best practice for generator performance under disturbances and enforcement of compliance with standards considered both at time of an application to connect and when operating;
- coordination of protection between ‘local’ objectives and ‘system performance’ considerations, both for network protection systems and the various forms of generator protection.

In view of the roles that system planners, operators and protection engineers each have in the above, it is recommended that any new working group should have input from study committees C1 (System Development and Economics), C2 (System Operation), B5 (Protection) and perhaps also A1 (Rotating Electrical Machines), with leadership and management undertaken by either C1 or C2. In view of its concern with modelling and system performance, some contribution from C4 (System Technical) may also be appropriate.

Other issues not considered by WG C1.17 are arguably also worthy of attention:

- the use of transmission spares and sharing of such resources between utilities; and
- assurance of the reliability of low voltage supplies to substations, in particular for protection and control systems;
- the contribution that rapid manual or automatic switching of loads between grid supply points at a sub-transmission or distribution level might make to the limitation of impact of loss of supply events, the importance of this for realisation of ‘smart’ or ‘self-healing’ grids and the extent to which it is limited by currently available facilities for reliable and precise identification of fault location.

1 Introduction

1.1 Introduction to this Brochure

This Technical Brochure presents the conclusions of CIGRE Working Group C1.17 (WG C1.17), established in early 2006 by CIGRE Study Committee C1 on System Development and Economics to investigate “Planning to Manage Power Interruption Events”.

Power systems are conventionally planned and investments made to meet a defined level of redundancy or failure of different individual system assets concerned with transmission, generation or the connection of demand. Even with this inherent security, failures of power systems can and do occur: it is impossible to eliminate risk completely.

In order to meet the demands of electricity markets and environmental constraints, networks are increasingly planned and operated to their technical limits. Super grids are formed in order to reap the economic and security benefits of larger grids. Consequently, the impact of network failure is likely to become more widespread and the need to plan and manage ‘major unreliability events’ is becoming more important. When failure occurs it should take place on a controlled basis, this requires planners and system operators to develop and implement suitable strategies for managing the failure path. Planners in particular need to deliver the investments needed to achieve this. It is the identification and justification of such investments that this Working Group is mainly concerned with. However, this Brochure also presents some recommendations concerned with the background against which power system planning is carried out and for which correct assumptions are essential to achievement of a planner’s objective of enabling secure operation of the system and adequate defence against major unreliability events.

1.2 Objectives of the Working Group

The main objectives of the Working Group (WG) were presented in the Terms of Reference[1] as follows:

> This WG will identify suitable plans for the controlled management of failure due to unsecured events. Restoration plans are an integral part of the managed failure plan and will also be covered by this working group.
>
> The WG’s focus will not be ‘classical’ investments that are the subject of normal investment planning policies, but rather aspects such as protection schemes, defence plans, restoration plans, etc.. Having identified the possible technical answers, the second main objective of the WG is to provide guidance on the justification of the corresponding investments to the stakeholders.

A previous WG established by C1 – WG C1.2 on “Maintenance of Acceptable Reliability in an Uncertain Environment” – coined the term ‘major unreliability event’ [1]. WG C1.17’s concern with management of power system failure is probably best understood in relation to such ‘major unreliability events’ since

- their mechanisms are often complex;
- their impact is very large; and
- due to their rarity, it is sometimes difficult to gain support for measures to manage them.

[1] The Terms of Reference are reproduced in full in Appendix A

In contrast, in most years of operation, most energy that is not supplied due to network failure is as a consequence of events on generally radial distribution or sub-transmission systems where redundancy of connections is less; these events are usually rather localised and generally easily explained. Such distribution or sub-transmission originated events with only local impact are therefore not the subject of this Brochure.

A number of excellent reports on major power disturbances and defence measures have been produced by other committees and working groups, among them [2] and [3] produced on behalf of CIGRE and the IEEE. Working Group C1.17, which has been responsible for the production of the present Brochure, has not sought to repeat their work. For example, a major theme of, for instance, [3] has been the *prevention* of major unreliability events. Instead, WG C1.17 has concentrated on *containment*, i.e. limitation of the extent of the impact of a power interruption, measured either in terms of the power initially interrupted or the restoration time.

Where it helps the development of ideas and background in the present Brochure, the work of other groups has been drawn upon and WG C1.17 has attempted to fill in apparent gaps in previous reports. One of these is between system operators' main concerns and those of power system planners. WG C1.17 has then sought to present some ideas and recommendations on investments necessary to facilitate the management of power interruptions.

References to other groups' reports will be made throughout the rest of the report where most relevant.

A number of issues are related to the management of power interruptions but are not concerned with the design of the power system itself. These include the training of operational staff, the availability of human resources for restoration activities, coordination among different emergency services and public relations. In order to retain a sufficiently tight focus for the WG and in recognition of the expertise of its members, these issues were regarded as out of scope.

1.3 Motivation for the Working Group and this Brochure

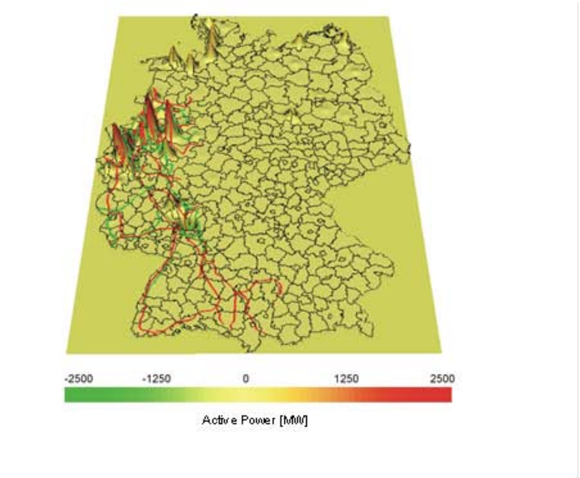
A number of major unreliability events around the world in the second half of 2003 re-focused electric utilities', regulators', governments' and consumers' attention on risks of widespread power system disturbances. However, it has also been suggested, by the authors of [1]-[3] and of the present Brochure among others, that, in comparison with earlier reviews of major disturbances, a variety of factors that have grown to significant levels in many parts of the world in the last 10 years are contributing to an increase in the risk of such disturbances.

Many of these additional factors were described in [1], concern either economic or technical factors and may be summarised as

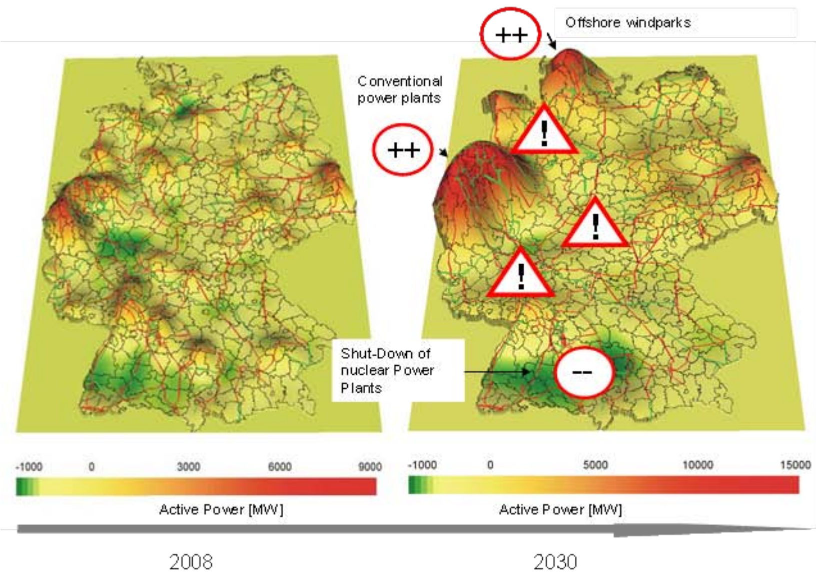
- a change in the function of system interconnection, from one of mutual assistance at times of high stress on individual systems to one of facilitating large electrical energy trades across wide areas;
- the effect of rules designed to aid the operation of an electricity market and concerning the timing of declaration of market positions by trading parties is increasing uncertainty for power system operators and limiting the range of possible actions;
- increased difficulty in obtaining permits for new transmission lines;
- increased pressure from stakeholders for quantified economic justification of actions by power system planners and operators;
- increased dependency in power system operation on a greater number of individual, independently owned actors;

- limited flexibility of new generating plant in comparison with older plant being less used or retired, not only wind generation but also early installations of combined cycle gas turbines (CCGT);
- increased uncertainty in power transfers due to uncertainty in wind generation;
- decreased clarity of responsibility in disaggregated industries and between different interconnected systems.

In other words, the way the power system has to be operated is changing significantly and poses new challenges for the transmission system operators, who are responsible for the overall system security, and for planners who are responsible for providing operators with the facilities they need. Figure 1.1 shows one example of how this trend is developing in Germany: the minimum transmission losses principle of producing the energy close to load centres is violated more and more.



A)



B)

Figure 1.1: Electrical energy trends in Germany [4]

A) Incremental consideration 2006-2012 (Amprion) (wind on-/offshore + requests conventional PP)

B) Development of installed capacity from 2008 to 2030

The authors of [1] also pointed towards communication issues affecting the maintenance of acceptable reliability. In one respect – that of a tendency for individual actors in an electricity market to withhold information perceived as being of commercial value – the information to a system operator is becoming less. In another – the growth of interdependency between different systems – the need for information to be shared more widely becomes greater.

In addition to the above issues, major challenges are presented to electric power utilities in the industrialised world by the need to renew aged systems while accommodating increased transfers of power. Finally, while the authors of this Brochure are not aware of substantive quantification of the effect, there is a concern that climate change, as well as leading to increased use of uncertain generation, will lead to an increase in the frequency or severity of extreme weather.

Chapter 2 of this Brochure presents a summary of various major unreliability events. Out of this, some common causes and issues emerge. Furthermore, the following assertions can be seen to be justified:

1. there have been and will continue to be large power interruption events, regardless of the security standard applied and level of redundancy built into a system;
2. due to the greater stress and complexity of systems, the impacts of these events are greater than before;
3. as a consequence, there is a need for failure events to be controlled or managed in some way and for investment to enable this control.

The main questions that arise out of these assertions would seem to be:

- what are the most effective means of controlling or managing power interruption events?
- to the extent that these means require planning and investment, how can that investment be justified to stakeholders?

The significance of this last question can be seen from the final report by UCTE[2] on the European system disturbance of November 4, 2006 in which it was stated that

> "the need for a more complex management of interconnected grids is obvious, but has so far not always been supported by regulators and main stakeholders when TSO operators have requested more generation data and intervention rights, particularly in emergency situations." [5]

It is in light of this concern about the degree of support given by regulators and main stakeholders that, as well as outlining the methods and facilities that can be used to manage power interruptions, this Brochure addresses how investment in such facilities can be justified. The specific question of behaviour of generators, including the availability of data describing generators' characteristics and its accuracy, is also discussed.

1.4 The Planner's Role in the Management of Major Unreliability Events

The main function of a transmission system planner historically has been the timely provision of sufficient network capacity for the system to be operated in accordance with relevant security or reliability standards without undue restriction of the economic operation of generation.

[2] UCTE is the Union for the Co-ordination of Transmission of Electricity. It was superseded in 2009 by the European Network of Transmission System Operators for Electricity (ENTSO-E)

The electricity flows through the grid are a consequence of the commercial behaviour of the market participants. This can be seen from both long term and short term perspectives. From the long term perspective, geographical aspects are dominant. Regions with more generation than demand normally export to regions with more demand than generation. Investments in transmission grids are, for the most part, based on the flows consequential to these characteristics.

Due to the fact that grid investments are expensive and time consuming, the capacity available in operational timescales is not always sufficient. In recent years on many continents, this has particularly been the case in respect of cross border connections to accommodate all the desired commercial flows. As a consequence, auction systems have come into place to sell the available capacity to market participants. There are long term, day ahead and intra day capacity markets. To maximise social welfare in a region, there is a huge pressure on TSOs to increase the amount of transmission capacity.

Liberalisation of the market and large increases in wind generation have caused highly unpredictable flows. This has considerable consequences for short term operation; unpredictable frequent violation of conventional ‘*N*-1’ security would occur if no action were taken. Therefore, more precise appraisals of network capacity under a wide range of scenarios are required, based initially on multiple power flows. Depending on how much security margin is built in the calculation model the chance of an *N*-1 violation still exists. Combined with another event such as generator failure, breakdown of a network component such as a transformer, line or cable or failure of a distribution network, a power interruption in the transmission network can occur.

One author has asserted [6] that investment in additional network capacity will fail to reduce the risk of major interruptions to supply. However, whether this happens depends largely on whether the additional capacity is exploited simply to facilitate still greater transfers in the manner outlined above. The planner nevertheless remains responsible not only for providing network capacity but also for providing a system operator with the means of managing the consequences of *N*-1 violations or combinations of outage events.

1.5 Outline of the remainder of this Brochure

The remainder of this Brochure is organised as follows:

- **chapter 2:** a summary of past major unreliability events, with a particular focus on
    - initial conditions
    - mechanisms
    - responses and consequences (including equipment damage)
    - restoration times
- **chapter 3**: a discussion of the meaning of ‘security’ in power systems and how some development of that may help in the identification of necessary investments for system defence;
- **chapter 4**: a discussion of what is meant by ‘management’ of power interruptions and a review of the main methods and facilities used;
- **chapter 5**: a discussion of issues around the performance of generating plant and its influence on the propagation of major unreliability events;
- **chapter 6**: a discussion of issues around the need for co-ordination between the activities of power system planners, operators and generators;
- **chapter 7**: an overview of the defence measures and special protection schemes (SPS) implemented by different utilities around the world and discussion on justification of investment in measures for the management of power interruptions;
- **chapter 8**: presentation of a number of detailed case studies illustrating the issues discussed elsewhere in the Brochure;

- **chapter 9**: a presentation of the main conclusions and recommendations arising out of the Working Group's work.

1.6 Acknowledgements

This Brochure would not have been possible without a great many important contributions. The Working Group is grateful to those engineers from around the world who responded to the survey described in Chapter 7 and to colleagues who have engaged in discussion of the issues described.

All the members of the Working Group have contributed, not least in the discussions at the various meetings of the Group, but particular thanks are perhaps due to the following who have taken a lead in writing and coordinating material for the various chapters.

1 Keith Bell and Klaus Vennemann
2 Alberto Berizzi and Klaus Vennemann
3 Keith Bell, Pieter Schavemaker and Siem Bruijns
4 Klaus Vennemann, Sebastien Henry and Vladimir Stanišić
5 Vladimir Stanišić
6 Vladimir Stanišić and Keith Bell
7 John Seelke, Darren Chan and Keith Bell
8 Klaus Vennemann, Algi Özkaya, Mihai Cremenescu, Sebastien Henry, Darren Chan, Keith Bell, John Seelke
9 Keith Bell

Finally, particular gratitude is expressed to the Secretary of C1, Peter Roddy of National Grid in the UK, for his proof-reading and useful suggestions.

1.7 References

[1] CIGRE Working Group C1.2, *Maintenance Of Acceptable Reliability In An Uncertain Environment*, Technical Brochure 334, CIGRE, December 2007.
[2] CIGRE Task Force C2.02.24, *Defense plan against extreme contingencies*, Technical Brochure 316, CIGRE, April 2007.
[3] IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007.
[4] Amprion-TSO
[5] UCTE, *Final Report System Disturbance on 4 November 2006*, – see http://www.ucte.org/pdf/Publications/2007/Final-Report-20070130.pdf
[6] D.S. Kirschen, "Do investments prevent blackouts?", *Proc IEEE Power Engineering Society General Meeting*, Montreal, June 2007.

2 Review of Major Unreliability Events

2.1 Introduction

The Chapter presents a brief summary of past events to help explain the motivation for the report, and draws out some particular issues that, it seems, have not particularly been addressed before and which WGC1.17 will concentrate on.

The reviews of past events focus on summaries of the following:

- initial conditions
- mechanisms
- responses and consequences (including equipment damage)
- type and operation of defence mechanisms
- restoration times

The operation of defence measures/SPS will be highlighted in order to stress the importance of defence mechanisms and therefore the need for investments on these emergency control tools.

2.2 Major events

The Section presents a summary for each event considered. The details are not provided as it is not the scope of the Report; however, for the interested readers, some references are also indicated.

In each table, the **location** and a **short description** of events are provided. Additionally, the following issues are also presented, in cases published in the technical literature: the **power supplied** by the power system before the incident, in order to understand the overall conditions of the system; the **duration** of the incident, in the sense of the time the system was not able to supply its total load; and an estimate of the **energy not supplied** (in some cases, the interrupted power will alternatively be given); the geographical **extension** and the **people** affected; the **type** of defence measure/SPS in service, if any, and its **operation** during the incident. An **economic quantification** of the damage resulting from the incident will also be presented if available; the root causes as well as the main **countermeasures** taken by the system operators after the event, i.e., lessons learned.

The events are ordered according to time, in order to highlight the technical improvements made available during the years.

Location	North East USA and Canada, November 9-19th, 1965, 17:16
Description of events	At 5:16 pm on November 9, 1965 the incident was initiated by the operation of a relay on a 230 kV line near Niagara Falls. This inappropriate relay action initiated power system cascading that resulted in the splitting of the power system in 5 areas. The Ontario Hydro area lost about 3800 MW of load; the Northern New York area did not suffer any loss of load; the area close to Niagara was initially characterized by an excess of generation and overfrequency, but tripping of some units resulted in underfrequency and blackout due to frequency instability; the area of New York and New England suffered a complete blackout due to deficiency of about 1000 MW and also some power plants for a total power of 1500 MW were damaged; Maine and New Hampshire were isolated, but did not experience blackout.
Power before the incident	
Duration and Energy not supplied	20 GW lost, 13 hours
Geographical extension and people affected	80,000 square miles, 30 million people
Type of SPS in operation	
Operation of SPS during the incident	---
Economic quantification	
Remedial actions after the fact	The following practices are a direct result of this blackout: • Coordinated regional power system planning and operation • Application of underfrequency load shedding • Increase black start capability • Set and update restoration procedures • Generator tripping for lost transmission
References	• Federal Power Commission, *Report to the President on the power failure in the northeastern United States and the province of Ontario on November 9-10, 1965*. • IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007 • J.D.McCalley, *operational defense of power system cascading outages.* IEEE PES T&D Conference &Exhibition, 2008.

Location	New York, USA, July 13th, 1977.
Description of events	At 8:37:17 pm, a lightning strike caused the trip of two parallel transmission lines and the consequent trip of a nuclear unit that had been generating 883 MW. Due to a design error in the protective system, also line importing power tripped, not causing any particular overload. 18 minutes later, a second strike caused the trip of two additional parallel transmission lines, re-closure did not operate properly, resulting in some overloads due to the large imported power. Such thermal overloads caused sagging into a tree and further trips left four remaining interconnections (one at 230 kV and three at 138 kV) to carry 1,900 MW of import power. After some attempts to re-dispatch the power, several lines tripped and frequency dropped to around 57.8 Hz and then began recovering after the activation of three blocks of underfrequency load shedding. Unfortunately, as the frequency returned to about 60 Hz, a loss of excitation relay operated at a 844 MW generation unit: frequency fell rapidly again to 57.8 Hz before slowing significantly; the fourth and final block of underfrequency load shedding activated by this time but was insufficient to reverse the frequency decline. Frequency continued to slowly fall at a rate of about 1 Hz/minute until additional units tripped and lead to a rapid blackout of the islanded Con Edison system.
Power before the incident	6,091 MW
Duration and Energy not supplied	22 hours
Geographical extension and people affected	3 million people
Type of SPS in operation	Underfrequency load shedding, in 4 load blocks.
Operation of SPS during the incident	Underfrequency load shedding worked properly, but the incorrect operation of other relays resulted in a loss of generation that was impossible to recover.
Economicquantification	300 millions $
Remedial actions after the fact	
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007 • J.D.McCalley, *operational defense of power system cascading outages.* IEEE PES T&D Conference &Exhibition, 2008. • US Dept. of Energy, FERC, *The CON Edison power failureof July 13 and 14, 1977.* Final Staff Report, June 1978.

Location	France, December 19th, 1978, 8:26.
Description of events	Starting from 8 am, the demand increase was such that the Automatic Load Frequency Control was unable to balance the load: power flows from East to Paris increased leading to a degradation of the operating conditions of the EHV system (overloads and voltage drops). The tripping of the 400 kV Bezaumont-Creney line, due to overcurrent protection, resulted in a cascade of trips in the next 20 s and by the trip of some hydro units while the East and South-East areas stayed connected to the European system. Within the areas separated from the European network, voltage and frequency instability conditions persisted. A new balanced condition, between generation and load, could not be achieved and the operation of protective relays on generating units (under-voltage or underfrequency) quickly led to a complete blackout in these regions. Restoration started immediately and at 8:46 the 400 kV system was almost completely re-energized, with loads being progressively brought back on-line. However, between 9:00 and 9:07 am, the load on the lines in the Alps area increased quickly. Consequently, at 9:08 am over-current tripping of 400 kV and 225 kV lines resulted in decaying voltage on the 400 kV network of the Western system, which was previously partly re-energized. A subsequent restoration took place and was completed at about 6 pm.
Power before the incident	38.5 GW
Duration and Energy not supplied	10 hours, 120 GWh. Load initially lost: 29 GW
Geographical extension and people affected	France
Type of SPS in operation	Underfrequency load shedding
Operation of SPS during the incident	In some parts of the system the low voltage levels resulted in the loss of generators, by operation of undervoltage relays. This prevented the defence system from operating properly.
Economic quantification	
Remedial actions after the fact	
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007 • J.D.McCalley, *operational defense of power system cascading outages.* IEEE PES T&D Conference &Exhibition, 2008.

Location	Sweden, December 27th, 1983, 12:57
Description of events	The blackout was initiated at 12:57 after a breakdown of a disconnector in one of the main substations feeding Stockholm. The breakdown caused the tripping of all lines connected to the station, including two of the seven 400 kV lines of a power corridor. This resulted in an overloading of the remaining lines and voltage drops in the southern parts of the network. As load recovered after the initial voltage drops, the overloading became increasingly severe, resulting in cascading outages of the transmission lines in the interface and eventually to separation of the power system. Southern Sweden experienced a voltage collapse. The event also caused outages in Eastern Denmark. Three main power plants tripped due to low voltages before all the cables to Sweden tripped as a result of power oscillations.
Power before the incident	
Duration and Energy not supplied	Duration about 2 hours. Energy not supplied: 24000 MWh + 765 MWh in Denmark. Power interrupted: 11400 MW+520 MW in Denmark.
Geographical extension and people affected	4.5 million people
Type of SPS in operation	
Operation of SPS during the incident	
Economical quantification	
Remedial actions after the fact	
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007 • J.D.McCalley, *operational defense of power system cascading outages.* IEEE PES T&D Conference &Exhibition, 2008.

Location	Brazil, april 18th, 1984, 16:34.
Description of events	At 4:34 pm, a 500/345 kV transformer (out of two transformers) of a substation was shutdown when operating at its overload limit due to hydro needs of the water system. At 4:43 pm, the second 500/345 kV transformer tripped out, followed by an almost simultaneous tripping of seven circuits in the 500 kV and 345 kV transmission systems. This caused power oscillations between some power plants and the rest of the interconnected system giving rise to cascading shutdowns. The 750 kV transmission system was opened by out of step protection to avoid propagation of oscillations to the South region.
Power before the incident	15762 MW
Duration and Energy not supplied	
Geographical extension and people affected	
Type of SPS in operation	Out of step protection
Operation of SPS during the incident	
Economical quantification	
Remedial actions after the fact	
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007 • J.D.McCalley, *operational defense of power system cascading outages.* IEEE PES T&D Conference &Exhibition, 2008.

Location	Tokyo, Japan, July 23rd, 1987, 13:19.
Description of events	Due to high temperatures, TEPCO was ready to face a high load, with shunt capacitors connected. During lunch break electricity demand declined from 39.1 GW to 36.5 GW, and therefore some shunt capacitors had to be disconnected. After lunch break, these shunt capacitors were expected to be switched on automatically but, since the load increase was faster than ever experienced previously, voltage and reactive power controls could not keep up with it, and thus the bus voltages started to decline. At 13:19, when the 500 kV bus voltages in the western part of the system dropped below 400 kV, two 500 kV transmission lines tripped due to zone 4 impedance relays, and one 500 kV transmission line tripped due to a phase comparison relay. These impedance relays operated because the voltage drop forced the apparent impedance to be inside the reach of the relays. In addition to 500 kV transmission lines, four 275 kV transmission lines and four 275/66 kV transformers tripped due to zone 4 impedance relays resulting in the loss of about 8 GW of load. Note that no fault occurred to cause these relays to operate. However this saved the system, as the voltage collapse was stopped. Since the voltage drop caused the apparent load to be lower in MW value, frequency was higher than the normal operating range before the loss of the load. At 13:19, the loss of the load caused a sudden increase in frequency up to 50.74 Hz and the trip of three units. Frequency decayed to the normal operation range within about five minutes by load restoration and governing operation of generating units.
Power before the incident	40 GW
Duration and Energy not supplied	8 GW lost, 21% of total load for 3:35 hours
Geographical extension and people affected	2.8 million people
Type of SPS in operation	No SPS against the particular phenomenon (voltage collapse)
Operation of SPS during the incident	
Economical quantification	
Remedial actions after the fact	Foundation of voltage and reactive power control. Installation of Under Voltage Load Shedding
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007 • A.Kurita, T.Sakurai, *The power system failure on July 23, 1987 in Tokyo.* 27th Conference on decision and Control, Austin (Texas, USA), Dec.1988. • T.Ohno, S.Imai, *The 1987 Tokyo blackout*. IEEE PSCE, 2006.

Location	Brazil, December 13th, 1994, 10:12.
Description of events	At 10:12 am, while performing tests at a HVDC Converter Station, a human error caused the operation of the forced isolation scheme. The two HVDC bipoles were blocked, resulting in a shortage of 5,800 MW in the interconnected system. This resulted in a significant voltage dip in the São Paulo area, oscillations as well as loss of synchronism between a large hydro power plant and the Southeastern Region; this hydro plant, due to the opening of the 750 kV transmission system remained connected to the Southern region. The SPS for generation shedding at the power plant, designed to prevent overfrequency in the South system, was insufficient and the consequent acceleration and overvoltages caused the opening of a 750 kV circuit, the disconnection complete of the hydro power plant and the consequent large generation deficit. The underfrequency load-shedding schemes operated.
Power before the incident	5,800 MW
Duration and Energy not supplied	
Geographical extension and people affected	
Type of SPS in operation	Both Underfrequency load shedding and special scheme for disconnection of the large power plant in case of excess of power.
Operation of SPS during the incident	The SPS to disconnect the power plant from the power system in case of increase of frequency did not operate properly; undefrequency load shedding worked fine.
Economical quantification	
Remedial actions after the fact	Investigations on the following topics: 1. possibility of overvoltages after the action of underfrequency load shedding. 2. Dynamic setting of the underfrequency load shedding. 3. SPS settings must be more selective.
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007

Location	West USA, July 2nd, 1996, 14:24.
Description of events	On the western system, on July 2nd, 1996, environmental mandates had forced Bonneville Power Administration to curtail generation on the lower Columbia River in order to aid fish migration. This resulted in both a reduction in voltage support and system inertia in an area from which both the California – Oregon Intertie (COI) and the Pacific HVDC Intertie (PDCI) originate. This had two consequences, firstly it threatened the ability of those transmission paths to sustain heavy imports into California, and secondly it resulted in an increase of system exposure to the north-south inter-area mode of oscillation. At 02:24 pm local time, a 345 kV line from SW Wyoming into SE Idaho tripped due to arcing to a tree. Relay error also tripped a parallel 345 kV line, initiating trip of two 500 MW generators by stability controls. Inadequate reserves of reactive power produced sustained voltage depression in Southern Idaho, accompanied by oscillations throughout the Pacific Northwest and northern California. About 24 seconds after the fault, the outage cascaded through, tripping small generators near Boise plus the 230 kV line from Western Montana to SE Idaho. Then voltage collapsed rapidly in Southern Idaho and the north end of COI. This was further aggravated by false tripping of 3 units at McNary. Within a few seconds, the western power system was fragmented into five islands, with most of southern Idaho blacked out.
Power before the incident	
Duration and Energy not supplied	11743 MW
Geographical extension and people affected	1.5 million people
Type of SPS in operation	
Operation of SPS during the incident	
Economical quantification	
Remedial actions after the fact	
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007 • J.D.McCalley, *operational defense of power system cascading outages.* IEEE PES T&D Conference &Exhibition, 2008.

Location	West USA, August 10th, 1996, 15:42.
Description of events	On this day, due to high temperatures, loads were also high and imports from Canada were about 2300 MW, while the same voltage problems as on July 2nd were still present. Some contacts to trees occurred: at 15:42:37, a first 500 kV line tripped, opening another 500 kV line due to the breaker configuration at Keeler. The line was carrying 1300 MW. The consequent shift of flow reduced the voltages in the area and resulted in a large increase in power flow on lower voltage transmission lines. After 5 minutes, thermal problems caused the undesired trip of a 115 kV line and the tree contact of another 230 kV line. Also, 13 generators tripped in 80 s due to the misoperation of their exciter protection. This initiated undamped inter-area oscillations in the system. For about 40 seconds, 0.25 Hz undamped oscillations were sustained. As frequency decayed and intertie power flow fell below schedules, automatic generation control (AGC) and governors caused generation and Canadian exports to the northwest U. S. to increase These resulted in increased north-to-south power flow on the remaining lines: system voltage decayed and power oscillations grew rapidly resulting in the interruption of the power flow after 6 minutes. This initiated a total system breakup into 4 islands.
Power before the incident	30,000 MW
Duration and Energy not supplied	
Geographical extension and people affected	7.5 million
Type of SPS in operation	Underfrequency load shedding. An islanding scheme for separation of the western interconnection into north and south islands was removed from service following the addition of a third 500-kV circuit from Oregon to California.
Operation of SPS during the incident	It worked, but undesired behaviour of protection schemes prevented from success.
Economical quantification	1 billion $
Remedial actions after the fact	Improvement on models adopted in the planning and operational planning, especially for excitation systems, voltage control, damping of inter area oscillations. The above mentioned scheme for islanding was updated and installed because simulations demonstrated that should it be in service, the breakup would have not been so heavy. Better design and coordination of protections (especially for generators) was carried out able to face abnormal voltage and frequency operating conditions occurring during islanding.
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic* • J.D.McCalley, *operational defense of power system cascading outages.* IEEE PES T&D Conference &Exhibition, 2008. *Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007

Location	Brazil, March 26th, 1997, 9:18.
Description of events	A human error on the operation of a selector switch at a hydro power plant tripped the 345 kV differential bus protection systems, resulting in the shutdown of the 1,300 MW generated by the power plant. This caused the cascading trip of seven 345 kV transmission lines that in turn caused the tripping of other transmission interconnection lines. The loss of these elements separated the system into two parts. The interrupted load reached a total of 5,804 MW.
Power before the incident	
Duration and Energy not supplied	5804 MW
Geographical extension and people affected	
Type of SPS in operation	
Operation of SPS during the incident	
Economical quantification	
Remedial actions after the fact	
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007

Location	Chile, May 1st, 1997, 23:23.
Description of events	The outage of a 154 kV line caused a voltage collapse, which had at first a slow behaviour, but at the end a very fast voltage degradation. This is also due to the very longitudinal structure of the Chilean power system, characterised by a generating centre located far from the demand, with an additional generating unit in the middle of the transmission line connecting both ends. The main cause for this voltage collapse in the Chilean system was the overexcitation limits in some generating units, associated with the maximum loadability of the system. Operators tried to avoid the voltage collapse by connecting banks of capacitors, however, the system still collapsed, as these capacitors were not connected quickly enough.
Power before the incident	About 3000 MW
Duration and Energy not supplied	30 minutes, about 80% of load was lost
Geographical extension and people affected	
Type of SPS in operation	
Operation of SPS during the incident	
Economical quantification	
Remedial actions after the fact	
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007

Location	Malaysia, November 18th, 1998, 13:22.
Description of events	At the time of the incident, the North East subsystem was exporting about 1,668MW to the South Central subsystem compared to a normal load transfer of about 1,200MW, through three 275 kV double circuit lines. In particular, the North – Central connection comprised a 275 kV double circuit line and two 132 kV lines. At 13:10, a circuit of a 275 kV double circuit line from North sagged too close to a tree and flashed over. The fault was cleared, but four minutes later a second flashover occurred and the distance protection on that circuit could not clear the fault. This caused the adjacent 275kV circuit to trip and this actually weakened the system. The power from the North started to flow to the Central/South through a much longer path. Power oscillations were observed on these 275 kV lines. The fault was finally cleared 90 s after the start of the second flashover, by back-up protections. The delayed fault clearing resulted in the power oscillations becoming stronger and this resulted in the 275 kV lines connecting the North/East to the Central/South systems to trip due to power swing: the system was separated into two islands. Tripping of several generation units, especially combined cycle gas turbine units, during this oscillation period prior to the system separation, further reduced the voltage support of the South Central area. The system frequency in the North/East island reached 51.68 Hz, had an oscillation to 49.7Hz and returned to normal in about 3 minutes. 17 generating units tripped after system separation due to reverse power and excitation system control problem while 3 units were taken off manually. The total generation loss was 1,760 MW. The Central/South island faced a deficit of 1,830 MW in generation in an island size of 5,049MW or 36% and the system frequency in the island dipped to 48.1 Hz in 4 seconds, returned to 49.5 Hz in 45 seconds and returned to normal in about 3 minutes. The situation was further exacerbated by the loss of the tie-line to Singapore at 49.1 Hz.
Power before the incident	7,553MW
Duration and Energy not supplied	from several minutes to about 3 hours
Geographical extension and people affected	1.4 million customers
Type of SPS in operation	Underfrequency load shedding
Operation of SPS during the incident	1,771MW of automatic underfrequency load shedding and 338 MW of manual load shedding. Compared to a similar incident in 1996, This improvement was due to actions taken from lessons learnt after the August 3rd 1996 incident, in particular the prompt and adequate operation of the underfrequency load shedding scheme, and modifications to the gas turbine control systems during severe frequency deviations.
Economical quantification	
Remedial actions after the fact	
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007

Location	Brazil, March 11th, 1999, 22:16.
Description of events	Following a single-phase short-circuit on a 440 kV bus, the remote transmission line protection systems were activated; bus interconnections were also opened. Consequently, six 440 kV circuits were tripped, initiating an oscillatory process that ended up with the cascading shutdown. In particular, a 750 kV transmission system tripped, isolating a large hydro power plant from the South system and the same occurred for many 440 kV transmission lines. The total generation loss was 2,300 MW. Additionally, some 500 kV lines in the Southern system were tripped, activating the SPS in the region, a voltage collapse in the São Paulo area occurred and many 500 and 345 kV transmission lines were lost, together with an HVDC link, adversely affecting the power supply to the states of Rio de Janeiro and Espírito Santo. In the same manner, the North/South interconnection was tripped by its out-of-step protection. Considering the extremely severe event and the small secondary incidents which occurred during the restoration process, recovery from the black-out has been seen as satisfactory, mostly due to proper actions taken by the teams that dealt with the disturbance, in spite of the delay in restoring the system in certain areas.
Power before the incident	
Duration and Energy not supplied	4:20 hours, 25,000 MW lost
Geographical extension and people affected	75 million people
Type of SPS in operation	Underfrequency load shedding
Operation of SPS during the incident	
Economical quantification	
Remedial actions after the fact	Highlighted the need for constant updating of SPS systems. Definition of a PLC-based SPS triggered by network topological changes.
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007 • X.Vieira Filho, L.A.S.Pilotto, N.Martins, A.R.C.Carvalho, A.Bianco, *Brazilian defense plan against extreme contingencies.* IEEE PES Summer Meeting, July 2001.

Location	Crete, October 25th, 2001, 8:07.
Description of events	The first unit that tripped was one of the two gas turbines (GTs) of a combined cycle plant due to low pressure of supplied diesel oil. Following this, the steam turbine also tripped: the total loss was 58 MW in 26 seconds. As a result, underfrequency protections initially shed about 25 MW of load and then a further 33 MW. The frequency oscillated between 48.7 Hz and 49.33 Hz. At 08:08:30 am the second GT of the combined cycle was tripped due to voltage oscillations, followed by the outage of the wind farm production. After that, the available production was only 100 MW compared to a load of 130 MW. Until this moment the automatic load shedding was effective, but the loss of the wind power caused the frequency collapse in 45 s.
Power before the incident	233 MW (vs a system peak load 471 MW)
Duration and Energy not supplied	
Geographical extension and people affected	
Type of SPS in operation	Underfrequency load shedding
Operation of SPS during the incident	58 MW automatically shed
Economical quantification	
Remedial actions after the fact	
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007

Location	Brazil, January 21th, 2002, 13:34.
Description of events	The incident was caused by the rupture of a conductor of a 440kV transmission line that resulted in a single-phase short circuit. This fault was correctly cleared by the line protection system, but caused the unsuitable opening of the other circuit of the same transmission line due to the non selective action of the primary distance protection system. This initiated an oscillatory process that forced the shutdown of the 440 kV transmission corridor. The control actions implemented after the blackout of 1999 permitted the controlled opening of the North/South and South/Southeast interconnections, thus avoiding the propagation of the oscillations and minimizing the consequences of the disturbance.
Power before the incident	
Duration and Energy not supplied	No load disconnected
Geographical extension and people affected	
Type of SPS in operation	Controlled separation?
Operation of SPS during the incident	Thanks to the improvements in the control system after a previous blackout, the incident consequences were minimal.
Economical quantification	
Remedial actions after the fact	
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007

Location	USA and Canada, August 15, 2003, afternoon.
Description of events	During the morning, voltages in Northern Ohio area began decreasing due to the large import and high conditioning load. Efforts to maximize reactive output and support the voltages caused a 600MW/400 Mvar unit near Cleveland to trip at 13:31. Unfortunately, the operators were unaware of a computer failure in the control centre and did not know that they essentially were operating blind. At 15:05, one of four 345 kV transmission lines connecting the Cleveland area to generation in the Ohio River Valley to the southeast tripped while being loaded at only 44%, because of a ground fault caused by conductors sagging. The trip of this line naturally increased the loading on the three remaining 345 kV lines. Half an hour later, a second 345 kV line tripped and nine minutes later, a third line tripped and locked out. All lines were within emergency ratings. At this point, many remaining interconnection lines (a 345 kV and several 138 kV lines) still in service were overloaded. Over the next 25 minutes, the 138 kV lines began sagging into underlying objects and tripping. At 16:05, the last 345 kV line tripped (zone 3 relay) and left Cleveland separated from the southeast. This resulted in a 1400 MW large “loop flow” and in significant overloads which soon led to additional line tripping. The system became transiently unstable, and many grid separations occurred in the following 15 seconds. The breakup resulted in five major islands, three of which (northern Ohio, eastern New York, and Ontario/eastern Michigan) soon collapsed and blacked out. The other two islands (New England/Maritime provinces and western New York) survived with some load loss.
Power before the incident	
Duration and Energy not supplied	62000 MW lost, 2 days
Geographical extension and people affected	50 million people
Type of SPS in operation	
Operation of SPS during the incident	
Economical quantification	4-10 billions $
Remedial actions after the fact	
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007 • J.D.McCalley, *operational defense of power system cascading outages.* IEEE PES T&D Conference &Exhibition, 2008. • I.Maldonado, *The performance of North American nuclear power plants during the electric power blackout of August 14, 2003.* Nuclear Science Symposium Conference, Oct. 2004.

Location	Southern Sweden and Eastern Denmark, September 23rd, 2003, 12:30.
Description of events	At 12.30, a unit a nuclear power plant started to lower its initial 1235 MW generation to around 800 MW due to internal valve problems in the feedwater circuits. As the attempts to solve the problems failed, the reactor was stopped; this was a standard contingency, and the system could handle this outage without any immediate serious consequence. The frequency was automatically stabilized slightly below the normal operating limit of 49.90 Hz, and therefore actions were initiated to raise the frequency. At 12.35 pm, a double bus fault occurred in a 400 kV substation on the western coast of Sweden, due to a mechanical damage in the vertical disconnector that was located in the bay between the two buses. With the joint broken, the vertical structure of the isolator collapsed and it fell to the side in the direction of the other parallel bus. Two 900 MW nuclear units are normally feeding their output to this substation over two radial lines, connected to buses that are operated separately. This fault was directly detected by the separate bus protection devices, immediately tripping the circuit-breakers for all incoming lines to both buses. The two nuclear units with a total output of 1750 MW were tripped and that the grid lost its transmission path along the west coast. Initially this triggered heavy power oscillations in the system, very low voltages and a further drop in frequency down to a level slightly over 49.00 Hz, where underfrequency load shedding schemes start to operate. The grid was then heavily overloaded and also low voltage appeared. During some 90 seconds after the bus fault the oscillations faded out and the system seemed to stabilize, the demand recovered gradually by action of the numerous tap-changers. This lowered the voltage further on the 400 kV grid down to critical levels. Finally the situation developed into a voltage collapse. The grid split up into two parts. The southern part, comprising south of Sweden and eastern Denmark, initially remained interconnected but then collapsed. The second area was intact including the interconnections to Norway and Finland.
Power before the incident	Around 15000 MW.
Duration and Energy not supplied	Load initially lost: 4500 MW in Sweden and 1850 MW in Denmark. Energy not supplied: about 1 GWh. The complete restoration lasted about 8 hours.
Geographical extension and people affected	5 millions
Type of SPS in operation	Underfrequency load shedding
Operation of SPS during the incident	
Economical quantification	
Remedial actions after the fact	Further development of new operational planning procedures and new protection schemes.
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007 • J.D.McCalley, *operational defense of power system cascading outages.* IEEE PES T&D Conference &Exhibition, 2008.

Location	Italy, September 28th, 2003, 3.01.
Description of events	The first three events occurred in the Swiss grid: due to a tree contact, at 3:01:22 am the 400 kV line Mettlen-Lavorgo tripped; the automatic and manual re-closures failed due to the large phase angle across the breaker (42°). The trip caused the power flow in the serial tie-line Lavorgo-Musignano to drop from 1250 MW to 550 MW and the overload of the Swiss parallel lines Sils-Soazza (400 kV) and Mettlen-Airolo (230 kV). The Swiss coordinator ETRANS had only 15 minutes available to relieve the overload. ETRANS operators tried some topological countermeasures and at 3:11 asked The Italian TSO, GRTN for a 300MW import reduction, which took place in the following 10 minutes. However, the mitigation attempts did not relieve the thermal overload of the Sils-Soazza line. As a result the continuing sag of the line resulted in tree contact, at 3:25:22 and subsequent tripping of that line. This then caused the cascading trips of all the tie-lines in the north of Italy, except for a weak connection to Slovenia After the disconnection, Italy experienced a total power deficit of about 6800 MW and frequency continued to decline. First, the pumped storage (if in operation) power plants and some industrial loads were disconnected (starting at 49.6 Hz); then, starting at 49.1 Hz, the domestic customers automatic load shedding plan progressively took place, with the goal of preventing frequency from dropping below 47.5 Hz. This limit is the threshold under which generators are allowed, after 4 s, to disconnect from the grid, according to the grid code. Unfortunately, the load disconnected by the defence plan was not enough to stop the frequency decreasing; the situation was exacerbated by unexpected generators tripping during the transient period. At 3:28, when the frequency dropped below 47.5 Hz, the Blackout was unavoidable.
Power before the incident	27.4 GW (included 3400 MW of pumps)
Duration and Energy not supplied	24 hours, 180 GWh
Geographical extension and people affected	Italy, 55 million
Type of SPS in operation	Underfrequency load shedding, based on frequency and its time derivative. Additionally, the defence plan at first tried to avoid the separation from the UCTE system but then later tried to shed load and prevent a blackout, in case separation occurred.
Operation of SPS during the incident	A total amount of 7700 MW of load and 3200 MW of pumps were disconnected. A larger amount of load shed was expected.
Economical quantification	
Remedial actions after the fact	Complete updating of the defence plan.
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007

Location	Western Norway, February 13rd, 2004, 13:59
Description of events	At 13:59 on Friday 13, February a 300 kV line split up in a line joint. The line split was at first sensed by the distance protection as a high impedance fault, and therefore the breakers did not disconnect the line immediately. The fault was also seen by the distance protection on another 300 kV on the same interface: when the fault current increased, both lines in the corridor were tripped after the time delay of the relays. The remaining 300 kV connection experienced a 50% overload. With decreasing voltages and increasing currents, this line also tripped and the whole area collapsed.
Power before the incident	
Duration and Energy not supplied	Duration 1 hour, Energy not supplied: 1200 MWh
Geographical extension and people affected	500000 people
Type of SPS in operation	Underfrequency load shedding, not involved in the phenomenon
Operation of SPS during the incident	
Economical quantification	
Remedial actions after the fact	
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007

Location	Greece, July 12th, 2004, 12:12.
Description of events	At 7:08 of July 12, a unit of a power station in the Athens area was lost due to auxiliary failure. After repairing the unit was not synchronized until 12:01. At that point load had peaked to 9160 MW and voltages in the Athens area were depressed (0.9 pu) as long as the above mentioned unit was out of service. During the synchronization, however, at 12:12, the unit was lost again due to high drum level. This brought the system to an emergency state. At 12:25 a manual load shedding of 80 MW was performed, but the voltage decline did not stop and thus the TSO required a second manual 200 MW load shedding; however, this command did not have the time to be executed. At 12:37 another Unit 3 serving the weak area of Central Greece tripped automatically (unclear event) while the last unit in the same power station was manually tripped. After that, voltages collapsed and the opening of the North-South 400 kV lines, due to undervoltage (0.75 pu) relays caused the system splitting at 12:39. After that, all the remaining generation in the areas of Athens and Peloponnese were disconnected by undervoltage protection, leading to the blackout. The split of the system saved the North and Western parts of the Hellenic system.
Power before the incident	9320 MW (peak load)
Duration and Energy not supplied	In 1 hour, restoration of 1900 MW; all customers supplied at 17:30. 4500 MW lost.
Geographical extension and people affected	5 million people
Type of SPS in operation	No automatic protection scheme in operation, at least against voltage problems. Only manual load shedding.
Operation of SPS during the incident	
Economical quantification	
Remedial actions after the fact	In particular, load shedding will be automated, so that it is applied directly from the Control Center. Voltage Security Assessment should be applied on-line in the Control Center for a continuous voltage monitoring.
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007

Location	Australia, August 13th, 2004. 21:41.
Description of events	At the time of the incident, a current transformer at a power station, located at a large generation centre some 200km north of the major load centre of Sydney, developed an internal fault causing it to later explode. The line protection operated correctly to clear the fault. Fifteen seconds later the line re-closed onto the fault again and subsequently tripped and locked out as a result. At this point three of the four generating units at a close power plant tripped as a result of generator differential protection, with subsequent loss of 1971 MW and another generating unit commenced shutdown sequence initiated by negative phase sequence protection. The frequency fell rapidly to 48.9 Hz, but the automatic underfrequency load shedding (UFLS) was able to stop the phenomenon. However, another generating unit tripped 542 MW, 27 seconds after the fault, as a result of Automatic Voltage Regulation protection. Finally, 36 seconds into the fault, another 150 MW was tripped by a unit as a result of underfrequency protection. This resulted in further UFLS operation. A total 3087 MW of generation was lost at a time when the demand was 22629 MW.
Power before the incident	22629 MW
Duration and Energy not supplied	1535 MW, 7% of total load.
Geographical extension and people affected	
Type of SPS in operation	Under frequency load shedding
Operation of SPS during the incident	Most of the UFLS operated as designed. About 420 MW of load did not shed as expected, but this did not have an adverse affect on the UFLS performance. As a result of the load shedding and Frequency Control Ancillary Service (FCAS), system collapse was averted.
Economical quantification	
Remedial actions after the fact	Review of underfrequency load shedding should be undertaken to try to ensure equitable sharing of UFLS amongst regions.
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007

Location	Malaysia, January 13th, 2005, 12:16.
Description of events	The opening of a 275 kV bus section circuit breaker caused the adjacent 275 kV bus section circuit breaker to trip on overcurrent and the substation split into a north and south section. The north section experienced heavy loading. Heavy flow was also seen on the 275kV line that tripped due to the inter-trip scheme to protect it. Unfortunately with the above mentioned substation split, the loading on the remaining circuit caused it to trip and as a result power swung on to the parallel 132 kV network which also tripped out. Just after this event, the North–East and the Central–South sub systems began to pull apart. The weak interconnections and the high power flow gave rise to “pole slipping” condition which finally caused the North/East and Central/South Sub systems to split. This resulted in the unbalancing of subsystems : in the North-East subsystem, frequency raised 51.36 Hz before settling down to slightly above 50.5 Hz. In the Central-South Subsystem, frequency decayed rapidly. Following a temporary recovery initiated by underfrequency load shedding (UFLS), frequency rapidly fell below 47.5 Hz and the Central/South subsystem collapsed when all remaining generators tripped out. This was caused because a number of combined cycle gas turbine generator units tripped for various reasons (not due to generator underfrequency protection, normally set at 47.5 Hz). This premature tripping of the generator units caused a imbalance larger than the design capacity of the UFLS.
Power before the incident	11260 MW
Duration and Energy not supplied	4059 MW shed, 3 hours
Geographical extension and people affected	
Type of SPS in operation	15 stages of UFLS scheme from 49.5 Hz to 48.1 Hz.
Operation of SPS during the incident	The UFLS operated as expected.
Economical quantification	
Remedial actions after the fact	
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007

Location	Pakistan, September 24th, 2006
Description of events	The initial total demand of WAPDA was about 12 GW, supplied for 53% by hydro plants. At that time one of the three 500 kV transmission lines was in maintenance. The remaining two 500 kV lines were loaded close to their stability limits (about 1100 MW each). Moreover, a transformer in a power station was loaded at 94% of its capability. At 13.43, a transformer tripped due to a misoperation of a relay. The other transformer in the substation was overloaded and tripped. A cross trip also disconnected a 2120 kV line resulting in a 220 kV island separated in the north of the Country. This caused a significant change in the power flows on the 500 kV and 220 kV lines. In particular, the two 500 kV lines reached 1600MW and tripped. This caused a collapse in 10 s due to both voltage and small perturbation instability.
Power before the incident	11160 MW
Duration and Energy not supplied	
Geographical extension and people affected	
Type of SPS in operation	
Operation of SPS during the incident	
Economical quantification	
Remedial actions after the fact	
References	M.W.Younas, S.A.Qureshi, *Analysis of Blackout of National Grid System of Pakistan in 2006 and the Application of PSS and FACTS Controllers as Remedial Measures*. International Conference on Electrical Engineering, 2007. April 2007.

Location	UCTE system, Europe, November 4th, 2006, 22:10
Description of events	On 18 September 2006, a shipyard sent a request to E.ON Netz for a disconnection of a double circuit 380 kV line Conneforde-Diele on 5 November at 01:00. After N-1 analyses, E.ON Netz provisionally approved the request of the shipyard. On 3 November, the shipyard requested E.ON Netz to advance the disconnection of the line by three hours, to 4 November at 22:00. At 21:39, E.ON Netz switched off the two circuits of the 380 kV line and received several warning messages about the high power flows on the lines Elsen-Twistetal and Elsen-Bechterdissen. The problem was originated by a misunderstanding among the TSOs about the setting of the protections on the line Landesbergen-Wehrendorf (an interconnection line between E.ON Netz and Amprion TSO). Between 22:05 and 22:07, the load on that line increased by 100 MW exceeding the warning value of 1795 A. E.ON Netz made an empirical assessment of corrective measures but the control action put in place at 22:10 led to a result which was contrary to what dispatchers expected; the current on the line increased by 67 A (instead of decreasing) and the line was automatically tripped by the distance relays due to load encroachment. This tripping led to cascading line trips throughout the UCTE system due to load encroachment that triggered distance protection. The UCTE system was split in three unbalanced areas. As about 9500 MW came from the East area to the Western area before the separation, the frequency dropped at about 49 Hz in the latter area. On the contrary, in the North East area the frequency reached about 51.4 Hz . The South East area had a power deficit of around 800 MW which induced a slight under-frequency of about 49.7 Hz. Defence plans were activated in each TSO area and led to automatic load shedding and pump storage units. The defence plan actions triggered by each TSO helped to restore the frequency close to its nominal value in relatively short time.
Power before the incident	274 GW
Duration and Energy not supplied	Restoration in 20 minutes, re-synchronization in 38 minutes, normal operation in less than 2 hours. 14.5 GW lost.
Geographical extension and people affected	Europe, 15 million
Type of SPS in operation	Underfrequency load shedding based on frequency and on its derivative. For every TSO, the general rule is to trip the pumped-storage units when the frequency drops to 49.5 Hz and to start the automatic load shedding step by step at a frequency near 49 Hz with thresholds every 0.4 Hz or 0.5 Hz.
Operation of SPS during the incident	About 17000 MW of load and 1600 MW of pumps were shed, more than the initial imbalance (9000MW) because of the tripping of some generation units during the transient. In some control areas (Italy and Austria), the automatic load shedding was complemented by additional manual load or pump shedding due to the low stable frequency near 49.2 Hz a few minutes after the incident. Due to the adequate performance of the automatic counter-measures in each individual TSO control area and additional manual actions by TSOs a few minutes after the splitting, a further deterioration of the system conditions and a Europe wide black-out was avoided.
Economic quantification	
Remedial actions after the fact	Better coordination of UCTE TSOs
References	• IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007 • J.D.McCalley, *Operational defense of power system cascading outages.* IEEE PES T&D Conference &Exhibition, 2008. • C.Li, Y.Sun, X.Chen, *Recommendations to improve power system security: lessons learned from the Europe bleackout on November 4.* UPEC 2007. • *X.Chen, C.Deng, Y.Chen, C.Li, Blackout prevention: anatomy of the blackout in Europe.* 8th International Power Engineering Conference (IPEC 2007).

Location	Florida (USA), Tuesday, Feb. 26, 2008, 13:08.
Description of events	The incident was started by the disabling of two levels of relay protection in order to diagnose a relay malfunctioning, without authorization and contrary to security procedures. During the diagnostic process, a fault occurred, with the loss of about 2300 MW of load in South Florida and, because both levels of relay protection had been removed, caused an outage ultimately affecting 26 transmission lines and 38 substations at the 138 kV level. Consequently two nuclear generation units, as designed, automatically and safely shut down due to an under-voltage condition, and eventually a frequency oscillation occurred that lead to the total loss of approximately 4300 MW of generation capacity. This caused the operation of the first (over nine) step of the underfrequency load shedding scheme that shed about 2200 MW of load.
Power before the incident	
Duration and Energy not supplied	66% of disconnected load restored in 60 minutes, 90% in 1 hour, 100% at 16:30.
Geographical extension and people affected	584,000 (13% of customers)
Type of SPS in operation	Underfrequency load shedding
Operation of SPS during the incident	Shedding of 2200 MW, according to the design
Economical quantification	
Remedial actions after the fact	Changes in relay maintenance, review and update of the defence scheme
References	https://www.frcc.com/Reliability/Shared%20Documents/FEAT%20Interim%20Report.pdf

Location	Great Britain, May 27th, 2008, 11:34.
Description of events	On the 27th May 2008, before the event, the day's forecast demand and generation levels were recorded as being healthy and not at all unusual. An unrelated and near simultaneous loss of generation at Generator A (345MW at 11.34am) and Generator B (1237MW at 11.36am), totalling some 1582MW, gave rise to a drop in system frequency to 49.14Hz, resulting in a major system disturbance. About 2 minutes later, there was a further as yet unexplained loss which led to a drop in system frequency to 48.795Hz. In order to prevent wider-scale losses of supply, a number of automatic low frequency relays operated at 48.8Hz to arrest the fall by disconnecting some 581MW of demand (estimated as some 580,000 customers). The system frequency recovered, and Distributors could restore most of the load within 40 minutes, though some customers took up to 63 minutes. Demand control was applied throughout the afternoon and over the evening peak, as a result of which normal operating margins were re-established by early evening.
Power before the incident	About 42 GW
Duration and Energy not supplied	After 2 minutes, instructions were given to the affected Distributors to restore automatically disconnected load. All customers were supplied after 63 minutes. Energy not supplied is estimated at less than 290 MWh.
Geographical extension and people affected	580,000 people
Type of SPS in operation	Underfrequency load shedding (60% of the load at the distribution level, in 9 blocks), starting at 48.8Hz
Operation of SPS during the incident	581 MW of load shed (first stage) although it seems that not all the devices operated successfully. However, total blackout was avoided and the frequency was recovered in 9 minutes.
Economical quantification	
Remedial actions after the fact	Still under definition at time of writing.
References	National Grid, "Report of the investigation into the automatic demand disconnection following multiple generation losses and the demand control response that occurred on the 27th May 2008", available http://tinyurl.com/GBMay27event

2.3 Features of major unreliability events

2.3.1 Interaction of phenomena

The process of system collapse is closely related with the physical nature of large synchronously interconnected transmissions systems. In this respect power system instability phenomena like transient instability, small signal instability, system voltage instability and frequency instability play a crucial role. (For definitions of stability phenomena, see for example, [1],[2]). Past incidents have shown that these stability phenomena often occur consecutively or simultaneously. They are often blurred, interactive and not clearly delimitable.

In many cases a disturbance was followed by an initial post-disturbance period during which the power system remained intact [3]. However, if a disturbance is not dealt with promptly, the uncontrolled post-disturbance phenomena will continue to pervade the power system and will actuate responses from control devices like turbo-generator governors, automatic voltage regulators, boiler-controls, tap changers, protection devices etc.. These devices function at different speeds and possibly without being coordinated with each other, which could finally lead to a "domino effect" and the loss of stability if a critical point is passed.

2.3.2 Maintaining the operation of generators

For the avoidance of blackouts it is therefore vital to diminish the post-disturbance phenomena and to keep voltages, currents and frequencies within their acceptable limits, which is a precondition for reaching a stable operating point. To reach a stable operating point it is a precondition in turn to ensure that the generation units keep on running.

In the end, the challenge of avoiding total system blackouts is more or less the challenge of keeping the generating units running (Figure 2.1). A number of the events described above have shown, among other things, that the risk that arising from asynchronous operation is highly related to an emerging voltage collapse when partial systems begin to drift apart with respect to their phasors. In the electrical centre the voltage drops to zero which might result in the tripping of units with an advanced deterioration of voltage support and consequently with the cascade tripping of further units and/or lines. In order to avoid these ravaging effects, in the course of an event, parts of an interconnected power system that begin to loose synchronism have to be isolated from each other as quickly as possible. Furthermore, it must be ensured that generating units remain synchronised and operational wherever possible. For example, in the Italian event of 2003, the tripping of a number of power plant contributed to the collapse of the Italian system after separation from the rest of Europe. The reasons for these trip events included low system frequency, blocking of turbines, loss of synchronism and, in the case of the station at Montalto, low voltage.

The possibility of generation tripping earlier than necessary raises the importance of compliance of generating plant with the performance required of them in grid codes. (This is discussed further in section 6 below).

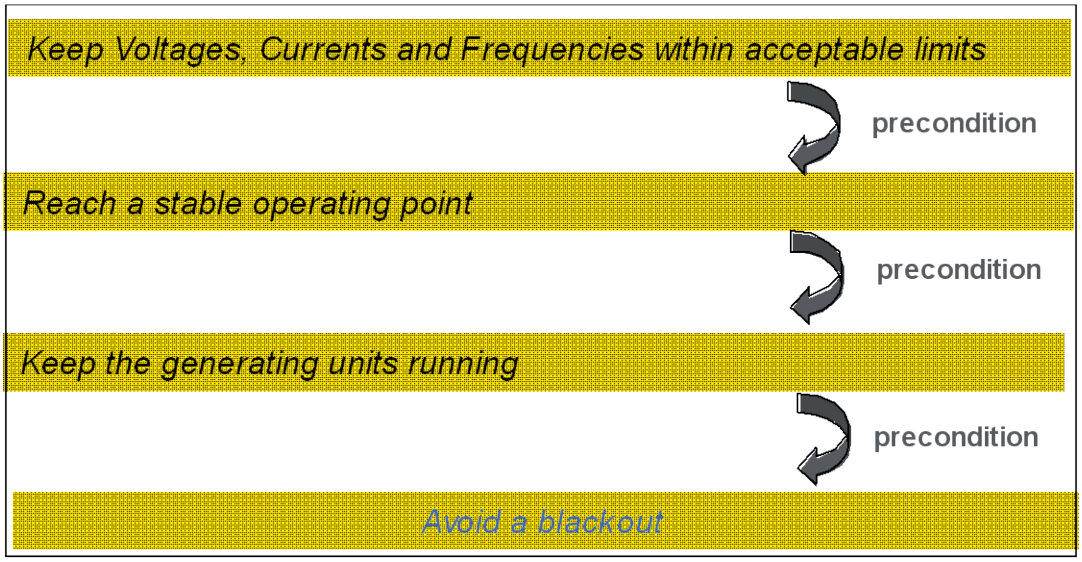


Figure 2.1: Main conditions to avoid system blackouts

2.3.3 The influence of line protection

The following examples shall briefly illustrate how the behaviour of line protection influences the course of an event. The 28 September 2003 Italian blackout was triggered by a trip of a 380 kV line between Switzerland and Italy caused by tree flashover (Figure 2.2) [4]. Due to its proximity, another 380 kV line between Switzerland and Italy was overloaded, which was acceptable only for a short time period. An import reduction (at this time Italy was importing around 6400 MW) together with some internal countermeasures taken within the Swiss system was insufficient to relieve the overloads so that the second 380 kV line also tripped after a tree flashover (probably caused by the sag in the line, due to overheating of the conductors). After the loss of two important lines, a large phase shift on the remaining lines was created which led to an almost simultaneous and automatic trip of the remaining interconnectors towards Italy (most of them due to zone 1 and zone 2 distance protection). The Italian system was isolated from the European Network about 12 seconds after the loss of the second 380 kV line between Swiss and Italy. During these 12 seconds of very high overloads, instability phenomena had started in the affected area of the system. During the deceleration of the Italian voltage phasor, the Italian grid suffered an unsatisfactory low voltage level in northern-western Italy. After the tripping of all interconnections to UCTE the voltage settled back to near its nominal value, but frequency instability and the blackout in Italy was no longer avoidable: the loss of several generation units plus the loss of few thousands MW of import was, in spite of under frequency load shedding, not manageable by the system.

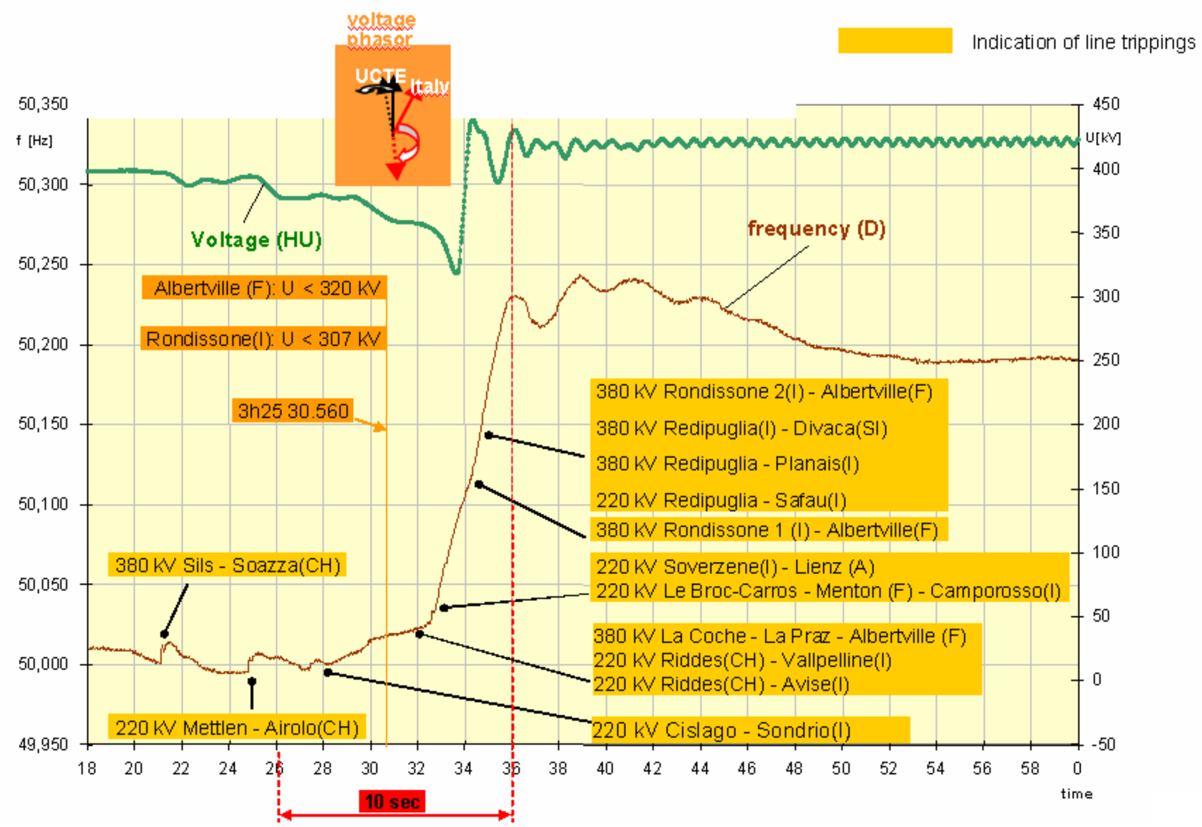


Figure 2.2: Line trippings in the course of the Italian blackout 2003 [4]

Unless out of step protection relays or other sophisticated system splitting schemes are installed in the power system the line protection system can act in this respect somehow as a “natural system protection” provided that the actual settings lead to a separation in due time. The separation prevented the rest of the European system from major adverse impacts, but it was obviously too late to avoid the collapse in northern Italy.

On 4th November 2006, the UCTE power system was affected by another severe incident [5]. The incident led to the splitting of the UCTE power system into three parts. The splitting took place rapidly so that the system did not suffer a voltage collapse. After the split, under-frequency load shedding operated successfully so that incident in fact led to major customer interruptions, but in a controlled manner so that the incident did not end up in a blackout.

One can argue that if the cascade line tripping had been avoided, losses of supply in both the Italian Blackout and the 4th November incident could have been avoided. On the other hand, once instability phenomena are under way, the parts of the interconnected network that tend to suffer the loss of synchronism have to be isolated rapidly. In densely meshed systems without distinct load and generation centres it is hardly possible to predict where the electrical centre will be located, which makes an optimal placement of system splitting schemes difficult. Especially under these conditions the line protection systems can therefore function as natural system protection.

Figure 2.3 shows another example of how system separation can contain a disturbance. In May 2007 a double busbar failure in the 380 kV substation at Wilster in Germany occurred which led to the disconnection of all 380 kV lines emanating from there. As a consequence, Denmark and the area north of Hamburg were connected to the rest of Germany solely connected by two 220 kV lines. Due to the weak interconnection an inter-area oscillation with increasing amplitude occurred. The protection relays which were being periodically excited during the oscillations finally tripped the 220 kV lines after 28 seconds and, in all probability, prevented the system from more severe consequences.

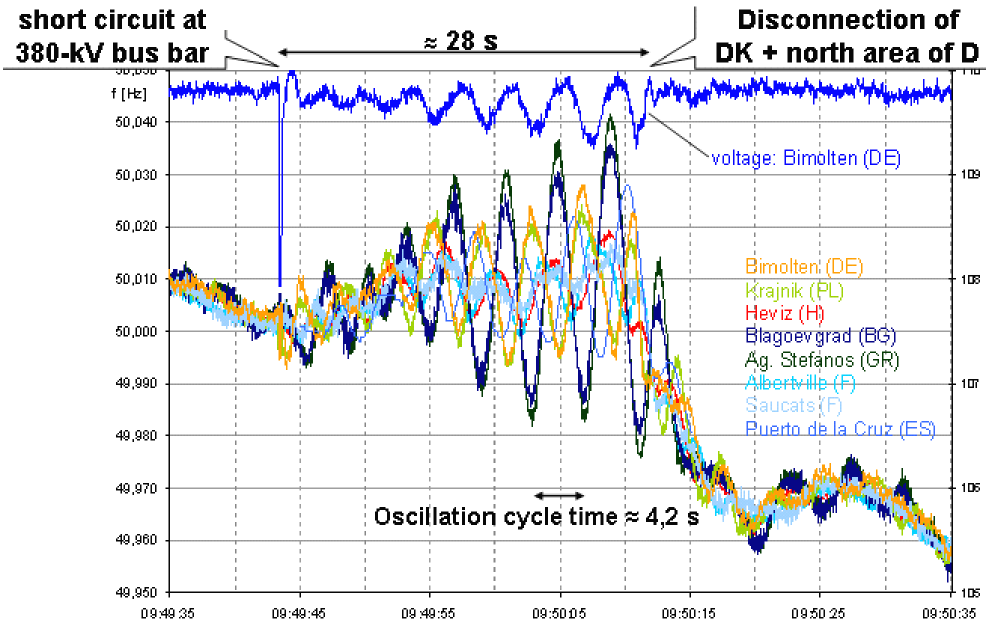


Figure 2.3: Interarea oscillations after a double busbar fault in Germany

The purpose of this Brochure is not to assess a certain line protection philosophy but rather to raise awareness of some key considerations. The fundamental and intentional task of line protection is to isolate faulted elements, e.g. in case of short circuits. An unintentional function of line protection systems is to act as a natural system protection under certain circumstances. This has to be kept into mind when specifying the protection philosophy, e.g. when discussing over-current protection or power swing blocking issues (for more information, see [6]). Chapter 6 provides additional information on the impact of protection systems on contributing to and managing major unreliability events.

2.4 References

[1] Prabha Kunder et al, “Definition and classification of power system stability”, *IEEE Trans. on Power Systems*, vol. 19, no. 2, May 2004.

[2] Prabha Kundur, *Power System Stability and Control*, McGraw Hill, 1994.

[3] CIGRE Task Force C2.02.24, *Defense plan against extreme contingencies*, Technical Brochure 316, CIGRE, April 2007

[4] UCTE, *FINAL REPORT of the Investigation Committee on the 28 September 2003 Blackout in Italy* – see http://www.ucte.org/pdf/News/20040427_UCTE_IC_Final_report.pdf

[5] UCTE, *Final Report System Disturbance on 4 November 2006*, – see http://www.ucte.org/pdf/Publications/2007/Final-Report-20070130.pdf

[6] IEEE, Power System Relaying Committee WG D6, *Power Swing and Out-Of-Step Considerations on Transmission Lines*, July 2005.

2.5 Further reading

- Andersson, G.; Donalek, P.; Farmer, R.; Hatziargyriou, N.; Kamwa, I.; Kundur, P.; Martins, N.; Paserba, J.; Pourbeik, P.; Sanchez-Gasca, J.; Schulz, R.; Stankovic, A.; Taylor, C.; Vittal, V., "Causes of the 2003 major grid blackouts in North America and Europe, and recommended means to improve system dynamic performance", *IEEE Transactions on Power Systems*, vol. 20, no. 4, Nov. 2005, pp. 1922-8.
- Vournas, C.D.; Nikolaidis, V.C.; Tassoulis, A.A., "Postmortem analysis and data validation in the wake of the 2004 Athens blackout", *IEEE Transactions on Power Systems*, vol. 21, no. 3, Aug. 2006, pp. 1331-39
- IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007
- CIGRE Working Group C1.2, *Maintenance Of Acceptable Reliability In An Uncertain Environment*, Technical Brochure 334, CIGRE, December 2007

38

3 Power System Security

Fundamental to the reliable supply of electricity and the prevention and containment of major unreliability events is the concept of power system security that is used by both planners and operators to identify when they must take action and what form it must take, and when no action would seem to be required.

This Chapter provides an overview of the concept of power system security and places it in the context of major unreliability events. Normally, because ‘security’ requires that no unduly adverse consequences arise from the events that are secured against, it might be assumed that only unsecured events – those events that, in accordance with statutory rules, require no specific action by operators – lead to major interruptions to the supply of power to consumers. However, as will have been seen in the summary of past major unreliability events in Chapter 2, this is not the case. This chapter therefore goes on to consider some refinements to concepts of security that might clarify the risks associated with events that are nominally secured against and also suggests that other sorts of events should also be considered when operating the system.

3.1 Definitions of security

An electric power system consists of closely interacting subsystems: generation, transmission and distribution, the combined effect of which should satisfy demand for power while respecting the operational limits – maximum and minimum loading and voltage – on the many components of each of the subsystems. Furthermore, the overall system should be stable.

The power system as a whole is said to be ‘adequate’ when demand is met and the various system limits are respected. Alternatively, ‘adequacy’ of a power system is defined in [1] as:

> *The ability of the power system to supply the aggregate electric power and energy requirements of the customer at all times, taking into account the scheduled and unscheduled outages of system components.*

The definition clearly points out that the system is always subject to disturbances to the network that limit its capacity to transfer power or to balance between generation and demand. Furthermore, it underlines the fact that there can be different degrees of adequacy measured in terms of the proportion of time in which it is adequate in respect of meeting demand.

The kinds of disturbances to the network include:

- internal failure of transformers, lines, switchgear, etc.;
- adverse weather conditions leading to short circuits on and subsequent trips of network components, especially overhead lines;
- failures of transformers, overhead lines or underground cables due to overloading;
- failure or unintended action of control and/or protection systems;
- failure due to sabotage.

In addition, at the moment of any one disturbance, parts of the network may already be unavailable due to previous failures or planned maintenance or construction outages.

Although failure events might have been influenced by inadequate maintenance or incorrect design or installation, they are largely out of the control of the system operator (SO). This is also true for disturbances of the system balance caused by

- generator failure;
- failure of power station subsystems leading to failure of generation;
- lack of fuel – including wind or water – or lack of cooling water capacity leading to generator ‘run-back’ (decrease of output);
- network maintenance or failure causing generator run-back;
- a sudden large change in demand, e.g. due to a connection failure or site process shut-down;
- smaller changes in demand due to variation in users’ behaviour, illumination, changes to weather, etc..
- variable power output from stochastic generation, such as wind and solar

In addition, generation facilities may be unavailable due to maintenance.

In the face of all the above and the social and economic importance of electric power, the ‘security of supply’ of power receives considerable attention from electricity users, regulators and policy makers and, as a consequence, system operators, transmission and distribution owners, and investors in generation.

Eurelectric’s definition of ‘security of supply’ is [2]:

> *the ability of the electric power system to provide electricity to end-users with a specified level of continuity and quality in a sustainable manner; relating to the existing standards and contractual agreements at the points of delivery.*

Due to the fact that both network and generation investments are expensive and time consuming, perfect ‘security of supply’ is not realistic. One of the key challenges for system operators, network owners, generation investors and operators, regulators and policy makers is the appropriate trade-off between investment in system facilities and ‘security of supply’.

The definition of ‘security of supply’ given above is a rather qualitative description. A quantitative appraisal can be achieved through calculation of the reliability of supply. The North American Electric Reliability Council (NERC) defines power system reliability as follows [1]:

> *Reliability, in a bulk power electric system, is the degree to which the performance of the elements of that system results in power being delivered to consumers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration and magnitude of adverse effects on consumer service.*

The reference in this definition to frequency implies, as in other areas of engineering, that ‘reliability’ is a probabilistic quantity and as such will be affected by the likelihood of the different disturbances within some period of operation from a given initial system condition. Another dimension is the magnitude of the possible adverse effects, and a number of indices of power system reliability have been defined to represent the overall level of risk to service in different timescales [3],[4].

In practice, electric power utilities have been accustomed to addressing ‘security’ rather than reliability, especially in operational timescales. ‘Security’ has a more tightly defined meaning than ‘security of supply’. For example, it is defined by NERC to be [1]:

> *The ability of the power system to withstand sudden disturbances such as electric short circuits or non-anticipated loss of system components.*

(Note that, in contrast with the aforementioned definition of adequacy, the customers are not mentioned).

This definition implies a need to consider all possible ‘sudden disturbances’. However, if any sort of generally acceptable level of ‘security of supply’ is to be provided to end users of electric power, the power system must be designed in such a way as to be operable with reserves of both active and reactive power and of network capacity. Thus, many ‘sudden disturbances’ will have little or no immediate adverse impact. In any case, many of them normally have a very low probability of occurring within some given time period.

A practical step to permit operational – or, in the longer-term, investment – decisions to be made in order to achieve satisfactory levels of security is to define different classes of security with respect to risk. Here, the risk associated with a disturbance is the product of the probability of its occurrence and the extent of its impact. Further classification may be made in respect of whether the overall integrity of the system can be sufficiently well protected by actions to correct adverse outcomes of disturbances or whether some preventive measures must be taken before any of the possible disturbances occur. A framework within which different states of security can be understood was suggested by Dy Liacco as long ago as 1967 [5] with a different version presented in [6] and reproduced in figure 3.1 below.

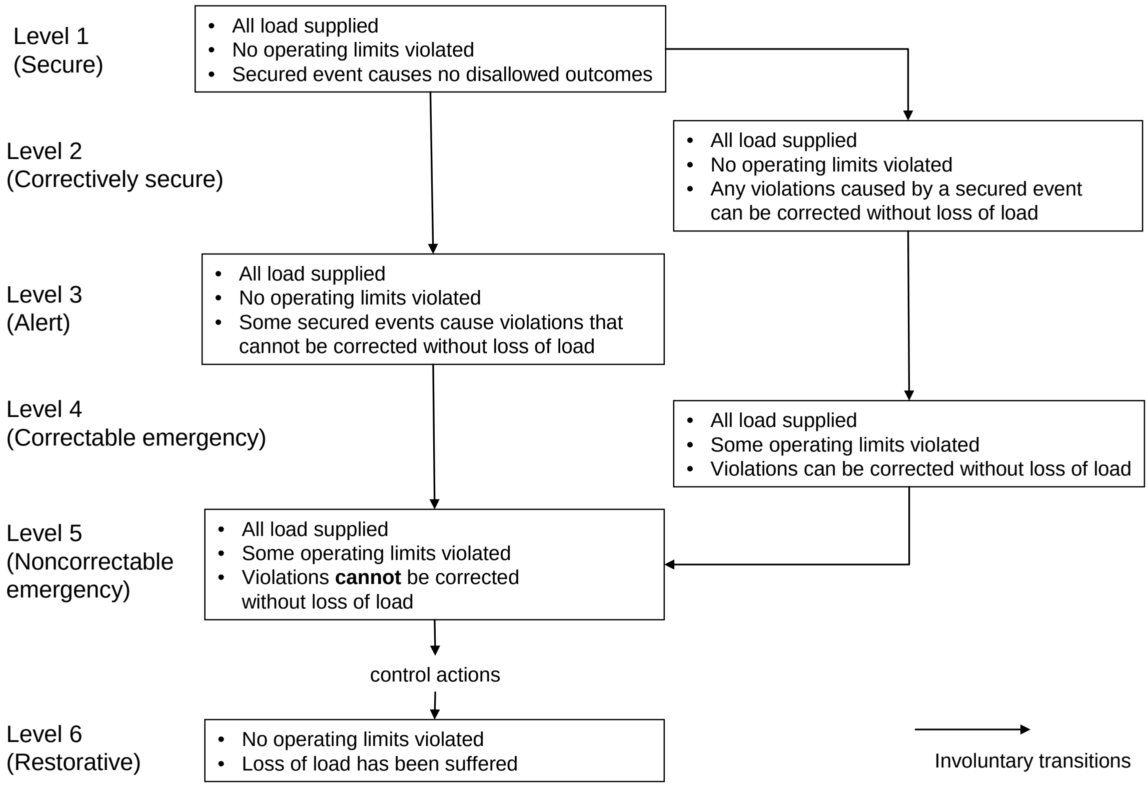


Figure 3.1: power system static security levels [6]

Because of the wide social and economic impact of power system failure, for many system operators, these considerations are formalised in security standards or ‘reliability standards’ [7] and an operator must take action to ensure continuous compliance with the standard. The key aspects of a standard are the ‘secured events’ (or ‘contingencies’) and the consequences to be avoided should one of them occur [8],[9]. A system that is operationally ‘secure’ is generally assumed to be one with a low probability of blackout.

The ‘secured events’ are conventionally defined in terms of N-k where N represents the initial state of the system and, depending on the convention used in the particular standard, k represents either a number of primary components going out of service or a number of events. Conventionally, the ‘secured events’ are those that are regarded as ‘credible’. In this regard a ‘secured event’ is a contingency or a fault which has been specifically foreseen in the planning and operation of the system.

The consideration of which consequences and events to prescribe in a standard is quite well illustrated in the RTE Reliability Handbook [10], reproduced in figure 3.2 below. It can be seen that some events are so significant in terms of their impact that they must be secured against. Another set has both relatively high probability of occurring and quite significant impact and so should also be secured against. Other events might be quite common but of lesser impact, and whether they should be secured against should be the subject of an economic appraisal. A final set of events is perceived as so rare that it would not be cost effective to secure against them.

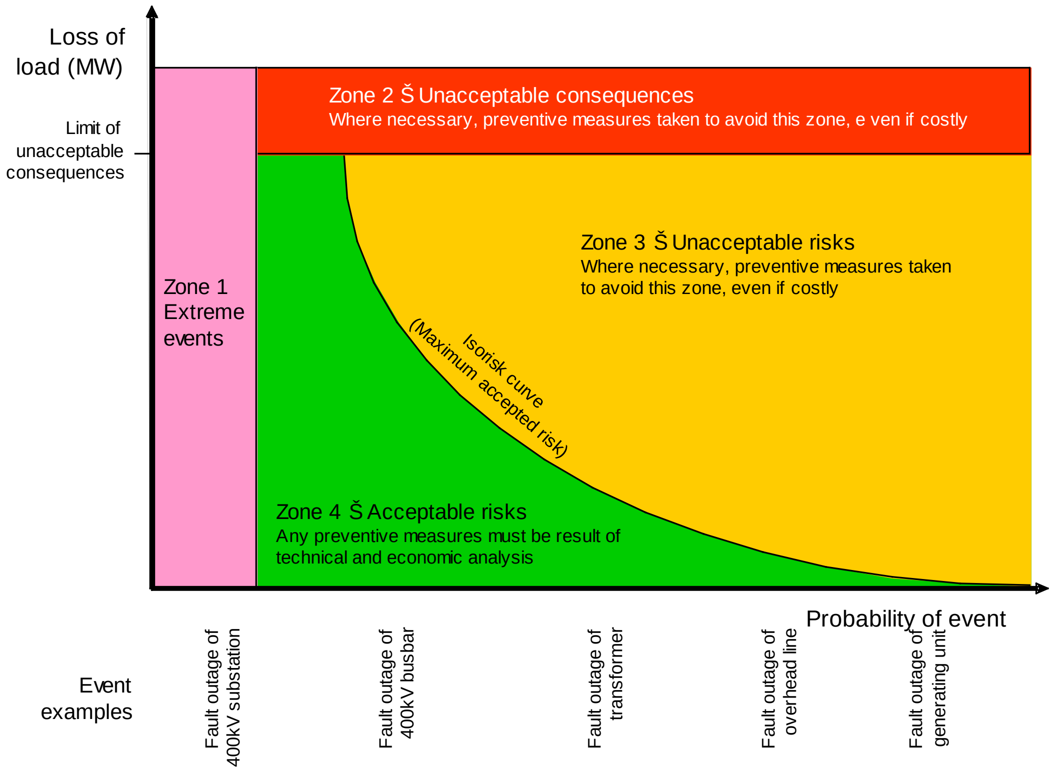


Figure 3.2: unplanned events, consequences and risks [10]

3.2 Risks of loss of load

In figure 3.2, it can be seen there are regions of the space in which corrective actions would have to be relied on to manage the impact of a disturbance. As in the figure, one dimension of the consequence is the extent of an initial 'loss of load', i.e. interruption to supply to end users of power[3]. Another dimension is the time for which some degree of loss of load persists.

The general mechanisms by which disturbances might lead to a loss of load are described in chapter 4, particularly in the context of 'major unreliability events'. As was noted in chapter 1, CIGRE WG C1.2 used the term 'major unreliability event' to distinguish interruptions of supply arising on the main transmission system and involving possibly quite complex interactions from those that arise from simple outages on connections to grid supply points [11]. A 'major unreliability event' ranges from a regional interruption through to a system blackout.

[3] In this dimension might also be included a consideration of the location of an interruption. That is, government or industry might view a disturbance to a city as being more significant than that to a similar load across a wide rural area. However, such views might not gain full acceptance among the general public.

Depending on the dynamics of a consequence, corrective actions to limit the extent of an initial loss of load might need to be implemented automatically; the facilities to achieve this may be broadly described as ‘defence measures’. ‘Restoration plans’ represent measures taken by a utility to minimise the duration of a loss of load and to enable the supply to be restored. Defence measures and restoration plans are addressed in chapter 4.

The remainder of this chapter will consider security standards in more detail along with what they imply for risks of loss of load and the need for investment. Based on the fundamental notions already expressed in some standards, a broader concept of security will also be proposed.

It has already been suggested that ‘risk’ might be quantified by means of the product of the probability of an event occurring or circumstance arising and a measure of the extent of its impact were it to occur. Some possible measures of impact include:

- the initial loss of load (in MW);
- the total energy not supplied (in MWh).

The latter must be estimated in terms of what the load would have been throughout the period in which it was not supplied and is, of course, heavily influenced by the rate at which load is restored. This might be converted into some monetary quantity by multiplying by a constant ‘value of lost load’ for each MWh of unsupplied energy or by an opportunity cost in terms of the ‘gross value added’ that is lost as a consequence of the interruption.

Monetary representations of the impact of an event are discussed further in Chapter 7. However, as was outlined in Chapter 1, some different classes of loss of load can be identified:

1. those that affect individual ‘grid supply points’ (a ‘local’ interruption);
2. those that affect an area of the system (a ‘regional’ interruption);
3. those that affect the whole system (a ‘system-wide’ interruption)).

As was noted in Chapter 1, the first of these is not the subject of this report as they are the most common and are usually associated with simple outage events on radial connections. Management of the frequency and extent of these events is a normal part of the design of connections.

The second and third categories – both of which might be termed ‘major unreliability events’ – generally involve more complex mechanisms and are often harder to manage. Moreover, without adequate responses, events that affect only an area of the system can easily affect the whole system.

Perceptions of ‘major’ in terms of the level of initially interrupted load are likely to vary from country to country or from system to system. For example, while standards in neither country use the term ‘major unreliability event’, interruptions above a threshold of 1500MW seem to be regarded as particularly significant in Great Britain (GB) while 600MW seems to be an important threshold in France. (See section 3.4 below).

3.3 Security standards and the need for investment

The standards of security employed in operational timescales not only dictate operational decisions and expenditure on ancillary services (such as frequency response and reserve), re-despatch of generation to manage congestion and so on, but also expenditure in investment planning timescales. As has been noted above, the cost of providing sufficient network and generation capacity to always – or almost always – guarantee that the system is adequate is excessively high. Hence, some judgement must be made about the required level. This usually concerns ensuring that sufficient facilities are available for the system to be operable in a secure manner for some (generally large) proportion of the external conditions that might reasonably be expected to arise. As was noted in Chapter 1, liberalisation of electricity markets and separation of responsibilities among many different parties makes, from the point of view of a system operator or transmission owner, the forecasting and management of these externalities more difficult than before.

As was observed in Chapter 1, this report is concerned with the responsibilities of a network utility, particularly a transmission owner (TO) or transmission system operator (TSO). In the above way, a notion of security in operational timescales plays an important role in determining investment by a TO or TSO in network facilities. However, as has also been noted in Chapter 1, this report is not concerned with 'classical' investment in network capacity, such as through additional primary plant like overhead lines, underground cables, transformers and substations. However, these are not the only investments for which a system planner has responsibility.

'Classical' investments are concerned with enabling secure operation (in accordance with however 'secure operation' is defined). The other investments suggested in the preceding paragraph would therefore seem to be concerned with circumstances that are not secured against.

A circumstance that is not secured against is

1. one for which the consequence has not been specified as unacceptable[4]; or
2. an initiating event that is not included in the list of 'secured events'.

By reference to figure 3.2, this essentially means zones 4 and 1.

Examples of the former can be found in the current GB 'Security and Quality of Supply Standard' (GB SQSS) [12]. One is the requirement that the loss of load as a consequence of a double circuit fault outage should not exceed 1500MW. However, the loss of *less than* 1500MW as a consequence of a double circuit fault outage *is* permitted except when it would be relatively inexpensive to avoid it or when the likelihood of a double circuit fault is high, such as during adverse weather.

Many engineers are accustomed to describing examples of the latter category of circumstances not secured against as 'extreme events'. These might be

1. a single event that is not secured against e.g. a single simultaneous fault outage of both sides of a double busbar (such as happened in Sweden in September 2003) [13] or an event outside the area of a system operator's jurisdiction that has an impact on the SO's own area;
2. a combination of independent events that, together, are not secured against and which occur within such a short period of time (relative to an operator's ability to respond) that they are effectively simultaneous – an example of this is the loss of more than 1500MW of generation infeed within 2 minutes in GB in May 2008 [14] (the biggest loss of infeed for a single event in GB is currently 1320MW and is the figure used to determine reserve requirements), or
3. a single, secured event that does not on its own lead to unacceptable consequences but sometimes can through a cascade of further outages so that it ends up as an 'extreme' event with unacceptable consequences.

Many would argue – probably quite correctly – that item 3 is not really an example of an 'extreme event' as the further outages are not actually independent of the first event. If the system – including the various protection and control systems – has been well designed and its parameters are accurately modelled, the circumstances under which a cascade might occur will be well-understood by the system operator. If they do lead to unacceptable conditions, the operator will be obliged under the standard to take action to prevent them from arising. This is because they are all a consequence of a single secured event. However, as was shown in Chapter 2, it is also understood that the complex

[4] By implication, it is 'acceptable' though system operators might not wish to spell that out.

dynamic trajectory of a system state may take it into a region in which further outages take place that are not normally expected.

If the complex case of item 3 is accepted as an example of an ‘extreme event’, all of the above three types of ‘extreme events’ are, in some sense, ‘outside’ of a security standard and would therefore not be expected to drive ‘classical’ investment in basic system capacity. They can and do occur and often lead to loss of load, the extent of which might be managed by defence measures and/or effective restoration.

A number of historic ‘major unreliability events’ have been examples of item 1 in the above list. Some of these, such as the Italian collapse in 2003, have been an event that has occurred outside a particular SO area but had major consequences for that SO. Another example of item 1 is where the unsecured event is ‘an operator makes a mistake’, or ‘a trade with a neighbouring market is higher than expected’. In addition, the item 2 in the above list could include an N-1 system event (that should be secured against) concurrent with a human error.

Can the above considerations, normally not addressed in security standards, be built into a wider ranging concept of security that, while not driving either ‘classical’ investment in network capacity or operator intervention through ancillary services or re-despatch, might drive investment in facilities for the containment of ‘extreme events’? The next section considers this question along with that of operational security standards that adapt their stipulations to the prevailing conditions; where those stipulations are relaxed, risks might be mitigated by the ‘containment’ facilities.

3.4 Towards a broader concept of security

In the previous section, it has been suggested that some broadening of the scope of a security standard might be useful. This would be with the aim of making the actions and responsibilities both of system operators and transmission planners clearer in respect of system risks, in particular those associated with ‘extreme’ events.

Two aspects are suggested for embedding in a new, broader concept of security that might be included in a standard. The first of these already finds use in some countries and is described here to enable readers from other places to learn more about it and decide whether it might also be appropriate in their context. The second is perhaps more innovative; it is described here only in outline and so would require more work for a robust implementation. In both, the notion of ‘risk’ is used where ‘risk’ is the product of the probability of an event or a circumstance and a measure of the impact of that event or circumstance.

3.4.1 ‘Adaptive’ security

The first aspect of a possible new concept of ‘security’ concerns what might be called ‘adaptive security’.

The main benefit of ‘adaptive’ security is that the procurement of additional ancillary services or restrictions to the electricity market need only be implemented when operational risks are high; alternatively, market restrictions and the volumes of ancillary services can be relaxed when risks are low. In most examples, while the expected consequences might remain the same, there is recognition that a particular risk can move laterally in the space described by figure 3.2 by virtue of the probability of an event changing[5].

[5] There will be ways in which the consequences of an event might change, depending on the overall state of the system and a complex set of interactions, but this is much harder to quantify.

Examples of ‘adaptive’ security can be found in the Netherlands, France, Australia and Great Britain.

In the Netherlands, for example, an action plan is put in place during prolonged periods of warm weather (characterized by limited power production due to the temperature of the cooling water) that consists of three different phases linked to the size of the reserve capacity. The last phase is invoked when the total size of the reserve capacity (with a dispatch time of up to 15 minutes) falls below 700 MW. In the event of an imbalance between supply and demand, the TSO can take a number of measures to restore the balance, with the aim of safeguarding the security of supply. In case of extremely critical problems, it may be necessary to disconnect part of the load to prevent a large-scale disruption.

In Britain, there is a general security rule for transmission system operation that a double circuit fault outage[6] should not cause the interruption of more than 1500MW of demand or ‘unacceptable voltage conditions’ affecting more than 1500MW of demand. However, when the likelihood of a double circuit fault outage is significantly higher than normal, the system should be secured against a double circuit fault so that there will be no overloading, system instability or unacceptable voltages, and, if the cost achieving it is not significant, the loss of demand should be no more than 300MW [12].

The above are examples of expressions of ‘adaptive security’ that are already used in the industry. However, they are rather qualitative in nature.

In Australia, reclassification of non-credible contingencies is utilised as an adaptive security measure. Under abnormal conditions the system operator, AEMO, may reclassify a non-credible contingency as a credible contingency. Once this is done AEMO would operate the system such that upon occurrence of this event (e.g. loss of multiple circuits) the system would remain satisfactory (i.e. there would be no significant risk of cascade failure). This process is set out in Clause 4.2.3A of the National Electricity Rules. Recently AEMO has increased the sophistication of its reclassification procedures particular as regards lightning and bushfire risks[7].

One of the challenges in this area has been both to quantify the risk associated with a current or planned operating state and also to be able to give sound advice to an operator on the most cost-effective means of modifying the risk prevalent at that time. Since the mid-1990s, a number of academics have tried to address at least the first aspect of this question and have made attempts to quantify risk in the operation of transmission systems. (In general, probabilistic assessment of power systems previously related only to planning timescales). The published work on the subject includes that in [16]-[21]. The aim in [19], for example, was that a computationally efficient procedure might allow one or more possible planned operating states, each of which is being considered by an operational planner, to be compared in terms of the overall risk. For example, one particular dispatch of generation, pattern of transmission maintenance outages, configuration of substations and setting of voltage targets might be ‘secure’ in accordance with the security standard but actually have within it a significant vulnerability to a regional or system interruption due to unsecured events. On the other hand, another initial state might be marginally ‘insecure’ but more resilient to unsecured events. According to the procedure, the latter plan would be preferred. However, as the weather changes, the risks change and the former might be preferred. In respect of the conventional meaning of ‘security’, this is an ‘adaptive’ approach that is based upon a quantification of reliability[8].

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[6] For the vast majority of circuit km in GB, two overhead lines share single towers. Typically, the GB transmission system experiences between 5 and 10 double circuit fault outages a year.

[7] These procedures are set out in Section 10 of the Power System Security Guidelines – see http://www.aemo.com.au/electricityops/3715.html

[8] As far as the members of Working Group C1.17 are aware, none of the ideas contained in these works have yet found their way into industrial practice. While part of the problem is likely to be the practical one of sufficiently fast, easy to use and robust software being available, part of it may also be down to the apparently open ended nature of the problem that would be set for an operator or an operational planner – there would be so many options, it would be difficult to know when the ‘right answer’ has been found. This is in contrast to conventional

There remains one “problem” with ‘adaptive security’: a residual risk can never be eliminated. Even if the probability of the initiating event is significantly lower during periods of relaxation, it is not zero and the consequences can still arise and should still be managed. Moreover, it is often difficult for a system operator to know, with confidence, what the probability of a particular event is at any particular moment. For example, while it is known that ‘adverse’ weather gives an increased probability of a fault outage on an overhead line, the operator may not know what the prevailing weather at some remote location is.

Another issue with ‘adaptive security’ in operational timescales is how it should be taken into account in investment planning timescales. That is, is investment in additional network capacity to enable the system to be operable driven by conditions under which the operational standard is tighter, when it is more relaxed or by some probability weighted combination of both?

3.4.2 A broader understanding of ‘secured events’

The traditional understanding of contingencies to be secured against, i.e. ‘secured events’, has been the unplanned outage of primary power system plant, such as a single circuit, a generating unit, a single item of switchgear, an item of reactive compensation equipment or, in some cases, a double circuit. However, it has been noted above that the system might be disturbed by two or more apparently independent events that happen within such a short time of each other that the system operator has no opportunity to take action after the first to restore security and so they appear, in effect, as one disturbance.

Other situations might arise unexpectedly and so appear as unplanned ‘events’ even if they do not arise suddenly. These might include demand or an inter-area transfer being higher than expected. Indeed, such circumstances might be compounded by a lack of visibility of the system. It could be argued that lack of operator awareness of a quite slowly developing situation until it was too late for it to be managed was a factor in the blackouts of the north-eastern United States and of Italy in 2003 and of the UCTE disturbance in November 2006. Such a lack of awareness might be due to lack of accurate measurements at a key location, failure of state estimation, key system states being only part of the ‘external’ model in a state estimator or a lack of online security assessment facilities, whether because of computer system failure or the facilities not having been provided in the first place.

The realisation that the system state, relative to its operational limits, is not what had been expected and a response to it might be too late to prevent some adverse outcome, perhaps triggered by another quite random event. This circumstance might broadly be thought of as an ‘event’, particularly when regarded by an operational planner preparing advice or operational measures the day ahead of real time.

A list of such additional events worthy of consideration might include some of the following:

- unplanned outages of primary plant outside of an SO’s area;
- a combination of the more frequently occurring unplanned outages of primary plant;
- a demand forecast error in combination with a secured unplanned outage;
- an inter-area transfer forecast error in combination with a secured unplanned outage;
- a ratings error (due, for example, to vegetation or adverse weather) in combination with a secured unplanned outage;
- a generator reactive power limit error in combination with a secured unplanned outage;
- ‘human error’ in combination with a secured unplanned outage.

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security standards in which the ‘problem space’ is quite narrowly defined. There is also a lack, as yet, of strong ideas coming from research on pointers for how a given operational plan could be improved in the sense of risk.

These additional events or *combinations* of events, when laid alongside consideration of their possible consequences, might lead to 'arming' of defence measures even if they might not be accepted as driving restrictions of market-oriented power transfers or the procurement of additional ancillary services. Perhaps more importantly, because they can be reasonably foreseen as requiring the arming of defence measures or simply because they represent risks of major unreliability events that should be contained, they serve to illustrate the need for and justify investment in making containment measures available.

3.4.3 Issues with a broader understanding of security

Those with a stake in the operation of a power system – not only the SO, but also electricity users, energy producers, regulators and government – will want reassurance that their interests are always being properly served. With transmission ownership and system operation being generally recognised as monopoly activities, at least within a particular geographical area, statutes with which the TO and SO must comply play an important part. This might present a particular issue in relation to 'adaptive' security: the need for it to be clear about exactly when 'tighter' or 'more relaxed' standards apply and what is the appropriate course of action when there is some uncertainty about the conditions prevailing in the proximity of critical power system plant. An operator will need to be able to be sure that they were justified in restricting market operation or that they had complied with rules if something has gone wrong[9].

Some of the broader notions are likely to be politically sensitive in that a competent utility would not wish to give public acknowledgement to the possibility of gross error in forecasts of demand or inter-area transfers, let alone human errors in system operation such as incorrect switching or re-dispatch of generation. On the other hand, it should be possible to point to the uncertainties inherent in forecasting of demand and cross-border trades, uncertainties in data concerning generator capability (see Chapter 6) and to inherent inaccuracies in parameter estimation for network equipment. If account is to be taken of these uncertainties in the broader understanding of security suggested above, statistics on such factors would need to be available to quantify the associated 'contingency'.

3.5 Containment of major unreliability events

It has been suggested above that to seek to guarantee avoidance of major unreliability events is unrealistic. Good industry practice would suggest that measures should nevertheless be taken to contain their impact when they occur. The sorts of measures that might be effective are often referred to under the heading of 'system defence' but require planning and investment before they can be made available to a system operator. The nature of these measures and their place in the wider context of 'Management' of power interruptions is outlined in Chapter 4.

It has been suggested above that some broadening of the concept of 'security' might permit the identification and justification of investment in containment facilities. Examples of other justifications for containment measures currently in place or planned in a few countries are described in Chapter 8.

3.6 References

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4 Management of Major Unreliability Events

4.1 Introduction

As was discussed in Chapter 3, a power system can be subject not only to 'credible' contingencies but also to non-credible or extreme contingencies. These are rare and often result from exceptional technical malfunctions, *force majeure* conditions or human errors. As well as being rare, extreme contingencies vary significantly with respect to their causes and consequences and thus are not currently specifically defined in the design and planning policies of most utilities [1]. Due to the physical nature of large synchronously interconnected transmission systems, extreme contingencies can be accompanied by the removal of multiple components, cascading of outages or loss of stability followed by widespread interruption to electricity users' supply or, in the worst cases, a system blackout. In view of the societal and economic impact of these 'major unreliability events', good industry practice and respect of the interests of electricity users suggests a need for adequate management not only of 'credible' events but also of these more extreme ones.

The management of extreme contingencies or major unreliability events comprises different layers, as illustrated in Figure 4.1.

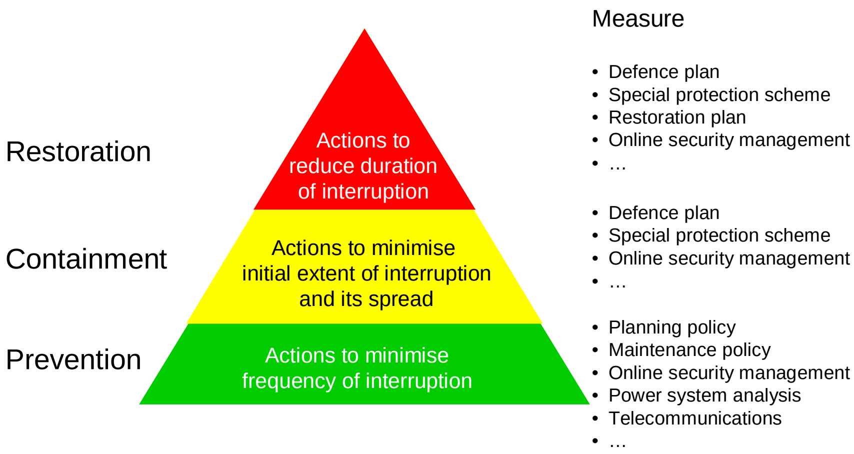

Figure 4.1: Management of major unreliability events

The **Prevention Layer** includes all actions and measures that aim to minimize the frequency of customer interruptions. The frequency of interruptions depends on decisions in all time frames of power system activity: system planning and development; the setting and implementation of maintenance policies; and the operation of the system. In general the frequency of interruptions in the wake of credible contingencies abates with increasing redundancy of primary equipment (e.g. additional transmission lines) and, for the same levels of power transfer, investments in transmission infrastructure improve performance with respect to interruptions.

As was discussed in Chapter 1, the changeover to a competitive market environment, large scale penetration of renewables, power plants not necessarily being built in optimal locations for system stability and system needs, geographical extensions of interconnected systems by the connection of new countries and finally the trend to operate systems closer to their limits entail enormous technical challenges and have caused and continue to cause changes in the way power grids are operated. Historically, isolated power systems were interconnected in order to form a "Backbone of security" through significant and reliable mutual help in emergency conditions. On the other hand the same physical characteristics can become more and more the "Achilles heel" of large synchronously interconnected power systems: the mentioned trends lead to soaring levels and distances of power transits which place the transmission system under increasing stress. The operation of the system closer to its (stability) limits leads to more severe consequences for the security of the system especially in case of extreme contingencies beyond the design criteria. In this way, what is perceived as a generally favourable overall physical coupling of previously independent systems implies the risk of carrying adverse effects to adjacent areas or even on the whole system and creates vulnerability to large scale blackouts.

From this result, the second layer, the **Containment Layer**, becomes more and more important. It includes all operational actions and measures that aim to minimize the initial extent of an interruption and in particular its unabated propagation throughout the system. The containment of extreme contingencies depends on the operation philosophy, the observeability and controllability of the system and the competence of operators. However, from a certain point, the containment of extreme contingencies is heavily dependent on the conceptualisation and successful operation of Defence measures. In this regard Defence measures build the last resort when a system collapse seems to be no longer avoidable.

Despite all prevention and containment measures, as has been shown in chapter 3, the past decades have provided evidence that major unreliability events occur. Therefore the **Restoration Layer** aims to reduce the duration of the interruption by reenergizing the backbone transmission system as fast as possible, which allows gradual reconnection of generating units and, subsequently, supply to customers. Prompt and effective power system restoration is essential for the minimization of downtime and costs to the utility and its customers, which mount rapidly after a system blackout [2].

Prevention, Containment and Restoration could be considered as the technical management of major unreliability events. In addition these events may require economic management, legal management, environmental management, information management (communication with customers), crisis management and so on. This report concentrates solely on the technical management and, so as not to repeat the work done by other working groups, in this context exclusively on containment and selected aspects of restoration. As the economic and social consequences of blackouts are so immense great importance has to be attached to the development and implementation of effective Defence measures and their justification to stakeholders.

The remainder of this chapter will present a brief summary of the main tools for Containment, in particular Defence measures, and describe some principles that underpin the formation of system restoration plans. Some case studies of containment measures are presented in Chapter 8.

4.2 Defence measures in the context of system states

As was described in chapter 3, the power system functions in terms of customer supply and scheduled power transits should not be affected within given limits by the predefined credible contingencies. To this aim the so called ‘N-1’ rule is common practice in most large power systems worldwide. The N-1 rule ensures that the power system is always operated in a robust condition with sufficient safety margins in order to withstand single fault events followed by the loss of one system element (transmission line, transformer, generating unit etc.). Under these circumstances the power system is considered to be in the “normal” state (Figure 4.2).

If the system parameters are still within admissible ranges but the system does not any more meet the criteria given for a secure state, i.e. it is no longer N-1 secure, the system is considered to be in an ‘alert’ state (or endangered state). Typically, the system reaches this state after a N-1 contingency. This state requires application of remedial actions without any delay in order to come back to the secure state, i.e. to comply again with the N-1 rule.

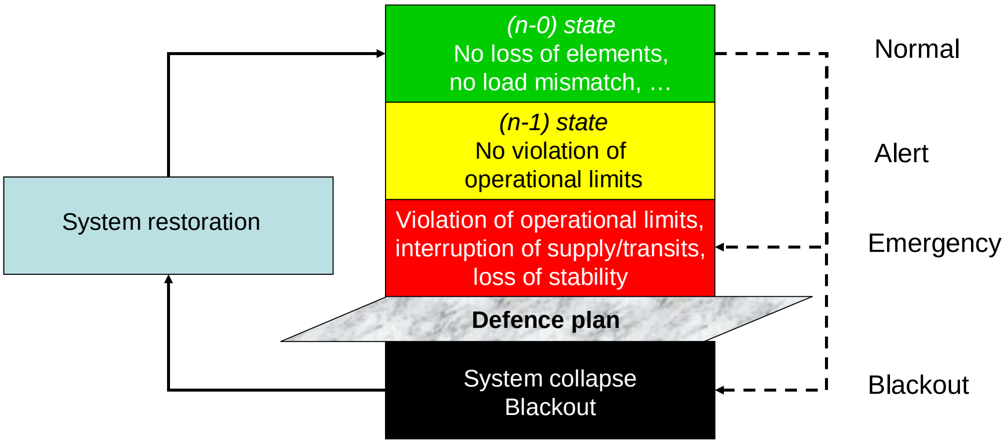

Figure 4.2: System States [3]

As a consequence of extreme or unforeseen contingencies, the individual variables that describe the overall system state could violate admissible operational limits and hence the system is considered to be in an 'emergency' state (a disturbed state). A system being in an emergency state might not be able to fulfil its function with respect to consumer supply and power transits, but is not blacked out. However, there is the risk of system collapse mainly due to the loss of stability. Therefore, relevant actions must be taken immediately to bring back the system into acceptable conditions.

In order to cope with and to minimize the impact of these rare but extreme contingencies, i.e. in particular to prevent a total system collapse, Defence Plans have been developed and implemented by many utilities. These plans include a set of coordinated and mostly automatic measures (System Protection Schemes (SPS)[10]) to ensure fast reaction to large disturbances and to avoid their propagation through the system. A Defence Plan is thus designed to initiate the final attempt at stabilizing the power system when a wide spread collapse is imminent [4]. Individual SPS such as load shedding, generation rejection or system splitting are then regarded as coordinated elements used within a Defence plan.

A 'blackout' state is characterized by almost total absence of voltage in a certain area of the transmission system as a consequence of tripping of generating units due to abnormal variation of voltage and/or frequency which occurred during the emergency state. Once the system enters the blackout state the restoration plan shall be activated as soon as possible (see section 4.5)

4.3 Defence measures in the context of stability phenomena

The risk of system collapse results from the possible loss of stability after extreme or unforeseen contingencies. Therefore, individual SPS used within a defence plan are generally designed to contain the different power system instability phenomena [5][2]:

- Rotor Angle Instability
- Frequency Instability
- Voltage Instability

Under normal conditions, and with sufficient automatic facilities, operators are generally able to adequately control power system operation. However, in the case of extreme contingencies the speed

[10] In the literature further notations for the term System Protection Scheme circulate, e.g. Special Protection Scheme (SPS), System Integrity Protection Scheme (SIPS), Remedial Action Scheme (RAS), Emergency Control Action (ECA). Independent of the respective notation, all these schemes are used when the focus for the protection system is on the power system supply capability rather than on a specific equipment.

and complexity of post-disturbance phenomena require specific fast automatic measures to preserve system integrity.

Individual SPS should take predetermined, corrective action to avoid a specific phenomenon further aggravating the power system condition by spreading through the system. Each SPS is thus fundamental to preserving system integrity and providing acceptable system performance in the case of a specific phenomenon.

A set of coordinated SPS can then be regarded as a Defence Plan (Figure 4.3)

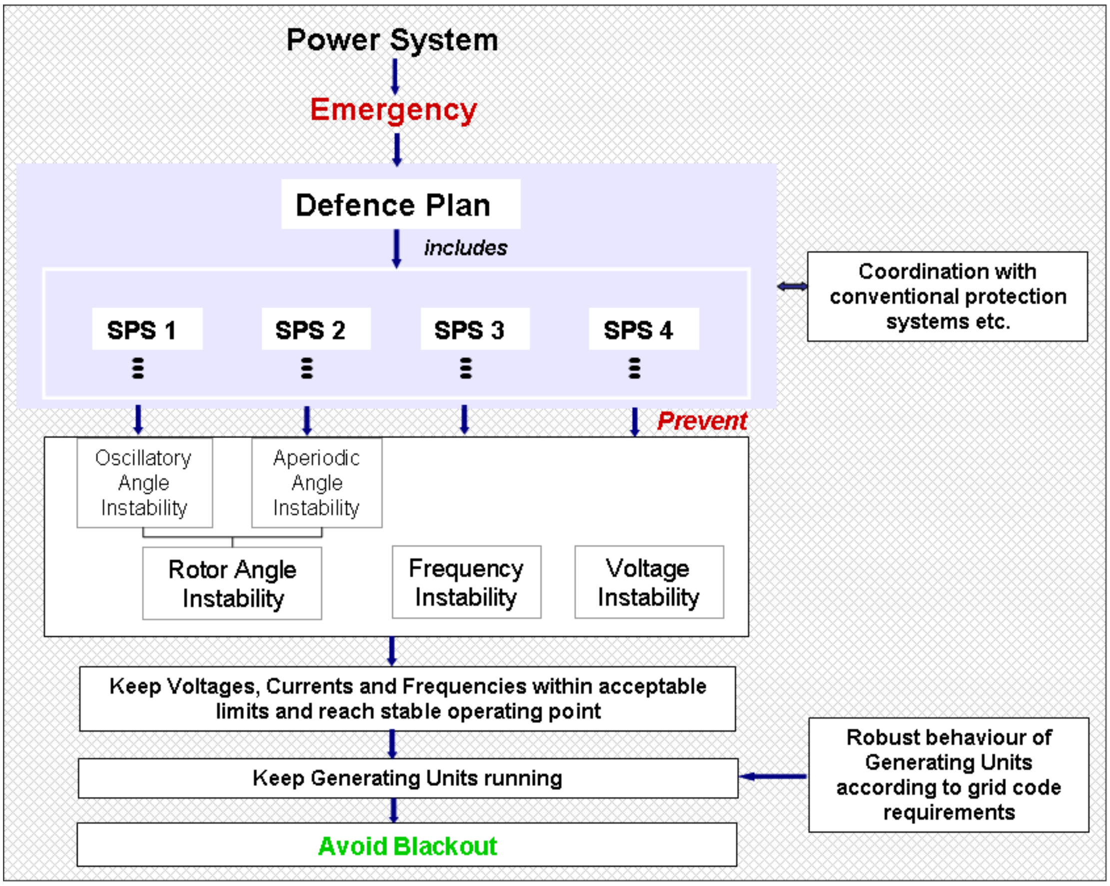

Figure 4.3: A set of coordinated SPS builds the foundation for a holistic defence plan [3]

In densely meshed power systems with dispersed generation and load patterns a disturbance usually passes through all system states before emerging as a blackout (see Figure 4.2). This provides a certain time frame to react before the emergency state is reached and to measure and assess relevant system variables that can be used as inputs for the SPS that are used within the defence plan. These so called *response based* SPS have the advantage that they are efficient also for events that are not explicitly identified, which is important as there are innumerable combinations of possible contingencies that could strike the grid.

If the SPS action is not based on the power system response but on an event itself the SPS is called *event based*. Event based SPS can be used for a limited number of critical events, that are easy to identify and which require quick remedial actions. Especially in weak and highly loaded systems, even single failures in specific scenarios could bring the system from the normal state to an emergency state or even – if no defence plan is implemented – to the blackout state. In such a case remedial actions have to be triggered immediately after the event is detected. Even though the measured system quantities do not yet reveal the loss of stability, in order to trigger appropriate responses, it needs to be known beforehand that the consequences of the event would be critical for system stability and security.

Even with the successful operation of Defence Plans, customer interruptions remain possible but in a generally controlled manner. However, it should also be noted that, due to the complexity of system phenomena, Defence measures responses' cannot guarantee ideal responses to all situations.

The next section briefly summarizes defence measures with respect to different instability phenomena. As the individual measures are described comprehensively in literature, e.g. [1], this Brochure does not go into detail at this point.

4.3.1 Measures to manage voltage instability phenomena

Most of the measures that are implemented by utilities to overcome the risk of voltage instability can be categorized according to the scheme shown in Figure 4.4. It can be seen that sophisticated planning policies and specified operation procedures precede the activation of the actual defence plan.

If operational measures are insufficient to prevent the further degradation of voltage, last resort measures like the blocking of On-Load Tap Changers (OLTC) and Under-Voltage Load Shedding (UVLS) can be initiated to preserve system integrity. The technical concepts behind these schemes (e.g. the methodology to identify critical voltage conditions and thresholds for blocking OLTC and UVLS) can differ between the TSOs.

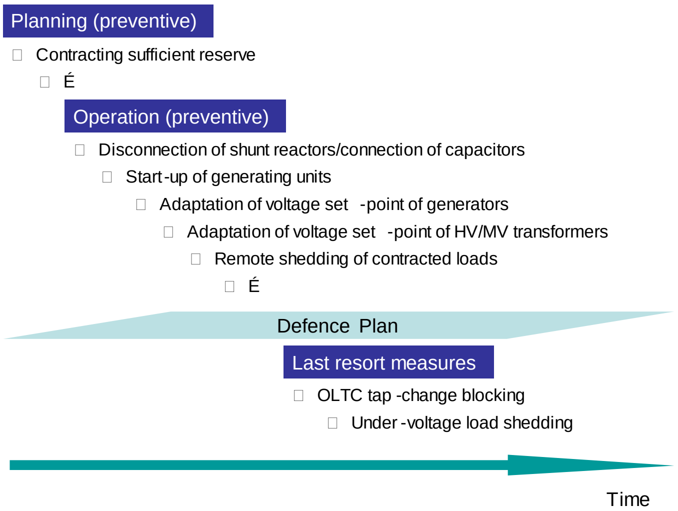

Figure 4.4: Possible measures to overcome the risk of voltage instability phenomena [3]

4.3.2 Measures to manage rotor angle instability phenomena

The phenomenon of rotor angle instability can be subdivided into

- Aperiodic or Non-oscillatory angle instability
- Oscillatory angle instability

and further into small-signal and transient stability sub-categories when focusing on its causes [5][2].

Aperiodic or Non-oscillatory instability results from a lack of sufficient synchronizing torque and could affect both single generating units and entire power system areas. The latter case is referred to as wide area asynchronism, i.e. coherent generating groups slip with respect to each other.

To contain either the transient stability of single generating units or the transient stability of coherent generating groups some utilities have implemented or require fast valving. With appropriate trigger criteria, fast valving could aid the overall system stability by reducing the transmitted power after fault clearance, which is of particular importance when the transmission corridor is weakened after fault clearance.

In order to initiate (controlled) system separation in case of asynchronism some utilities have implemented Out-of-Step Protection on predefined tie lines whereas others rely on the distance protection to separate the system at its natural points, i.e. at the location of electrical centre. Figure 4.5 shows the measures to overcome the risk of rotor angle instability.

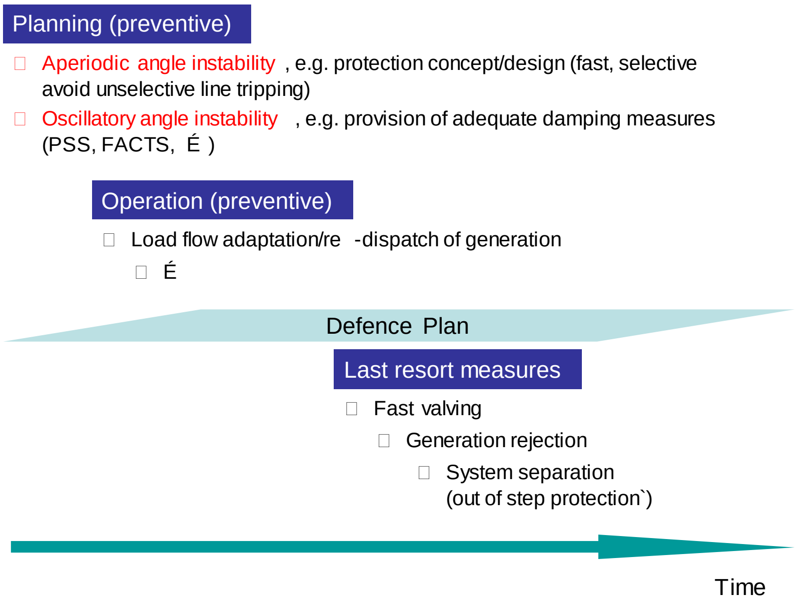

Figure 4.5: Possible Measures to overcome the risk of rotor angle instability phenomena [3]

An important factor in the case of aperiodic angle instability is its evolution with respect to time:

- Fast (pole) slipping is often caused by a heavy transient disturbance (e.g. delayed fault clearing). As classical impedance based Out-of-Step protection does not detect the out-of-step condition until the first pole slip has occurred, a fast voltage fall could occur when the phasors of the concerned areas move towards phase opposition. Depending on the exact voltage profile, generating units that behave in a robust manner according to grid code requirements can resist such a condition if it passes by fast enough.
- A slow (pole) slipping that is associated with a decreasing voltage over several seconds could be the result of a new operating point that is not small signal stable, e.g. a weakened transmission corridor that is not able to transmit the required power. The resulting fluctuations of voltage, currents and frequency could last for a longer time period before out-of-step relays operate. Depending on the exact voltage profile, generating units may be prone to disconnection from the grid and may be more vulnerable to such an outcome than in short-lived transient disturbances.

The analysis of defence plans world wide reveals that the implemented measures against aperiodic angle instability are in the majority of cases tailored solutions for specific power system configurations, e.g. dedicated generating and load centres connected via weak transmission corridors. Under such circumstances it is possible to predefine criteria for system separation by offline studies. In practice, even algorithms for a predictive out–of–step detection are implemented to ensure that the system separation is initiated in due time.

In densely meshed power systems, the risk of loss of synchronism is rather limited and might occur only after multiple contingencies and consequently along paths that are not practically amenable to prediction.

As TSOs are responsible for overall system security, they are in charge of implementing effective countermeasures that suppress the hazardous effects of loss of synchronism and their propagation through the power system. To this end:

a) sophisticated and tailored solutions, e.g. based on research and manifold power system studies, can be implemented for the TSO or a TSO overlapping area (in the latter case agreed between the TSOs that are affected). Such an approach necessitates the identification of endangered network areas and predefined breaking points for system separation, to define actions based on the operation philosophy, requirements on measurements, decisions on the solution structure (e.g. centralised, decentralised) and so on. A good example of a sophisticated defence plan that is based on system studies is the French Defence Plan (see chapter 8 of this Brochure)

b) a straightforward approach is applied <u>in the case that approach (a) is not followed</u>.

<u>Straightforward solution:</u>

- *Conventional Distance Protection:*
  As the loss of synchronism is accompanied by low voltages and high currents in the proximity of the electrical centre, distance protection can serve as “Natural System Protection”, which automatically opens the lines that coincide with the electrical centre. This is a particularly pragmatic approach in cases where the power system configuration makes it difficult to predefine the scenarios and corresponding separation corridors.

- *Out-of-Step Relays:*
  The increasing loading of transmission lines requires optimised performance for the Distance Protection in order to avoid unintended tripping of highly loaded lines, as this might deteriorate a stressed network condition. The distance protection shall be utilised exclusively for “real” electrical faults (short circuits). For this reason, selected zones in case of oscillations are blocked (power swing blocking). In such cases, Out-of-Step Relays/Function have to be implemented/activated

Oscillatory angle instability results from a lack of sufficient damping torque and could affect both single generating units (local oscillations) and entire power system areas (inter-area oscillations). The power system itself (generating units, loads) provides inherent natural damping. The occurrence of undamped oscillation is related to the action of control devices, in particular (fast) automatic voltage regulators, within the power plants. Therefore, countermeasures to manage oscillatory instability are mainly concentrated on prevention by installing additional damping devices (Power System Stabilizer, FACTS,…). In the event of an undamped oscillation, there are similar considerations as for aperiodic angle instability. Depending on the oscillation amplitude, unintended operation of protection devices could result and trip lines or power plants. In the worst case an out-of-step condition could result.

4.3.3 Measures to manage frequency instability phenomena

Frequency instability phenomena have been managed effectively for many years by under-frequency load shedding (UFLS) schemes.

In highly meshed power systems frequency instability phenomena are a matter of concern when it comes to system splitting. Especially when the system is separated along highly loaded transmission corridors the remaining isolated areas suffer a high amount of sudden surplus or a power deficit.

In the latter case it is of utmost importance to stabilize the frequency above the disconnection threshold for generating units (e.g. 47.5 Hz in a 50 Hz System). This is achieved by adequate UFLS.

Even if past incidents revealed a sufficient operation of UFLS, modifications of the UFLS scheme are sometimes considered as necessary. For example, in the UCTE synchronous area this was motivated by [3]

- the principle of solidarity between different TSOs which necessitated an improved harmonisation of UFLS;
- a changing regulatory framework;
- the technical development of load shedding relays (very precise digital relays among which there is not variation of settings within given tolerances are increasingly replacing the old electromechanical relays).

Generally, when implementing UFLS, the following points are of major importance:

- the frequency at which load shedding is allowed to be triggered;
- the frequency at which load shedding is mandatory to start;
- the total load that has to be shed under UFLS, the frequency range in which the total load has to be shed (in any case there must be a safety margin from the lower limit to the threshold for the tripping of generating units) and how quickly the load is shed;
- the number of load steps taking into account the frequency relay characteristic (the steps should be small enough to avoid overshooting);
- the allowed Disconnection Delay;
- requirements on Frequency Measurement;
- whether a decision based on the derivative of frequency is appropriate;
- the prioritisation of different loads, e.g. pumps; and
- the treatment (e.g. compensation) of conventional generating units or renewables that do not behave according to the grid code and disconnect before the allowed threshold.

4.4 Concluding remarks on Defence Measures

Table 4.1 summarizes defence measures that can be used to counteract on different instability phenomena.

It is important to note that at the point when the operation of defence measures is required, the system operator’s main objective shifts from “Minimizing the impact on customers” to “Saving the system”. However, this philosophy generally ensures a benefit for all customers.

As an example, consider a system where 50% of the load is subject to operation of under-frequency load shedding relays. If the system can be saved by load shedding, only some of the customers (maximum 50%) are affected and moreover the disconnection time for these customers would be much shorter in comparison to a total system blackout (Figure 4.6)

Table 4.1 Most used actions to counteract power system instability [4]

Possible measures		Transient instability	Frequency instability: Over-freq	Frequency instability: under-freq	Voltage instability	Cascade line tripping	Small signal stability
Actions on generation	Generation Rejection	*	*		*	*	
	Turbine fast valving	*					
	Gas turbine start-up			*	*	*	
	Actions on the AGC				*	*	
Actions on load	Underfrequency load shedding			*			
	Under voltage load shedding				*		
	Remote load shedding	*				*	
Actions on shunt	Automatic shunt switching	*			*		
	Braking resistor	*					
Actions on equipment	HVDC fast power change	*	*	*	*	*	
	Fast generator voltage setpoint increase				*		
	Controlled opening of interconnection	*		*	*	*	
	Tap changer blocking			*	*		
Closed loop control devices	Excitation controls	*					*
	Power system stabilizers						*
	SVC voltage controls	*					*
	HVDC special controls		*	*			*

A crucial factor for the maintenance of power system stability is that the power system has to be treated as a whole, i.e. including generating units and distribution networks. Nowadays, where utilities are no longer vertically integrated, the TSOs are responsible for overall system security. However, they do not have definitive authority over generating units and distribution networks and so cannot guarantee that they will fulfil their obligations in respect of containment of major unreliability events. As is discussed further in chapters 5 and 6 of this Brochure, it is important to create a legally binding force for the implementation of effective defence plans by TSOs. In this regard the development of technical standards for the different defence measures would be helpful.

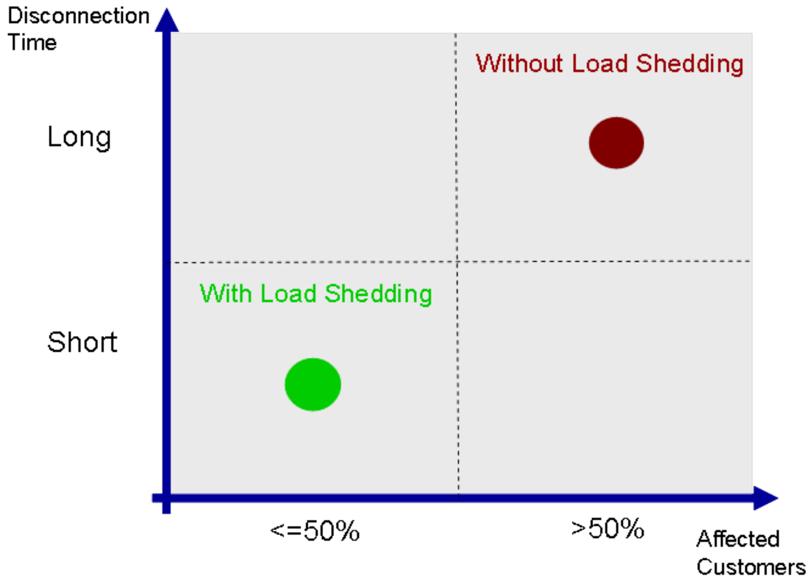

Figure 4.6: The usage of under-frequency load shedding schemes leads to benefits for all customers

In Chapter 2, an overview was given of mechanisms prevalent in major unreliability events. When any kind of instability is imminent and voltages, currents or frequencies breach limits and cannot be restored by conventional control means, Defence measures begin to intervene from the time when a predefined threshold is transgressed. They are designed to bring the quantities back to within acceptable ranges as quickly as possible and in this vein they lay the foundation for generation units to survive the emergency situation.

It stands to reason that the intervention of defence measures could be accompanied by distinct variations of electrical quantities, especially in the transient phase during the transition from one operating point to another.

From this it follows that blackout avoidance requires a certain robustness of all elements operated by all grid users. This is articulated by the need to comply with the respective grid code. Many requirements that are essential for the secure and reliable operation of the entire power system, in particular during disturbed conditions, results as requirements for the individual generation units. For example, in Germany these requirements are manifested in the German Transmission Code 2007 [7].

The power plant/grid interface has to be considered in a holistic way and requires an optimal interaction during critical system conditions. As utilities are no longer vertically integrated a close consultation and transparent information exchange between transmission system operators, generation companies and manufacturers on the technical level is essential and avoids misinterpretations of technical requirements. In any case it has to be ensured that (legally) binding requirements for generation units are set up and that these requirements also reflect the behaviour of generation units during extreme contingencies, whereof all grid users and power plants benefit in the end. For example, for the UCTE area the requirements are given in the technical Paper "Definition of a set of requirements to generating units"[11]. This issue becomes even more important when more and more digital controllers are in operation with numerous possibilities for settings/tunings or activation/deactivation of specific protection mechanisms which complicates the assessment of the behaviour of generation units during extreme contingencies. The need for compliant behaviour of generating units and for the system operator to have accurate information on generators' characteristics is discussed further in Chapter 5.

[11] At time of writing, an ENTSO-E Network Code for Requirements to Generators for Grid Connection and Access is in development in accordance with a direction from the European Commission.

In addition to the impact of generation units on the course of severe incidents, the behaviour of line protection systems, especially during abnormal system conditions (e.g. low voltages, high currents) is critical in the determining whether or not a blackout occurs and its extent. The line protection has different major effects during emergency conditions and stability problems. Previous incidents show that unintended operation of line protection – in spite of correct technical behaviour according to their design and settings – might have both negative and positive effects on the course of the disturbance. During a critical situation unintended and uncontrolled tripping of lines, which are free from electrical failures, might deteriorate the situation due to the resulting weakening of the grid. On the other hand, such unintended line tripping might serve as a system protection, when a stability problem and its propagation through the system is eliminated. Consequently it is increasingly important to ensure high performance of line protection with respect to their original function (fault clearing) and at the same time to implement System Protection Schemes to protect the system against loss of stability.

To sum up, the power grid is a sensitive real time system; a stable frequency and voltage are indispensable for a secure system operation. However, transmission system operators are forced to operate the system closer and closer to its limits with an increasing risk of severe consequences in case of extreme contingencies. Even for single failures this development bears consequences: as long as the thermal N-1 limit is beneath the stability N-1 limit, an online stability assessment is not required for secure operation. However, with the tendency to increase the loading of transmission lines more and more the thermal N-1 limit can be shifted above the stability N-1 limit. In that case, an online stability assessment or dynamic security assessment is necessary for a secure operation (Figure 4.7). In any case, the importance of effective defence measures is rising. However, as already stated, defence measures are no “silver bullet” and should not be relied on as substitutes for substantiated grid planning and design for the provision of essential network capacity.

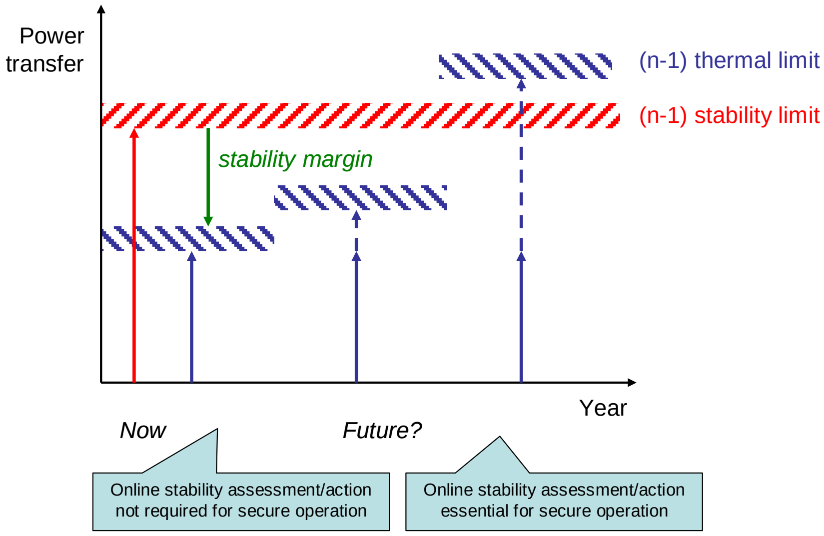

Figure 4.7: Possible future requirements for secure system operation

4.5 Restoration

Despite implementation of various means of action, including safeguard and defence actions, an exceptional combination of unfavourable events may lead to the total collapse of the network of a region, of the whole country, or even beyond the country’s borders.

TSOs must then restore normal System operation with the aim of acting [8]:

- as quickly as possible, in order to limit the impact of the blackout on the country’s social and economic life,

- in a controlled way, while respecting the safety and security of people and property and especially by avoiding any further collapse of the network, particularly fragile during the restoration phase. (A second collapse, like the one that France experienced on 19 December 1978, may lead to the disconnection of areas not affected by the first incident and considerably extend the time required to restore the power supply that had been cut off.)

The following steps are required to be carried out:

- diagnosis of the situation and preparation of the network; and
- network restoration by the main regional structures.

4.5.1 Diagnosis and network preparation

When loss of supply occurs, the grid must be prepared so that the restoration can be carried out under good conditions. In particular, this means:

- avoiding overvoltage problems during the subsequent re-energising of network portions, while making sure not to leave a large unbroken line of power lines or cables;
- preparing controlled load restoration by creating load pockets designed so that they are compatible with the possibilities of restoring load on a single generation unit

Possible overvoltage problems are a particular concern in the early stages of restoration of load. The following preparatory steps were noted by NERC [8]:

- At an investment planning stage, ensure that shunt reactors are available at key locations.
- Remove all transmission capacitors before energizing the bus.
- Check transformer tap changer positions before energizing. During system collapse and voltage decay all tap changers with automatic controls will have run to the maximum or full boost position; these should be lowered.
- Selectively energize known reactive demands to help control voltage.
- Minimize high-voltage problems by energizing interchanges at the same time as the bus is energized.

Among other preparatory steps in the course of network restoration, the following may be noted:

- Open or “green flag” breaker control switches and turn off reclosers. These actions will prevent automatic line-bus condition reclosing of adjacent lines when the bus is energized.
- Energize demands that are on the under frequency load shedding steps to provide some measure of protection if demand exceeds available capacity.
- Identify gas company compressor stations and processing plants that can affect gas supply to generating stations and work towards restoring their service.
- Identify communication facilities that may have no or a questionable back up source of electricity.
- Identify critical oil-filled cables that may be affected by gas pockets in the event of failure of pumps.

In the case of a widespread loss of supply, the national dispatching centre works closely with the regional dispatching centres, to make an as-accurate-as-possible diagnosis of the situation, e.g. where are the dead zones, which zones are still "sound" from the frequency and voltage standpoints, which generation units are operating on house load, how much support is available from neighbouring networks, what is the status of hydro plant reservoirs. On this basis, it defines the general strategy of service resumption: restoration on the basis that the network is still sound or/and restoration via foreign grids, or restoration implemented by the main regional structures.

The pertinence and swiftness of the diagnosis (and, consequently, of service restoration) rely to a great extent on remote information brought back from the field (transmission substations and network user installations) by the telecontrol system, the reliability of which is essential, which in turn determines the overall observeability of the system.

4.5.2 Network restoration on a regional basis

The aim of network restoration is to re-supply priority customers as soon as possible, then gradually all customers, by supplying electrical sources of generating facilities that have tripped so that they can take part in network restoration as soon as possible.

If there is a sufficient core network with a significant amount of generation and number of lines available, service restoration may get under way using that network. Otherwise, or as a supplement (if it serves to speed up service restoration in zones remote from the network in question), TSOs undertake network restoration on a regional basis.

Under the supervision of the regional dispatching centre, each region is re-energised step by step by means of generation units which had tripped to house load and, if necessary, by using pre-established "load pockets". These pockets must be large enough to ensure voltage control under steady and transient operating conditions, while remaining compatible with the load restoration capacity of the generation units connected to the main structure. Care must be taken to manage possible over-voltage situations and to balance generation and demand in each power island.

Once these regional structures have been re-energised, after any partial load restoration (fast restoration of power to priority customers in particular), they are connected with one another or/and with foreign networks on the initiative of the national dispatching centre. The resumption of load then continues depending on the availability provided by the reconnected units and, if need be, on imports set up with foreign TSOs.

4.5.3 Establishment and maintenance of the network restoration plan

Network restoration is based on a succession of complex and delicate operations which should be studied and prepared beforehand.

The various actions to be carried out under such circumstance, along with their sequencing, are described in a “network restoration plan” which lays down the strategy to be followed, the measures to be implemented, the equipment to be installed or configured, the expected performances of this equipment and the respective responsibilities of the various parties involved.

This plan is supplemented by all those concerned (TSOs and users connected to the public transmission system) by the drafting of operating instructions and setting up of the corresponding training actions.

System operators are responsible for ensuring that the network restoration plan is always operational and do so with the other players. This involves monitoring of the performances of equipment taking part in the plan, regular updating of instructions, etc.

Voltage recovery scenarios must be studied, simulated and validated by tests before they are declared operational. Their validity must be checked on a regular basis under operating conditions as must the ability of thermal generating units to trip to house load and restart generators to commence operation under black start conditions. Where such capability is the subject of a contract between the system operator and the generators, proof of the capability via suitable and regular testing should be a condition of the contract. Finally, the TSO organises distributor and consumer surveys periodically to make sure that the load shedding plan is operational.

4.5.4 Non-engineering issues related to network restoration

Other, less technical considerations have been found in many past restoration scenarios to have been critical to the speed and effectiveness of the restoration. These include coordination of human resources and equipment between different utilities and with other authorities such as government, police, ambulance and fire services and with media outlets. In this respect, effective and timely communication is extremely important.

These issues are not addressed further here but discussions may be found in other papers such as [9].

4.6 References

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[8] NERC, *Review of Selected 1996 Electric System Disturbances in North America*, North American Electric Reliability Council, Princeton, August 2002.
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5 Co-ordination with Generation Facilities

5.1 Introduction

This Chapter highlights the importance for management of major unreliability events as well as normal system operation of all aspects of planning, design and operation of generating plant. As was highlighted in chapter 4, continual operation of generation is critical to the power system's ability to proceed through a major disturbance, minimise the load interrupted and shorten restoration time. However, it has seemed to the members of Working Group C1.17 that aspects of coordination between transmission system planning and operation and, in particular, the performance of generation would benefit from renewed attention. Specifically, does generation succeed in riding through faults when required to do so, and why might it not?

With the intention of providing some useful background for transmission engineers who might be involved in specification of generator performance requirements in grid codes, this chapter describes a number of features of generating plant performance in some detail.

5.2 Performance of Various Types of Generation during Major System Disturbances

Understanding the generators' performance during major system disturbances poses a common challenge to system planners, reliability coordinators and transmission and generation operators alike. It relates to defining feasible performance characteristics for new plant but even more so to assessing the ability of the existing plant to ride through abnormal voltage and frequency variations (fluctuations).

Power system planners and operators understand and accept that key system states would depart from their nominal values during a major system disturbance. It is a challenge to define performance requirements sufficiently affordable for generators to be able to achieve them without making unreasonable investments in equipment or system design and without incurring excessive operating and maintenance costs.

5.2.1 Voltage Response

As was discussed in Chapter 4, one of the key objectives when attempting to limit the impact of a system disturbance is to keep key generating plant synchronised without jeopardising the safety or physical integrity of that plant. However, unexpected tripping or runback of generating units coinciding with low system voltages commonly occurs during major disturbances.

The Florida disturbance of February 26, 2008 is one of the more recent examples. Voltage depression, a result of a fault that lasted 1.7s, caused two nuclear units and one gas fired unit to trip, 2500 MW in total. (See, for example, [1]). This was followed by loss of additional generation, 1500 MW in total, precipitating a widespread power interruption to large portions of Florida. Several units were lost when their auxiliary systems tripped on low voltage.

Although utilities understand that voltage dips have widespread impact on power plant auxiliaries supplied directly from AC station service, generally there is a limited account of what really takes place. The following is a record of how an actual voltage dip affected a large thermal power plant in 1996 [2].

> *"The system stayed together for about 2.5 minutes. During this time, the units had major problems due to the initial voltage dip:*
>
> - *Forced draft fan variable frequency drives removed from service and started a boiler runback*

- *Static inverters on the variable frequency drives transferred to battery supply*
- *The submerged slag conveyor removed from service*
- *Soot blower air compressor removed from service*
- *Air preheaters removed from service*
- *Coal feeders ran back momentarily and the furnace safeguard supervisory system (FSSS) put gas in the boiler turbine ran back for about 29 seconds before the boiler was removed from service."*

Criticality of this phenomenon prompted NERC to issue an industry advisory [3]:

> *"In some instances, plant protective device settings on auxiliary or distribution busses caused the generator auxiliary equipment to trip. In others, contactors dropped out at voltages above the station service under voltage relay settings, or before the under voltage relay timers timed out. Some of those auxiliary system trips were related to legacy equipment in older generating stations that may adversely react to voltage sags that do not necessarily impact more modern equipment. All of these situations can cause the generator to trip or runback."*

Protracted low voltages are also known to have had unexpected effects on Combined Cycle generators as described in more detail in subsection 5.2.3.

Planning authorities and regulators typically define a set of pre- and post-contingency voltage conditions that transmission and generation entities are expected to meet. Unlike frequency post-contingency requirements, which appear to be rather uniform among jurisdictions, acceptable post-contingency voltage conditions and expected generator ride-through capabilities vary more widely.

In the development of a voltage ride-though standard, NERC is currently considering the following curve shown in figure 5.1 below. It was derived from the work done by WECC's (Western Electricity Coordinating Council) task force on wind generation [4].

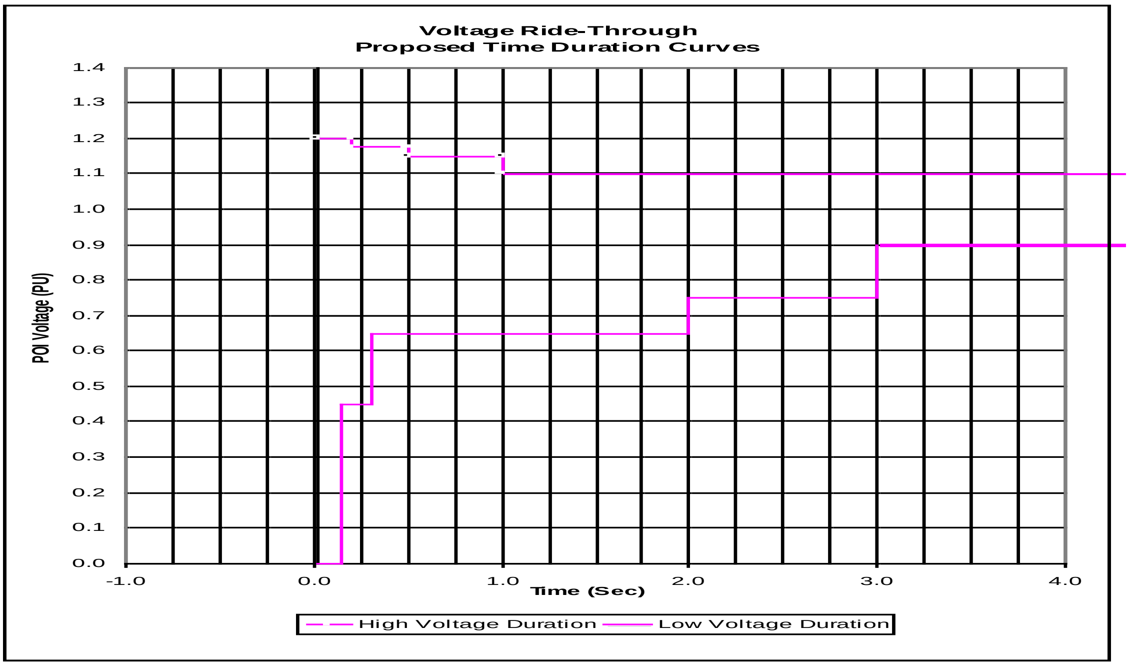


Figure 5.1: voltage ride through requirements under consideration by NERC [4]

In their work, the WECC task force on wind also considered a number of international standards that define fault ride-through for wind generation. (See, for example, [5] and [6] for discussion of international standards) One of German utilities that they used as a reference specifies voltage-time curves depending on the available level of short circuit currents in the network, [7]. For areas with high symmetrical short circuit current the code specifies the curve shown in figure 5.2.

For portions of the system with low symmetrical short circuit current, typically with a large content of wind generation, the curve shown in figure 5.3 applies.

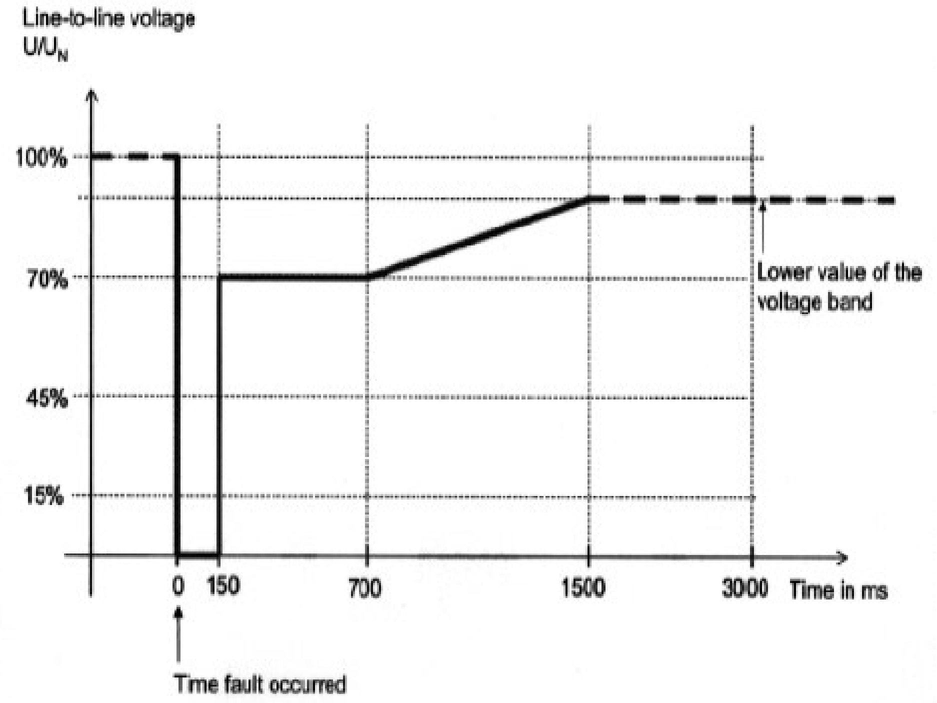


Figure 5.2: low voltage ride through specified by E.On Netz [7]

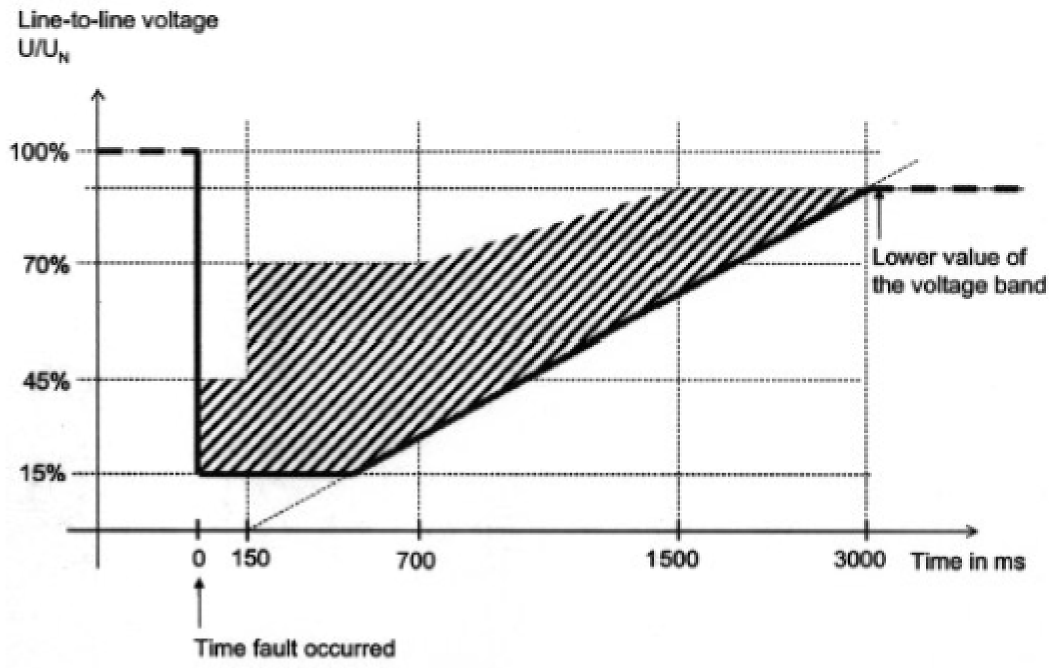


Figure 5.3: E.On Netz low voltage ride through at locations with low short circuit levels [7]

5.2.2 Frequency Response

Frequency Response or the Frequency Response Characteristic (FRC) is a natural reaction of generators and loads to frequency variations resulting from load-generation unbalance in a system.

The frequency deviation in a large interconnected system may be described by

$$\Delta f = -\Delta P\left(1 - e^{-1/T}\right)K$$

where ΔP is the power deficit, $K = 1/D$, D is the load-damping constant in the power deficit-area, $T = M/D$ and M is the inertia constant of the generating units.

The chart in figure 5.4 shows a typical pattern of system frequency following a loss of a large generating source. Characteristic points A, B, C, and D are annotated.

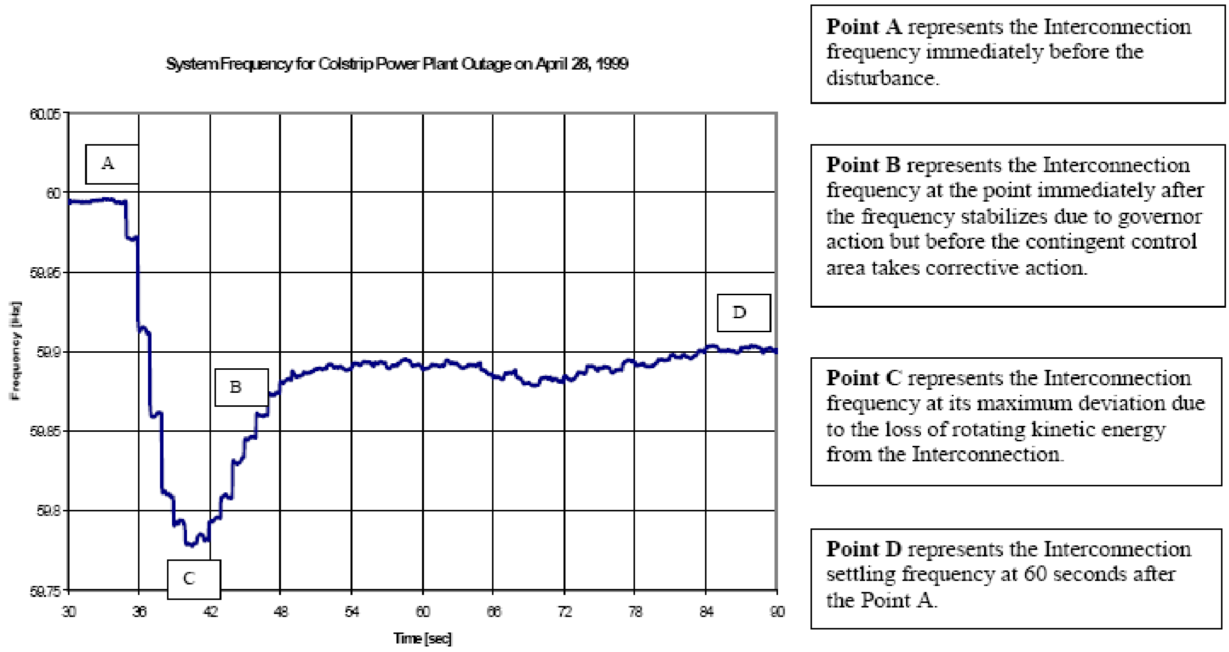


Figure 5.4: Typical system frequency response following loss of a large generating unit [8]

Frequency response of generating plant has become an issue of increased importance. In figure 5.4, frequency recovery resulting from generator governor action is shown on the portion of the curve between points C and B. Eastern and Western interconnections of North American bulk electric system have experienced a trend of decline in the overall system frequency response despite an increase in generation capacity and load. This phenomenon produces a settling frequency (point D) that is getting lower than it used to be in the past. Such trends have prompted heightened scrutiny in North America of generator response and governor controls characteristics. In Europe, the low inertia of wind generation has highlighted similar concerns.

The following review of the characteristics of various types of generating facilities focuses primarily on their ability to sustain and control frequency and voltage deviations.

5.2.3 Natural Gas Plants

Natural gas fired generating stations with simple combustion turbines (CT) or Combined Cycle plants (CC) became widespread in 1990s. Consequently, analysis of their performance during system disturbances has become increasingly important.

Gas turbines within a Combined Cycle (CC) plant normally operate at their base load output limited by turbine inlet and exhaust temperatures. Gas turbine MW output is affected significantly by ambient temperature that may limit the maximum fuel valve opening. Another characteristic of the gas turbines operated at the normal base load is that their power output is directly proportional to the square of system frequency. Hence, decreasing frequency reduces the power output of a turbine.

CC plant steam turbines will normally operate in a sliding pressure mode unless equipped with a supplementary firing system. Change in their output lags behind the change in gas turbine output, delayed by the time constant of the heat recovery stage which is typically in the order of 2 min.

The performance of CC and CT plants has been the subject of few recent NERC alerts. One of the alerts warns about "turbine combustor lean blow-out" during sharp frequency rise as described in the excerpt below [9]

> *During the protracted fault, voltage locally went to near-zero, which effectively reduced the area load and thereby caused area generators to accelerate. Indications are that six combustion turbine (CT) generators within the Region that were operating in a lean-burn mode (used for reducing emissions) tripped offline as result of a phenomenon known as* ***"turbine combustor lean blowout."***
>
> *As the CT generators accelerated in response to the frequency excursion, the direct-coupled turbine compressors forced more air into their associated combustion chambers at the same time as the governor speed control function reduced fuel input in response to the increase in speed. This resulted in what is known as a CT "blowout," or loss of flame, causing the units to trip offline.*
>
> *This phenomenon is not well understood throughout the industry as it may be dependent on various frequency parameters that include frequency magnitude, rates of change, and the source of the frequency excursion.*

Another major disturbance perpetuated by the loss of CC plants occurred in the Malaysian power system on 3rd August 1996, ref [10]. At that time, two thirds of power in Malaysian electric power system came from combined cycle power stations. The issues were in a way similar to those described in NERC's alert. During the disturbance, the system frequency dropped to 49.1 Hz within 3 sec. This caused further loss of over 2000 MW of mostly CC generation. Subsequent investigation found two phenomena to be responsible. One is related to excessive turbine temperatures as units were attempting to increase their power output. The other was flame-out due to the inability of turbine controls to cope with reduced air flow as axial GT compressors were running at reduced speed.

Natural gas generating stations are also notorious for susceptibility to single points of failure that result in contingencies exceeding normally expected first contingencies and affecting a large pool of generators. Of particular concern are gas supply issues caused by failures of gas pipelines or shortages in times of high gas usage.

Certain disturbances indicate that even a gas distribution of a single plant can produce problems. In 2002, Collins power station located in Chicago area lost four out of five 500 MW generators due to a gas line pressure dip that occurred during an emergency repair of a gas line component. This dip resulted in flame instability that only one unit managed to ride through. Operators attempted to stabilize firing by manual generation run-back of 300 MW. This attempt was not successful and within a minute over 2000 MW of generation was lost, significantly exceeding the worst single contingency considered in system planning for that area[12].

Some utilities, for example National Grid in Britain, include special provisions in their codes to recognize the specifics of gas turbines whose power output may decline under prolonged under-frequency conditions [11]. Similar to many other utilities, National Grid requires all generating units

[12] In Britain, for example, some concern has been expressed about the impact on the electric power system of loss of gas supplies to combined cycle gas turbine power stations. However, to WGC1.17's knowledge, no significant study of this has been published although it may also be noted that, in Britain, the largest CCGT station is smaller than the biggest loss of infeed risk that is normally secured against. Furthermore, in respect of the UK's gas supplies, the probability of failure of a pipeline near to a power station is seen as low and disruptions to gas import capability actually give some hours' notice of potential shortages of gas at power stations which gives an opportunity for replacement generation to be scheduled, assuming sufficient capacity is available. The key questions that perhaps then arise are what proportion of total generation capacity is dependent on gas and what proportion of the gas supply might be vulnerable to single disturbances.

to maintain full power output within +/- 1% of nominal frequency. Generators are also required to stay on line up to 5 min. Nevertheless, the code accepts that certain reduction in gas turbine power output may be necessary in order to keep the generator on line.

5.2.4 Fossil Plants

Thermal power plants' ability to remain on line during a system disturbance depends largely on process controls that allow riding through frequency transients. Advanced thermal unit controls coordinate boiler and turbine control loops so that all process parameters remain within acceptable limits.

The block diagram of thermal unit controls in figure 5.5 is provided for information only. It illustrates in generic terms complexities of evaluating fossil generating station performance during frequency disturbances.

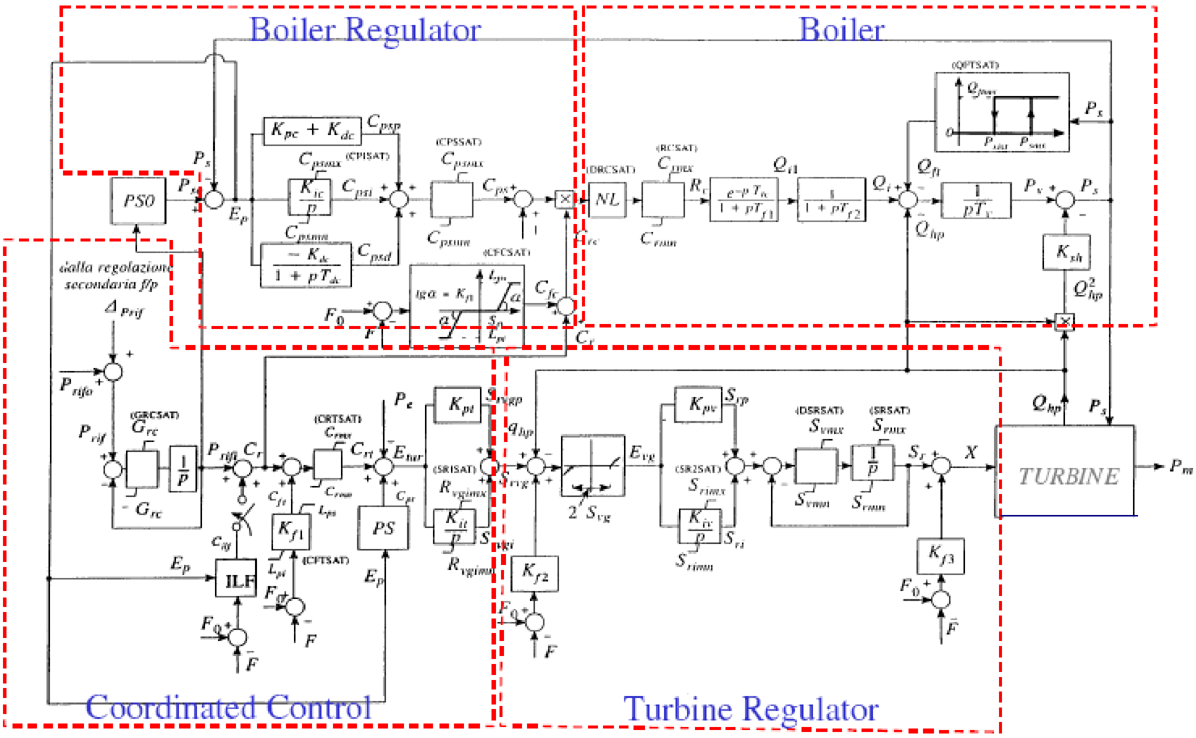


Figure 5.5: Block diagram for frequency control and supply system of thermal unit with oleodynamic turbine regulator [12]

Sudden loss of significant load centres or creation of over-generated islands makes fast generation run-back a necessity and poses significant challenges. Firstly, flow of fuel to the boilers has to be reduced immediately, accompanied with adequate control of other process parameters.

For once-through boilers, feed-water flow is promptly reduced. For drum type boilers, control of feed-water flow is coordinated with controlling drum level within acceptable limits. Regardless of boiler type, air flow to burners has to match reduction of fuel flow to maintain a stable flame.

Common techniques to achieve significant reduction of a steam turbine power output in a short period of time are fast valving and steam by-pass schemes. The following excerpt describes one typical approach [13]

"Steam turbines are discharged through a control system using two inputs: a fast acting electrohydraulic converter and a slow acting turbine control mechanism. The unloading of turbines can be short-term, or impulse, through partial shutting of the control valves for several seconds, only for the duration of the transient state, with a subsequent restoration to

the initial production level. It can also be long-term, with the reduction of the boiler output, when the network is weakened, for the duration of the post-fault operating conditions, constraining the power flow based on static stability. The power of the turbines can be reduced to several levels."

This feature is indispensable for the ability of thermal power plants to remain in service during frequency transients.

5.2.5 Nuclear Plants

Understanding and simulation of rectors' behaviour during power system disturbances is a challenge that system planners and utilities face during plants' design stage, when developing System Protection Schemes, system restoration plans, or when analyzing complex power system incidents.

Initial response of nuclear turbine controls to frequency variations is similar to the response of any other generating unit controls. In case of a partial load rejection, turbine inlet valves are closed and turbine by-pass valves opened. However, the effect on the nuclear process systems depends on the reactor design.

For example, a general characteristic of pressurised water reactors (PWR) is that reactor power output follows turbine output. In response to an increase in frequency, governor control reduces steam flow in the secondary loop, which in turn increases reactor temperature. Higher reactor temperature slows down fission and results in decrease of reactor power, a phenomenon known as a negative feedback. Adjusting reactor temperature and power output during short-term load transients is achieved by control rods that absorb neutrons as needed to maintain desired level of fission.

The boiling water reactor (BWR) is characterized by relatively low pressure water coolant flowing directly through the reactor core so that steam is created in the process. Control of reactor power is achieved by adjusting the coolant (water) flow rate. Therefore, when a turbine governor reduces steam flow in response to a frequency increase, the pressure of steam exiting the reactor increases. Water and steam are the reactor's coolant and moderator. This increase in pressure results in a reduced portion of steam in water, which leads to increased slowdown of neutrons (moderation), which in turn intensifies fission in the reactor. This positive feedback to an increase in frequency is opposite to what happens with PWR designs and is not desirable. Increased system frequency also may speed up recirculation pumps, increasing the flow of coolant (water) through the reactor. Since this precipitates removal of steam bubbles the coolant is moderating even more neutrons, increasing power produced by a reactor. Given that a BWR depends on an equilibrium between water and steam and is sensitive to pressure changes [14], it is more difficult for BWR units to handle system frequency transients compared to PWR units.

Regardless of a reactor technology, nuclear stations are equipped with extensive safety shutdown systems and emergency off-site power supply facilities.

If a power system disturbance is such that full generation runback is needed, usually it is necessary to insert control rods to induce shutdown quasi-instantaneously and then borate the primary circuit sufficiently to enable the control rods to be fully withdrawn. Large, rapid reductions in power lead to a significant build up of Xenon, which is a strong absorber of neutrons, over a period of 9 hours following power reduction and this can delay the return to full power of the reactor. Accordingly, other measures, such as venting steam to atmosphere so as to drop to a power level sufficient to meet 'house load' for ancillary plant can be employed but as the very loud 'whistle' produced in so doing can worry the local population, the operator may not wish to do this.

5.2.6 Hydroelectric Plants

Hydroelectric generation is quite flexible and can operate under large frequency deviations provided that the voltage at generator terminals remains within limits (during transients typically within +/-

15% of nominal value). They are well suited to support of islands or provision of black-start capability. The key is to have hydro units equipped with effective governor and excitation systems.

Due to their construction characterized by salient pole rotors, hydroelectric generators can support a wide range of the transmission system's reactive power needs. Unlike generating units with round rotors, hydro generators are not limited by rotor end heating when operating in leading power factor mode. To allow maximum use of such capability, it is necessary to have effective and properly coordinated excitation and protection systems. (This aspect, common to all types of generation facilities, will be elaborated further in section 5.3).

While hydro generation offers robust frequency ride through capability, it is not good at quickly responding to frequency changes. This generally results in larger frequency deviations in systems that have predominantly hydro generators and no synchronous connection to other systems (e.g. Tasmania and South Island of New Zealand). The wider frequency variations in these systems pose difficulties in connecting plants that have poor frequency ride through capability e.g. CCGTs

5.2.7 Wind Generation

Assessing the performance of wind generation is a particularly difficult task when planning to mitigate impact of major unreliability events, not only because of the somewhat random nature of wind patterns but also because of the variety of generation technologies in use. That wind generation can have a major impact has been evident from the European blackout in 2006 and disturbances in ERCOT (Texas interconnection).

Reference [4] provides a detailed account of performance requirements and modelling issues related to various wind generation technologies.

In 2009, the two most prevalent types of designs are units with asynchronous (squirrel cage) induction machines and doubly fed induction machines with converters. Increasing numbers of units are also now being installed using synchronous machines connected to the system behind fully rated converters.

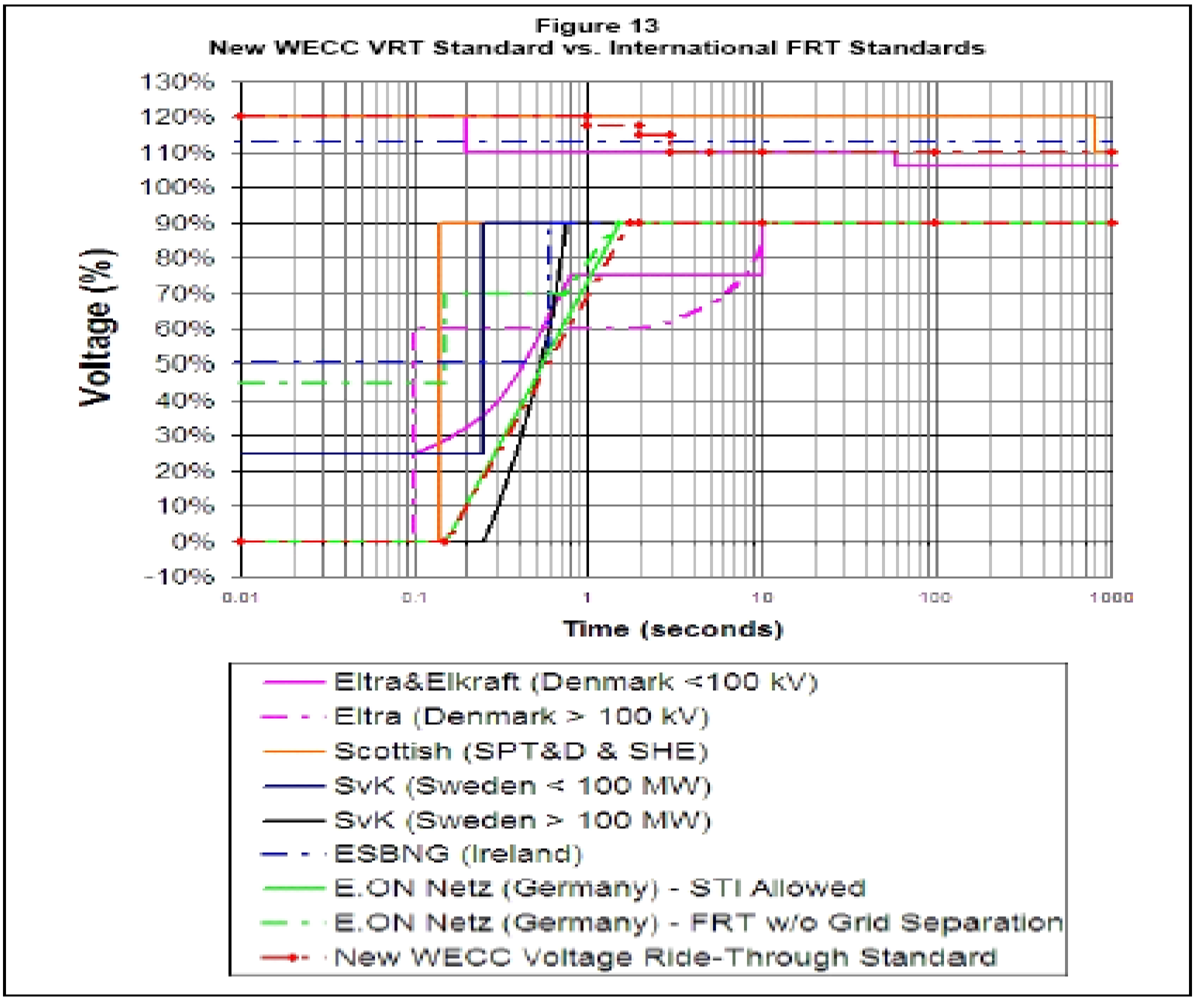
Across the world, a majority of the existing wind generation cannot successfully ride through relatively modest voltage drops caused by network faults. Under-voltage protection of asynchronous wind generators is typically set around 85% of nominal and delayed long enough (up to 300 ms) to allow system protection to clear the fault. Early designs of doubly fed induction generators (DFIGs) cannot sustain voltage dips below 90% of nominal and usually trip even for remote system faults.

At the time when initial connection requirements were put in place, wind generation was scarce so their impact was not a major concern for system planners. Today large concentrations of wind farms, often remote from major load centres, can play a significant role during system disturbances.

Recently, grid connection requirements started calling for new wind generation designs that are able to feed reactive power and remain on line during fault conditions (see, for example, [6] and figure 5.6 below). Even older installations are being considered for retrofit in order to gain such capability. Three key requirements are:

- wind farms should not excite system oscillations after grid disturbances;
- voltage support to be provided during and after the fault; and
- maintaining frequency and participating in system frequency regulation by reducing generation when possible.

New controls based on power electronics should enable wind generators to ride through dips down to 20% of nominal voltage for up to 500 ms. Wind manufacturers have started introducing "crowbars" to control the converter voltage of DFIGs which would allow them to sustain low system voltages without tripping.



FRT – Fault ride-through; STI – Short term interruption

Figure 5.6: comparison of low voltage ride-through requirements [4]

5.3 Improving the Resilience of Generating Stations

When a portion of a system gets to the brink of a collapse, the only possibility to preserve it is to have generators that will sustain the system long enough to allow it to find its new equilibrium. To achieve this goal, the design of generator controls and protection has to allow robust unit response that at the same time would not endanger the equipment. As there are no hard-and-fast rules on this subject, the approach depends on engineering expertise and judgement, equipment owners' risk tolerance and economic incentives to allow equipment to stay on-line under emergency conditions.

Temporary operation at emergency levels may be feasible in some cases. Such operation may entail added costs due to loss of efficiency or may result in potential loss of life expectancy of the equipment. If planners do need such capability, the requirements and compensation are normally set through ancillary services contracts.

Post-disturbance review of generating stations' performance, especially investigation of the behaviour of those units that tripped prematurely, is indispensable in discovering and mitigating shortcomings in the design or application of generator controls or protections. This in return improves the resilience of generating stations when exposed to system disturbances.

An example of a recommendation derived from a disturbance analysis [15]

> *Test and calibrate for proper operation the generating unit turbine-generator speed and load control devices and all exciter-motor over-speed switches. Repair the main governor pilot valve on Unit 5. Test the coordination of the loss-of-field relays with each generating unit's Under-excited Reactive Ampere Limit (URAL) and replace the loss-of-field relay on Unit 2 that was determined to be defective. Provide control system modifications, which were identified during the investigation that would further enhance the units' ability to respond to island conditions.*

The remainder of this section addresses various issues associated with generator control that can affect system resilience. While not exhaustive, some of the examples given might help to emphasise the need for rigour in testing and coordination of systems.

5.3.1 Coordination of Generator Protection and Excitation System Controls

Through experience of major unreliability events, the electric power industry has recognized that coordination of excitation and protection systems is one of the key preconditions for achieving robust generator performance during a disturbance while assuring that equipment operates safely within its design limits.

The Blackout of August 14th 2003 that affected North Eastern USA and province of Ontario in Canada earned notoriety as the largest power system collapse in history. It brought again into focus the need for better coordination of generator excitation and protection systems.

Events surrounding the Blackout have been thoroughly analyzed and findings presented in a number of documents. One of them, the NPCC Blackout report [16] indicates that large units which tripped prior to the formation of islands, perpetuated the break-up of the NPCC system.

> "During the events of August 14, most of the generation trips within NPCC occurred after formation of the islands (i.e. after second separation of Ontario and New York at around 16:11:10). However, because simulations indicate that the system was very close to maintaining synchronism, each generation trip that occurred prior to island formation contributed to the power swing that eventually resulted in separation of NPCC into four islands."

Some of the major generating units in Ontario were among those that tripped prior to the formation of the islands. Their performance was subject to further investigation. The investigation revealed certain commonality in the response of the affected units that experienced severe over-voltages coincident with abrupt increases in system frequency during the disturbance. Figure 5.7 provides a snapshot of system frequency during final moments of the August 2003 power system collapse in Ontario and should help to understand the phenomenon.

Ontario Electricity Market Rules require that the majority of generating units above 10 MVA must have static exciters and power system stabilisers (PSSs). In some cases, pilot exciters on large units are also equipped with PSSs. All PSSs in Ontario are based on a $\Delta P\omega$ concept, with dual inputs as represented by IEEE model PSS2 in figure 5.8 below. The PSSs respond to variations in units' electric power and frequency (speed) as long as the changes fall within the operating range set by signal filters.

During the Aug 14th 2003 disturbance, the PSSs responded to the fast frequency transients depicted in figure 5.7 above by boosting or bucking excitation as expected by their design. Prolonged frequency rise that followed the second stage of load shedding caused PSSs to boost excitation.

The problem with the two units that tripped at the peak of the rise was that excitation limiters could not restrain boosting. This produced severe overvoltages on the units' terminals that lasted long enough to activate several protections. It is interesting to note that even A and B differential protections on one of the step-up transformers tripped due to inrush current caused by the transformer overexcitation.

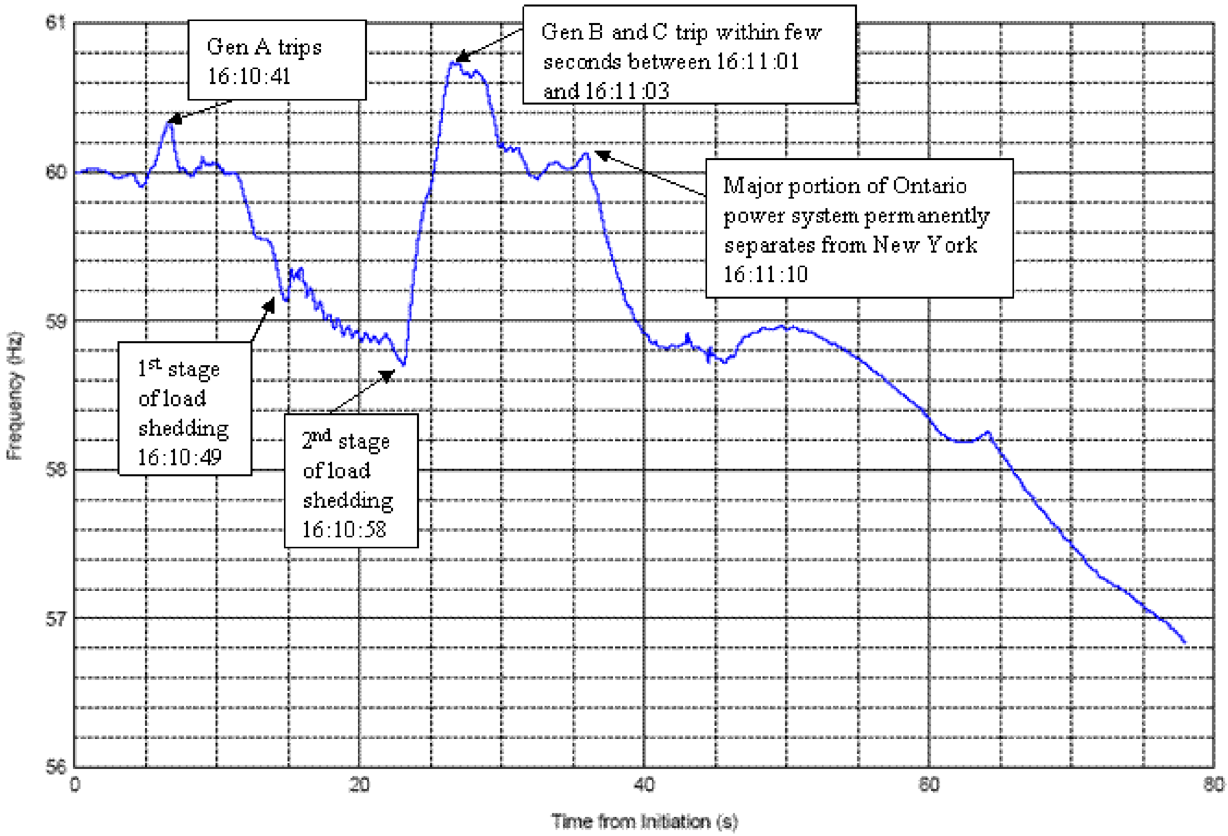


Figure 5.7 System frequency in August 2003 North American collapse [16]

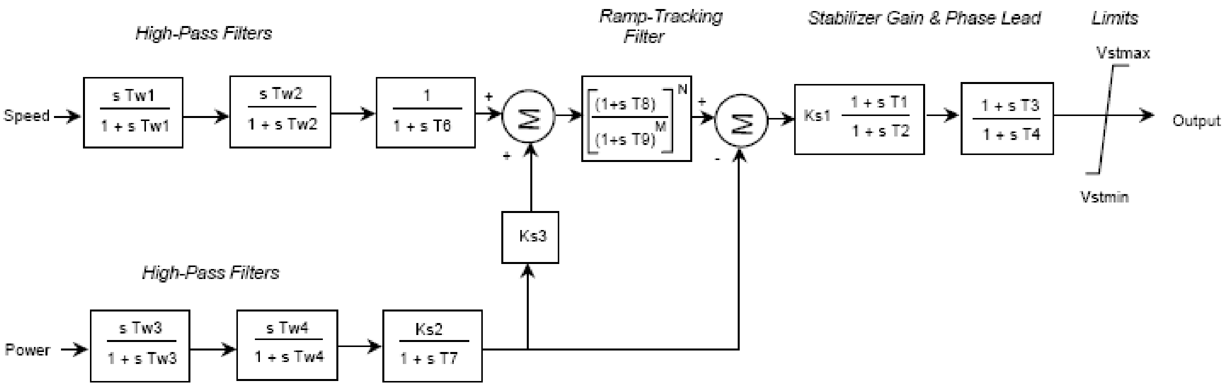


Figure 5.8: block diagram of IEEE PSS2

Subsequent engineering work in Canada has produced a set of measures internal to Ontario Power Generation for standardising and improving the design and application of particular digital excitation systems :

- reconfigure controls to allow excitation limiters to restrain PSS signal effectively;
- upgrade limiter functions to improve the response and setting flexibility;
- upgrade the existing AVR channel transfer schemes to assure dependable performance; and
- enhance PSS failure detection.

Major disturbances inevitably produce significant frequency transients, especially pronounced following the shedding of load. Their effect on the response of PSSs and associated excitation systems needs to be studied carefully in order to avoid application pitfalls.

The importance of effective excitation limiters has commonly been noted in the aftermath of major disturbances. For example, in March 1996 the Brazilian system experienced a disturbance creating a large island where frequency decreased while system voltage increased due to load shedding. Several major units were lost when step-up transformers were tripped by V/Hz protection. Interestingly, it was observed that generating units equipped with V/Hz limiters withstood larger frequency deviations compared with those without such devices and were the last ones to trip before the island collapsed.

The following incident, although of smaller scale, illustrates another aspect of excitation control systems' impact on unit performance during power system disturbances.

In April 2003, a 765 kV circuit breaker failure at AEP's Rockport transmission station tripped a number of station elements. This left two 1300 MVA Rockport generating units connected to the system through the only remaining 765 kV line. Within several seconds, the units experienced un-damped oscillations and tripped. The frequency record is shown in figure 5.9 below.

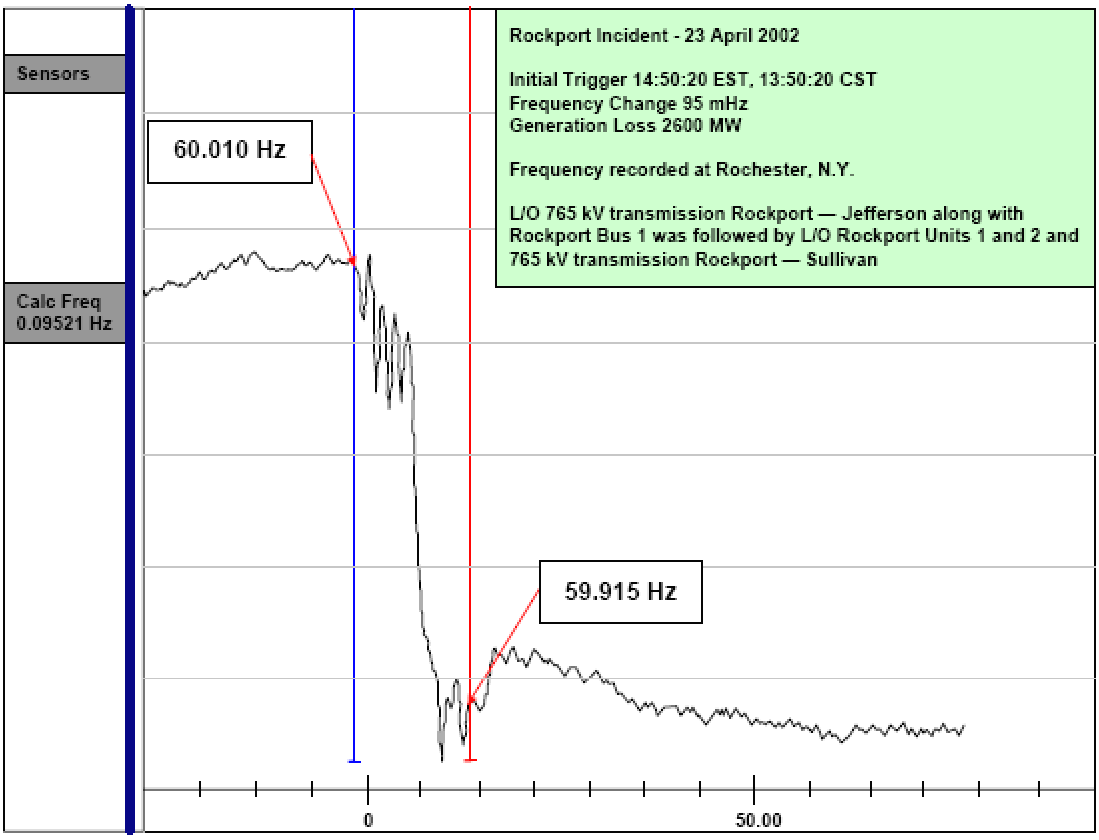


Figure 2 – Rockport Frequency Plot

Figure 5.9: plot of system frequency during Rockport incident [17]

Subsequent investigation determined that AVR gain was set too high. (While it is not clear from the report, it can be inferred that the units did not have PSSs).

When AEP placed the second Rockport unit in service in 1989−90, extensive excitation system testing was performed. This testing revealed a need to re-tune the excitation system equipment as documented in [18]. However, in April 2000 and April 2001 the voltage regulators of both units were replaced with new equipment but the level of testing and analysis was not as high as following the initial installation.

The 2003 Rockport incident underlines that high AVR gain applied on high response excitation systems improves synchronizing torque but diminishes damping torque of a machine. This may manifest itself through un-damped oscillations during contingencies that weaken the system. In addition, it highlighted the importance of accurate modelling of excitation system equipment in system dynamics studies. This is particularly critical for stability-limited units such as those at Rockport generating station. Models should be verified by appropriate testing or online performance monitoring of excitation system equipment.

5.3.2 AC and DC Station Service, Plant Process Systems

Nuclear, fossil and gas turbine generators are particularly sensitive to malfunctioning of AC/DC station service supplies and plant auxiliary systems. The impact is hard to predict and may be well beyond worst case contingencies accounted for in planning and operations studies. For planners and to some extent for asset owners, this area tends to be a “black box”

The following is a list of real life problems that have occurred during various disturbances. Some of these examples are taken from the NERC’s site on event analysis [19] while others come from Ontario Power Generation’s (OPG’s) experience:

> “Due to the failure of an automatic transfer scheme, auxiliary power supply to a circulating water pump was lost. The pump went into reverse rotation. As a result, circulating water flows to the plant were reduced, ultimately causing activation of a low turbine vacuum protection. Electrical system 4,160 V bus transfer scheme and procedures were reviewed and formalized.
>
> A study of the circulating water system was done resulting in modified valving on the circulating water system. The valving can now be closed faster to prevent the same situation from occurring in future. This emphasises the need for careful consideration of interactions between common systems in a thermal power plant.”
>
> “While performing power supply switching on the 4 kV station service system, interruptions occurred to multiple station compressors. This forced out of service four large thermal units due to inadequate compressed air supply. Remaining compressors were unable to supply station compressed air demands and subsequently failed. Lost generation 1879 MW.”

The following is a first-hand account of the possible detriments of a prolonged loss of AC and/or DC station service supply that staff of one of OPG’s fossil generating stations prepared after the Aug 2003 Blackout:

> “If the station service loss occurred in the winter, the auxiliary boiler for building heating would not be able to operate resulting in the potential freeze up of the unit after approximately four hours. Temporary heat supplies such as propane cylinders and burners would be in high demand throughout the region given the cold temperatures.
>
> Loss of jacking oil pumps would result in turbine shafts ‘hogging’ because with no jacking oil, the turning gear will not operate and it is impossible to manually rotate the turbine without jacking oil. This would significantly increase return to service, as well as potentially jeopardize asset condition. DC lube oil and seal oil pump power supply would be in jeopardy after 4 hours due to battery power exhaustion.”

Other issues that can endanger the assets or cause extensive generating station outages, especially if a prolonged power interruption happens during winter months include:

- freezing of head gates or sluice gates at hydraulic stations;
- damage to transformers with water cooling systems; and
- loss of air pressure in HV air blast breakers that automatically trips and locks them open.

Investigation of the February 18, 2006 disturbance that affected the Public Service Company of Colorado identified that the loss of a steam generating unit on a combined cycle plant could result in loss of the associated gas turbine units. A similar problem was exhibited during the September 18, 2007 MRO disturbance, where all gas turbines in a combined cycle plant were lost following the tripping of the heat recovery steam unit.

Coordinated Boiler Controls mentioned in section 5.2.4 is an important design solution that allows a unit to cope with malfunctioning of certain components or control loops of process systems.

5.3.3 Turbine Controls

Characteristics of Nuclear, Fossil and Gas Turbine generation facilities, including some of the features of their turbine controls, have been described in section 5.2. This section provides additional examples and details of problems experienced by turbine controls during system disturbances.

Even a smaller scale disturbance, such as the one that occurred in Ontario in 2005, may reveal peculiar design issues with turbine controls. An error while energizing a major 500 kV switchyard following maintenance resulted in a loss of approximately 2300 MW of load accompanied with a sharp increase of system frequency. Several generating units ran back or tripped. Subsequent analysis determined that one of combined cycle co-generating units tripped due to the increase in the angular velocity of the low speed shaft that activated "shaft shear" protection, an element of the gas turbine protection scheme. The manufacturer was requested to investigate if the protection logic needed to be so sensitive.

Another incident that took place in Ontario back in 1972 revealed an issue with the design of mechanical hydraulic governors of Pickering nuclear units. A series of contingencies led to the formation of an island. Initially, surplus of generation in the island caused its frequency to increase to 62.5 Hz, followed by a drop to 59 Hz due to action of turbine governors. This activated the first step of underfrequency load shedding followed by frequency swings between 62.6 Hz and 58.7 Hz. The island eventually stabilized at 60.8 Hz.

Post-disturbance investigation pointed to the "auxiliary governors" associated with the main mechanical-hydraulic governors that were provided to limit overspeed during full load rejection. The auxiliary governors were set such that a significant overgeneration would cause a rapid closure of the steam valves. The resulting reduction in mechanical power decreases the speed so the steam valves reopen. This again increases the mechanical power and the cycle repeats, causing frequency instability. Frequency oscillations affected generator turbine governors throughout the system. Due to the excessive repetitive movement of wicket gates of hydraulic units or steam valves of thermal units, their governors run out of fluid causing unit tripping.

The problem with the governors at Pickering was eventually solved by replacing auxiliary governors with electronic acceleration detectors.

The incident at AEP's 765 kV Rockport transmission station was described in section 5.3.1. In addition to Rockport generators, a large generating unit (600 MVA) at another generating station was removed from service by power-load unbalance control system element that was set to be too sensitive. The scheme did not have time delay that would allow a unit to ride through an unbalanced condition that was not sustained.

5.4 References

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6 System Coordination

6.1 Introduction

As can be seen from the review of incidents in chapter 2, a number of major disturbances have been provoked or amplified by a combination of factors related to protection and control systems. These factors fall into several categories including design deficiencies, installation flaws, equipment malfunction and human errors during maintenance and testing. The detailed performance of protection and control is sometimes beyond a power system planner's normal priorities and wider system behaviour outside those of protection and control engineers. In view of the role of protection and control in major unreliability events, it may be argued that behaviour of these facilities under somewhat abnormal system conditions is worthy of particular attention and a section below is dedicated to it. Recognising a planner's role in providing adequate facilities to operators and the difficulty of changing systems once they are in operation, these aspects of coordination should perhaps be highlighted especially for planners who have an opportunity to ensure adequate performance in advance of both local facilities and the system as a whole in advance of connection of new generation.

Other aspects of coordination are also briefly addressed in this chapter. These include

- the importance of monitoring and data recording for post-event analysis;
- compliance testing of generators and enforcement of rules;
- the coordination of standards; and
- the coordination of different defence measures.

Another subject concerning coordination is that between different system operators responsible for different areas of an interconnected system. The need for that has been highlighted in a number of reports of major system incidents, e.g. [1][2], and is not discussed further here.

6.2 Protection Design Philosophy

Design of secure and dependable protection and control systems has always been an important element of power system reliability achieved through coordinated and interactive effort of protection and system planning engineers.

Protection system failures often lead to more severe power system disturbances due to prolonged fault clearing times and/or unnecessary loss of multiple power system elements.

Protection specialists have hitherto conventionally striven for dependability of the schemes (certainty that protection will operate correctly when required) at the expense of security (certainty that protection will not operate incorrectly).

This subject has recently drawn renewed attention of protection experts, asset managers and regulatory bodies.

Reference [3] presents the results of a survey on incorrect operation of protection systems carried out for several years in Netherlands. The findings are summarised in figure 6.1.

The Dutch survey confirmed what many professionals in this field have learned through experience or have known intuitively: more of the problems with protection systems are a result of human errors than of equipment malfunctioning.

The design philosophy presented in [3] revolves around simplification of schemes, reducing the number of elements and minimizing a need for human interaction and interference during the lifecycle of the systems.

There is not necessarily a consensus on the benefits of redundant designs. North American utilities have been interested in a guideline for determining a proper level of redundancy that will ensure reliable protection system performance taking into consideration the actual impact of protection maloperation on bulk power system behaviour. The guideline has been developed by NERC's System Protection and Control Task Force (SPCTF) [4].

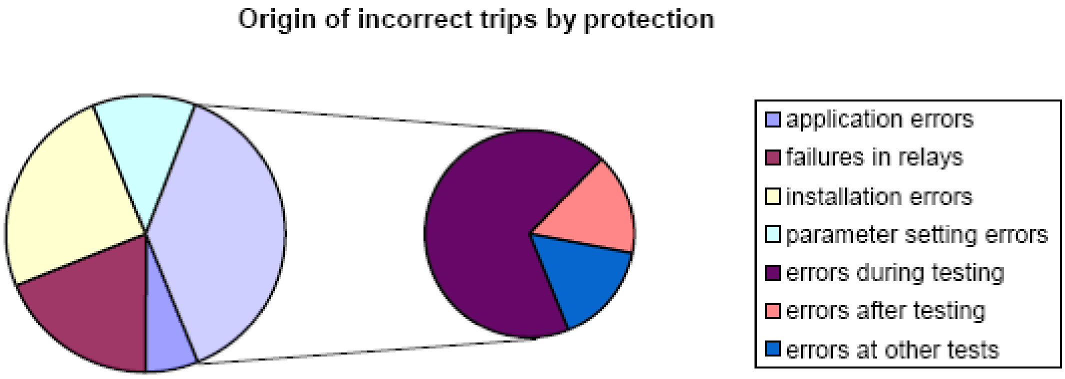

Figure 6.1: origin of incorrect trips by protection [3]

The term redundancy may apply to multiple protection systems with similar or varying functionality (fault detection and clearing speed), or to separate protection systems where failure of one system enables the other, or even to back-up protections in cases where system performance allows delayed fault clearing.

One approach that might be taken to reduce the probability of protection removing a line from service unnecessarily is to base line clearing on a voting system. Such an approach has been used on EHV lines on the WECC system (the western USA interconnection). However, even this is not always sufficient to balance off the considerations of protection design of dependability and security. For example, on the southeastern part of the WECC system in August 2002, distance protection of a key EHV line based on a voting scheme (2 out of 3) experienced a simultaneous maloperation of two of its three protection sub-systems. This precipitated a significant system disturbance. Prior to that, the scheme had cleared many faults successfully.

In order to determine optimal settings, the scheme had been extensively tested before being put into service, though the event in 2002 suggests that simulations cannot be relied upon to replicate all possible fault scenarios. As well as the event in 2002, false tripping of that same EHV line had been involved in some major disturbances in 1995 and 1996. This was the main reason for application of a 2 out of 3 voting scheme comprising of protection sub-systems with different models of relays.

Another example of 2 out of 3 logic for critical applications comes from Chinese experience, [5]. Out of step protection conceived for the North China remedial action scheme is based on local measurements and has the following design features:

- standard low cost hardware comprising industrial control computers;
- relays for detecting small currents on the lines;
- '2 out of 3' algorithms for initiating stability control logic;
- adaptive configuration with on-line settings modifications; and
- extensive built-in self-diagnostics.

Hydro Quebec, a major Canadian power utility, has also adopted a design philosophy for loss-of-synchronism (out-of-step) detection based on local measurements. The relays developed for this particular application use fuzzy logic and multi-criteria algorithms [6]. These novel relays are quite generic and can be used in other applications where detection of transient and dynamic instabilities is necessary. Two versions of them will complement the existing event based System Protection Schemes. The first is designed to supervise transmission lines to detect incipient loss of synchronism conditions; the second has an additional functional capability allowing accurate measurement of the rotational speed of generators. This allows faster determination of whether a generating station is approaching an out-of-step condition and gives more time for pre-emptive actions.

Nevertheless, the effectiveness of protection systems also strongly depends on the configuration of transmission substations. There are examples that significant system disturbances prompted review and redesign of bus arrangements to reduce the possibility of single points of failure affecting multiple lines or generating units e.g. 1996 Southwestern Public Utilities Commission).

6.3 Particular Protection and Control Issues

This section provides an overview of particular areas of protection and control applications that investigations of various disturbances have identified as common sources of problems or as potentially effective solutions.

6.3.1 Maintenance and Testing

Maintenance and testing of protection and control systems is one of the cornerstones assuring reliable performance of these systems. In recognition of the importance of this particular activity, regulatory organizations often put in place reliability standards or grid code requirements that stipulate obligations of various power system entities related to this activity. In addition, to assist the industry, specialized working groups and task forces provide references and guidelines with details on prevalent and proven practices.

One of the technical references on this subject, [7], sets out main principles and requirements associated with various maintenance approaches, such as performance based, time based, and condition based maintenance. Naturally, a distinction is made between different relaying technologies, especially considering their self-monitoring and failure detection capabilities.

Post-event analyses of major system disturbances often uncover gaps in procedures or work performed during maintenance and testing of protections.

Although important for ensuring proper performance of protection systems, maintenance and testing is invariably associated with risk. For example, in March 1996 during maintenance of bus differential protection at a major transmission station, an accidental trip removed out of service all seven EHV lines connecting Furnas power plant to the rest of the system and initiated a blackout of a large part of Brazil Blackout [8]. The Florida event in February 2008 [9] is another salient example of protection maintenance that went wrong.

A combination of a relay failure and a maintenance error that lead to a widespread power interruption in Colorado and neighbouring States is a scenario typical to many disturbances. A lighting strike caused a fault on a 345 kV line. Protection correctly opened the line at one end but failed to open the other end due to a combination of a faulty ‘A’ relaying and unavailable ‘B’ relaying, which was inadvertently left in the test position following maintenance. Clearing of the fault required tripping of a number of 230 kV lines, severely stressing the system that was already operating near its limits.

6.3.2 Line Protections – Zone 3 and Relay Loadability

Erroneous operation of line protection is notorious for causing system conditions beyond worst-case contingency criteria considered in system development and operations planning. The IEEE Task Force on Blackout Experiences points out [8] that inadequate response of transmission protection to increased power flows or damped oscillations perceived as faults has perpetuated many major disturbances and Blackouts.

A number of major disturbances and Blackouts were caused by cascaded loss of transmission lines due to operation of Zone 3 distance protections or other protections responsive to overload.

Consequently, this problem has instigated extensive work in search for more robust solutions. Following the 2003 Blackout, NERC's Blackout report [10] included a recommendation that zone 3 distance protection on all transmission lines above 230 kV shall be reviewed to assure that it is not set to trip on extreme overload during system emergency conditions. A joint US-Canada task force recommended expanding this review on all operationally significant 115 kV and 138 kV lines, including those that are part of monitored flowgates or interties [11].

6.3.3 Line Protections – Loss of Synchronism conditions

When two portions of an integrated power system start falling out of synchronism, the electrical centre of a swing occurs on particular lines, activating their distance protection systems. Such line protection operation may be deemed legitimate and desirable.

Nevertheless, as mentioned in Chapter 4, certain defence plans include controlled system separation with the intent to create viable islands with reasonably balanced generation and load. Such defence plans rely on opening of selected tie lines when respective portions of the system start losing synchronism. Those lines are equipped with out-of-step relaying that operates significantly slower than line's distance protection. Therefore, such schemes require blocking of distance protections for out-of-step conditions in order to be effective.

Controlled system separation schemes form an integral part of defence plans of many power utilities including those in France, Australia (Queensland), China, Canada (Quebec) and Japan (Tokyo area) [8].

6.3.4 Tie Line Re-closing

Automatic reclosing of major interconnections between portions of a power system separated by out-of-step conditions has proved to be a powerful means to mitigate the effects of major disturbances.

For example, during the August 2003 disturbance, some of the tie lines between Ontario and neighbouring areas of New York State managed to reclose at a particular moment during the transient phase bringing the system close to a stable equilibrium. Other tie lines were unable to reclose because the power angle between the connection points was too large.

Reclosing only takes place if a phase angle between two portions of the system is such that circuit breakers on the connection points between separated portions of the system can sustain it. The settings for the phase angles are also dependent on the reclosure torque experienced by nearby generators. In order to reduce the angle, operators sometimes attempt to redispatch generation or resort to rejecting additional load in the islanded portions of the system.

In 1998, a major disturbance affected large portions of Minnesota, North-western Ontario, Manitoba, Saskatchewan Wisconsin, North and South Dakota and broke the system into several islands. Subsequent investigation conducted by the regional reliability organization (MAPP) came up with a number of recommendations [12] including the need to consider bypass of synchrocheck relays to permit direct reclosing of critical tie lines.

The focus of the review was to determine if a phase angle for which reclosing would be allowed could be increased under emergency conditions. Nevertheless, it was concluded that this would not be feasible due to concerns about unwanted effects on generating units in the affected areas.

6.3.5 Overload protection

Overload or overcurrent protection is installed on overhead lines in most countries in addition to distance protection. Indeed, as well as being judged by engineers to be prudent in ensuring that breaches of system operating limits do not persist, it may be required by law as a safety measure to minimise the risk of flashover. On the other hand, in England and Wales, it has been argued that such protection on 400kV and 275kV overhead lines is unnecessary because of the very low risk of flashover before the operation of distance protection. At the same time, it is argued that overcurrent protection must be set to quite conservative limits that do not take account of ambient temperatures and wind cooling prevailing at the time of an incident thus meaning that overcurrent protection is usually tripped before the genuine thermal limit is reached. This then reduces the time available to the system operator to correct system emergencies before they are made worse by the trip of another circuit.

6.4 Coordination of defence measures

Secondary voltage control – such as deployed in France – has been argued to have a beneficial effect on the likelihood and extent of a system interruption (mainly because local generation voltage targets can be updated rapidly in fast-changing system situations). However, because of the risk of exhausting reactive power reserves at inappropriate times, any beneficial effects for system defence might only arise alongside other measures such as tap change blocking.

Co-ordination of under-frequency load shedding is difficult to achieve. In particular, the system operator cannot always be sure that the load shedding is minimised and will not, due to taking place in net exporting areas of the system, make problems associated with high power transfers worse. Any automated load shedding to relieve overloads can be difficult to design appropriately as overload conditions are often accompanied by under-voltage and there will be interaction with UVLS.

Black start capability at power stations is clearly important to the restoration of the system. However, it needs to be ensured that this capability is adequately distributed around the system and is always properly maintained.

6.5 Robustness of assumptions and the role of standards

It is extremely important that correct assumptions can be made about the characteristics of all aspects of the power system by system planners. Often, multiple parties are responsible for different aspects of a single, synchronous system:

- different transmission owners or system operators in different, interconnected geographic areas;
- in a particular geographic area, different parties responsible for transmission infrastructure development and maintenance, system operation, and development, maintenance and operation of generation.

The above multiplicity of parties presents a clear need for coordination of responsibilities. With regard to the relationship between a system operator and a generator, many electricity supply industries around the world have Grid Codes which define, for example:

- the performance capability that a generator must have in respect of, in particular, system frequency control, reactive power and stability;
- the data that owners of generation must provide to the system operator to enable them to verify that the system can be operated safely and securely.

As investigated by CIGRE Working Group C1.12, among others, Grid Codes may also specify security standards for system operation and planning, power quality requirements, outage planning rules, communication protocols and so on.

As an example, the Ontario Independent Electricity System Operator's (the IESO) Resource and Transmission Assessment Criteria [13] describes:

- the approach to system studies including selection of parameters and contingency criteria;
- acceptable pre- and post-contingency system conditions;
- connection criteria for generation, transmission and large load facilities;
- acceptable operating measures to counteract impacts of credible contingencies;
- criteria for resource adequacy assessments; and
- criteria for system restoration.

The document also provides an overview of recommended station layouts, recognizing that it is often not practical to use an elaborate mathematical approach to determine an optimal balance of the layout complexity, reliability and cost. In general, the station layout and the number of breakers are determined based on due consideration of the following:

- operating flexibility and reliability of the station configuration;
- probability and a typical duration of a failure;
- effect of a failure on the IESO-*controlled grid*; and
- impact of a failure on the affected load.

Certain planning, design and operational criteria are often defined at regional or international levels. For example, NPCC (North Eastern Power Coordinating Council) is an organization that defines regional reliability requirements for electric power utilities the North Eastern areas of United States and Canada. It provides a forum for member utilities to work jointly on identifying issues, developing reliability measures and implementation programs that have impact beyond local areas.

NPCC has adopted a sophisticated engineering methodology [14] for identifying those elements of interconnected power systems that are critical to the reliability of the Region. The methodology centres on system studies and comprises both power flow and transient stability analyses. The goal is to determine whether faults on particular buses have significant adverse impact on the power system's performance beyond a local area.

It will be essential for transmission planners and operators not only to have accurate models of their own equipment but also of that of other parties connected to the system that will have a significant influence on its behaviour. Some issues associated with accurate modelling of the system are discussed briefly below followed by some considerations in relation to enforcement of the requirements of Grid Codes and other relevant standards.

6.5.1 System monitoring and event analysis

Analysis of system performance following severe disturbances or major power interruption events is of particular importance for the development of mitigation measures. Typical activities include:

- identifying underlying causes and common characteristics of particular incidents;
- evaluating power plant ability to ride through frequency and voltage transients;
- reviewing performance and coordination of control and protection systems including SPSs; and
- examining the effectiveness of emergency response plans and system restoration procedures.

All this requires in-depth understanding of the characteristics of various types of generating facilities, transmission elements and loads and the nature of their interaction.

Analyses of power system disturbances provide material for re-evaluation of system operating limits, for the development of defence plans, for improving facility designs and control and protection systems. Furthermore, the analyses of major disturbances often result, as was the case following the Blackout of August 14th 2003 [10], in an extensive effort to enhance and enforce regulatory reliability obligations through mandatory standards.

In a liberalised electricity supply industry, regulatory authorities have an especially important role to play in enabling learning of lessons from events. For example, NERC, in performing its role as a

North American Electric Reliability Organization, has an obligation to conduct periodic reviews of selected bulk electric system disturbances and unusual occurrences. The reports are published on the site http://www.nerc.com/elibrary.php. The objectives of this work include:

- sharing the experiences and lessons that North American utilities have learned;
- examining if Reliability Standards and Operating Policies adequately address the normal and emergency conditions that can occur on bulk electric systems; and
- evaluating potential violations of the requirements of NERC's Reliability Standards. (This became particularly important after the Standards were adopted as mandatory and enforceable in 2006).

Some of NERC's recent findings related to generation facilities are discussed in Chapter 5 of this Brochure.

Disturbance monitoring and event recording capability is critical for effective post-mortem analysis of major power system disturbances. Nevertheless, even nowadays this capability appears to be not quite adequate. It has not been unusual that lack of usable data hindered the analysis of major disturbances, e.g. [15].

Investment in monitoring equipment and event recording systems requires planning and justification and may be argued to be not overly prohibitive relative to the benefits in terms post-event analysis and the facilitation of future measures to manage major disturbances. However, experience suggests that, as was the case in England and Wales in the 3rd Transmission Price Control, it may be difficult to gain regulatory acceptance for it[13].

6.5.2 Accurate modelling of the power system

Dynamic analyses are indispensable in investigating and understanding the complex phenomena that occur during power system interruptions and to identifying, specifying and defending investment in defence measures. However, according to some recent surveys [18], dynamic studies are carried out only occasionally rather than as a routine process. The survey identified the following major hurdles:

- human resource problems;
- lack of data; and
- lack of expertise.

Overcoming these hurdles requires planning and investment in

- the development of suitable specialised human resource; and
- the collection and verification of data, in particular the characteristics of the network and of generation connected to it. (See the discussion on compliance and testing in section 6.5.5 below).

Analyses of major disturbances often reveal inaccurate models or models lacking the level of detail needed to reconstruct the event with an acceptable degree of replication. NPCC's working group SS38 found this to be the case in their study of dynamic performance of interconnected power systems during the August 2003 disturbance in North America [16]. In attempting to reproduce, in a simulation, the disturbance and the way islands formed and how each island subsequently behaved, the working group found the following problems.

[13] In this instance, the transmission owner in England and Wales – National Grid Company (NGC) – had argued that new monitoring was required. While NGC based its argument around ensuring adequate standards of power quality, it would also have had significant benefits for analysis of major unreliability events. The regulator – Ofgem – made no allowance in the price control settlement for such expenditure, arguing that it had been insufficiently well justified [16].

- a lack of accuracy and precision in the sequence of events. In particular, additional information on generating unit trips was necessary to differentiate between the event times for turbine control action and the operation of generator protection.
- a lack of dynamic data recordings.
- a lack of accuracy in the initial load flow case from which dynamic simulations were launched, in particular in respect of reactive power, load power factor, and voltage profile.
- lack of confidence in the modelling of mid-term dynamics and the system response to disturbances that propagate over a significant time period.

A particular issue highlighted was that of load modelling which continues to be a critical component in analysis of major disturbances with large frequency and voltage excursions.
In addition, the working group emphasised need for investment in monitoring equipment and the importance of load modelling while other post-event analyses have pointed to a need for new simulation tools, e.g. [4].

In the survey executed during preparation of CIGRE Brochure 312 [18], the participants highlighted particular difficulties in performing dynamic analyses. Identified problem areas and deficiencies (in order of priority):

- models for wind farms;
- models for new network equipment;
- models for dispersed generation (equivalent dynamic models for transmission studies);
- models (especially dynamic) and data for loads;
- correct generator model parameters; and
- models of open cycle and combined cycle Gas Turbines.

This list can be extended to include modelling of longer term dynamics, outer loop controls and various excitation and governor limiters. Particular area of concern is how to assess and model spinning reserve, especially in investment planning studies.

Reference [19] focuses on issues around assessing and modelling properly the available spinning reserve. It accentuates the criticality of having realistic expectations in terms of available generation to support frequency recovery.

An important feature in the collection of adequate data is the role played by standards in obliging different parties to make it available. (The coordination of standards is addressed in the next section below).

Notwithstanding the above observations, a dilemma remains as to how far to pursue more detailed and complex modelling and how much emphasis to put on high fidelity replication of disturbances.

6.5.3 Coordination of standards

While Grid Codes and reliability or security standards worldwide have much in common, there are difference in detail that can sometime be significant. When more than one standard applies on different parts of the same interconnected system, there is a risk that incorrect assumptions will be made by operators about what will happen outside of their immediate area of jurisdiction. Furthermore, as was discussed in chapter 3, on an interconnected system, it is important that the impact of secured events outside a system operator’s area of jurisdiction is properly considered and, to ensure equitable treatment of consumers and participants in a common electricity market in different areas, that acceptable and unacceptable conditions are consistently defined. Such consistency will also help different entities to contribute effectively to management of disturbances that might affect the whole interconnected system and to provide clarity on what penalties might imposed in the event of either failure to take action or the interruption of load.

Such arguments have been recognised by different organisations that have been seeking to develop common standards for reliability, for data exchange and so on for application across wide areas, e.g. NERC and UCTE. They were instrumental in driving Great Britain towards adoption of a single 'GB Security and Quality of Supply Standard' and a single GB Grid Code with the merger of the electricity markets in Scotland and in England and Wales in 2005 [20].

It is also important that market rules are consistent with engineering standards and best practice. For example, in Germany, system operators are obliged to take only the cheapest actions; more expensive ones are undertaken only if proved to be necessary. However, such proof is often very difficult to provide in emergency situations when sound engineering judgement suggests that more expensive actions are necessary.

6.5.4 Standards in a liberalised industry

The various standards applied in an electricity supply industry are living documents, reviewed and refined on a periodic basis to accommodate changes in regulatory framework, system conditions or operating requirements. They are the result of collective industry experience, knowledge and needs.

In the past, centralized mainly publicly owned electric power utilities had vested interests in power system reliability and their vertically integrated structure gave them the power to coordinate the various factors that contribute towards it. Furthermore, there were reliability organizations on a regional level that were developing specific criteria, guidelines and procedures of interest for integrated power pools. This was a joint initiative of the electricity industry and although compliance was voluntary, it worked for many years.

Restructuring and deregulation of the electricity industry has placed new pressures on voluntary compliance. Many newly created utilities became commercial entities with a primary focus on providing return on investment to their shareholders. Power system planning, operation and reliability in general, became the responsibility of specialized non-profit organizations or government agencies which, however, operate at arms length from other segments of electric power industry. Reliability requirements and commercial drivers, being divergent by nature, seem in many instances to have started to fall out of synch.

From a North American perspective, several major disturbances and most notably the Blackout of August 14th 2003 have revealed serious weaknesses in the voluntary approach to power system reliability. The final report of the U.S./Canada Blackout Task Force recommended creation of an organization termed ERO (Electricity Reliability Organization) with a mandate to develop and ensure enforcement of reliability standards for bulk power systems. NERC assumed this role since it was already providing the necessary framework for reliable planning and operation of power systems throughout North America. Canadian jurisdictions signed memorandums of understanding (MOUs) with NERC stipulating relationships between various regulatory bodies.

In such a situation and if consumers' concerns for reliable supply of power are to be satisfied, new standards would seem to be required. Furthermore, they would seem to need some 'teeth' to ensure compliance.

6.5.5 Ensuring compliance

There are two ways in which certainty regarding generator performance helps manage system security. The first is that defining generator performance allows the system operator to more confidently predict the response of the power system to disturbances. Of course, this is true only if the advised level of performance from the generator matches its actual capability.

The second benefit of having defined generator performance obligations is that the generators then have a clear performance expectation which they can ensure they deliver.

Around the world, different models might be used for governance and enforcement of standards such as grid codes and reliability standards. With so many different parties having a stake in those standards, the questions of who has responsibility for development and maintenance of standards and who has the authority to approve changes become extremely important.

Regulatory bodies have a key role to play and first versions of standards are usually based on established custom and practice. For example, in France, a lot is asked of generators in terms of capability. In Great Britain, while the Office of Gas and Electricity Markets (Ofgem) has responsibility for giving (or denying) approval to proposed changes, the proposals are developed by a 'Grid Code Panel' comprising, in the main, the system operator and representatives of owners of generation. Since the latter are primarily concerned with minimising the cost of generation, it is often difficult to reach agreement within the Panel on changes that the system operator argues are in the best interests of consumers.

Another issue concerns verification that all parties are complying with standards and who is responsible for providing that verification. This should be kept in mind when a standard is being developed: can compliance with its criteria be adequately verified, and are its requirements sufficiently unambiguous that it is clear when action against non-compliance is justified?

NERC publishes annual reports on generator performance. Reference [21] discusses a tool developed by the system operator in France – RTE – for continuous monitoring of transmission connected generation. It also describes the introduction of ancillary service contracts that remunerate generators for performance but also penalise them for failures.

It might seem obvious that, in the event of generators proving reluctant to comply with requirements, strong penalties are required. However, experience from Britain and Australia suggests that designing an effective regime to encourage compliance needs careful consideration. Extremely high penalties may have unexpected results such as:

- making regulatory authorities reluctant to impose them;
- encouraging generators to minimise the declared performance capability of their plant;
- discouraging open communication between generators and the system operator regarding changes to the capability of their plant;
- fostering an adversarial climate in which generators are focused on the need to defend themselves against accusations of non-compliance; and
- increasing the burden of proof for the system operator or the regulator.

'Commercial' arrangements where generators are paid for good performance (which provides an encouragement to a generator to volunteer for monitoring, even if that performance is actually a minimum requirement) and collaboration in working through causes of non-compliance might be more effective.

In the end, an open exchange of information is key to containment of major unreliability events; anything that blocks or hinders that is inadvisable.

6.6 Other issues

Other issues may also be considered to be pertinent to the question of coordination of facilities and procedures to maximise system resilience against major disturbances and recovery from them. Among these are the following, which have not been addressed by WG C1.17.

- issues associated with an operator being able to demonstrate the prudence of actions taken;
- the use of transmission spares and sharing of such resources between utilities; and
- assurance of the reliability of low voltage supplies to substations, in particular for protection and control systems;

- the contribution that rapid manual or automatic switching of loads between grid supply points at a sub-transmission or distribution level might make to the limitation of impact of loss of supply events, the importance of this for realisation of ‘smart’ or ‘self-healing’ grids and the extent to which it is limited by currently available techniques for reliable identification of fault location.

6.7 References

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7 Justification of Investment in Containment Measures

7.1 Introduction

Investments in general tend to be undertaken with a view to a return to the investor. This return is usually economic or financial and can be quantified, albeit based on certain presumptions or predictions. In some cases investments are made for strategic, environmental or social reasons, in which case the benefits are less tangible or even remotely apparent.

Investments in electricity transmission are in a sense no different from other forms of investment activity, but inadequate investment can have very different and far reaching consequences that can directly impact upon society and the economy of a country.

Electricity transmission investment within utilities is explicitly or implicitly based on the reliability of supply to the end consumer. Where it is explicit, the reliability is often based on a 'deterministic' criterion of, for example, *N*-1 which means that for a single event (say, fault outage of a single circuit or pair of circuits) there shall be no loss of supply to the consumer. (See Chapter 3 above for a discussion of meanings of reliability and security). The deterministic criteria might have evolved over the history of a utility, or perhaps imposed by some regulatory authority. The cost benefit of such investment criteria is often not known, usually because the cost of power supply interruption is not easily determined. This approach is also compounded if the reliability of the network is also difficult to determine.

For many utilities around the world, investment in transmission capacity for the normal meeting of demand or facilitation of electricity markets is required to be based on an explicit cost-benefit analysis (CBA). This requires analysis of a wide range of operational and market scenarios and consideration of the probabilities of each, even though 'deterministic' system security or reliability criteria may still be considered.

With electricity supply industries worldwide becoming increasingly focused on decentralisation of management, facilitation of competition between generators, choice for consumers and access to private investment, there has been an increasing attention paid by regulators to those activities that remain undertaken by monopoly providers, such as transmission ownership and operation. This attention has often been with the express purpose of safeguarding consumers' best interests, the main threat to which, as usually perceived by regulators, has been excess cost. Thus, regulators, such as those in Australia and New Zealand, require clear economic justification of any investment for whatever purpose, including management of major unreliability events.

This chapter considers the fact that investment in measures for containment of major unreliability events is often difficult to justify on a cost-benefit basis, mainly for two reasons:

- the cost to consumers of interruption to supply or their benefit from continuity of electricity supply are hard to quantify for any given unit of energy;
- the probabilities of major unreliability events either being extremely difficult to determine or being estimated to be so low that the expected benefit of the proposed investment ends up also being very low.

Nonetheless, experience suggests that consumers, governments and regulators pay close attention to and are dissatisfied with failures to prevent or contain major unreliability events. Experience also suggests that utilities are well able to demonstrate the value of measures that are already in place when events are successfully contained. (Some cases of successful operation of defence measures were discussed in relation to a number of major unreliability events in Chapter 2; reports from utilities contacted by WG C1.17 of successful operation are also noted below).

7.2 Cost of Electricity Interruptions

Quantification of the cost of supply interruptions is a complex issue that depends on the types of customers, expectations of reliability of supply, the perceived value of energy not supplied and the time, frequency and duration of interruptions. Studies and reviews have been conducted by many interested bodies, for example by CIGRE [1] in 2001 and Lawrence Berkeley National Laboratory [2] in 2004. The Berkeley study followed the massive North American blackout in August 2003, and came up with an estimate of $80 billion annually, with a range of $23-$135 billion. A large portion (67%) is due to momentary interruptions compared to sustained ones, with commercial customers bearing the brunt of it (72%).

There are also the ‘knock-on' effects of blackouts which are difficult or impossible to quantify such as crime and transport infrastructure. In the July 1977 New York blackout, looting and arson was rampant, especially in the poorer neighbourhoods. To quote a media report [3]:

> "In all, 1,616 stores were damaged in looting and rioting. 1,037 fires were responded to, including 14 multiple-alarm fires. In the largest mass arrest in city history, 3,776 people were arrested. Many had to be stuffed into overcrowded cells, precinct basements and other makeshift holding pens. A Congressional study estimated that the cost of damages amounted to a little over US$300 million".

The value of lost load (VOLL) can be difficult to evaluate as it can vary tremendously with different scenarios and circumstances. A basic estimate of VOLL in 1998 – based on gross domestic product divided by annual energy supplied – came up with $2420/MWh [4]. However, a 1978 US Department of energy study of the New York blackout estimated that the cost, including damages due to arson and looting, equated to about $10,000/MWh. Survey work undertaken in the UK in the mid 1990s suggested a value that would be equivalent to about $20,000/MWh now [5]. The value put on actions undertaken by transmission owners in Britain to reduce annual unsupplied energy equates to about $60,000/MWh [6]. In Australia, the market price cap at time of writing[14] is set at $12,500/MWh while, for justifying transmission reinforcements in the state of Victoria, the Australian Energy Market Operator used a value of customer reliability of $55,000/MWh. Others have suggested that the value placed on lost load should reflect the ‘gross value added' of the affected consumers [7].

In the August 2003 North American blackout which affected over 50,000,000 people, there was however little crime reported. In Ottawa, police reported 23 cases of looting and two deaths possibly linked to the blackout – a pedestrian hit by a car and a fire victim. Six other fatalities were also reported, one in Connecticut and five in New York City [8].

Infrastructure affected includes water supply where low water pressure could result in contamination of water; consequently customers and business like restaurants have to boil before use. Air, rail and road transport are also affected by power failure, causing inconvenience and additional costs to consumers and industry alike. In the aftermath of the blackout, even though supplies have been restored, there were problems due to the need to conserve energy and some industry were not able to return to full production till several days later. All these issues add to the ‘hidden' cost of supply interruption.

7.3 Investment in Capacity

On the face of it, the $80 billion noted above to be sustained annually in North America would seem to be ample reason for improving reliability. However, investments by utilities in North America, for example, depend on whether there is a cost benefit to the utility. (In the absence of economic penalties on utility failure to meet demand for power, the cost of supply interruption to a utility's customer is

[14] The market price cap in Australia is regularly reviewed.

not the same as the cost to the utility, and the incentive to invest may not be there). As noted above, investments in many other places depend on demonstration of a cost-benefit to consumers. The only exception is when an investment is imposed by the Regulator or there is a statutory requirement.

Economic criteria vary with utilities and are subject to occasional updates. The Network Code section of the South African Grid Code applied by Eskom was amended in March 2008 and effected the following main changes in respect of investment [9]:

1. N-1 is the minimum redundancy standard on a deterministic basis.(Section 7.6.3)
2. The definitions of the investment criteria have been clarified and extended (Section 7.7), largely to accommodate refurbishment projects which were extremely difficult to justify in terms of the old rules.

The economic criteria applied by Eskom are also embodied in the South African Grid Code [9]:

a) Least Economic Cost Investment

The value of improved quality of supply must be greater than the cost to the service provider to provide the improved quality of supply.

b) Cost Reduction Investment

Operational cost reduction results in the proposed investment having a lower lifecycle cost than continuing with "business as usual". The cost reduction is usually the result of a reduction in network losses caused by an expansion investment, or a reduction in maintenance costs for an asset replacement or refurbishment investment.

c) Statutory Investment

Required to meet legal requirements, irrespective of whether any financial benefit is likely to accrue. This applies to compliance with all legal requirements, but in practice mainly to safety or environmental regulations.

d) Strategic Investment

Discretionary investment to ensure the longer term sustainability of the business. This includes site and servitude acquisition, asset replacements in accordance with an asset lifecycle management plan, and expansion related investments needed to satisfy the minimum N-1 deterministic redundancy requirement that cannot be justified using the Least Economic Cost or Cost Reduction methods.

Customer interruption costs (CICs) are used in the calculation under the 'Least Economic Cost' criteria to work out the cost of unsupplied energy using probability of fault event. CICs used by Eskom [10] come from customer surveys and shows that industrial and commercial costs are about 8.7 times and 6.7 times greater than residential costs respectively.

In Great Britain, network investment is (at time of writing) based on the National Electricity Transmission System SQSS (Security and Quality of Supply Standard) [11] which is a set of mainly deterministic minimum criteria, though reliability (hence probability) is taken into account in any economic justification for a variance in scheme design and/or operation. In investing under SQSS there is usually more than one option to consider and cost comparisons are then relative. But investing under economic criteria where the option of 'doing nothing' is a consideration, the cost of such an option where blackout occurs is harder to estimate.

7.4 Survey results

Chapter 4 described some common defence measures that can be used to mitigate against different collapse mechanisms. Given the difficulties of justifying investment in containment measures such as system defence, a survey to determine utilities' experience of using such facilities and justifying investments in them was conducted by WG C1.17. The survey covered:

- Main system defence measures including
  - Special Protection Schemes (SPS);
  - Under Frequency Load Shedding (UFLS); and
  - Under Voltage Load Shedding (UVLS).
- Other facilities often classed as being part of system defence such as
  - islanding;
  - transformer tap blocking;
  - generator trips/start according to system frequency.
- Other containment measures, mainly
  - restoration plans
  - black start facilities

This section reports the main results of the survey in respect of the installation and utilisation of measures. The next section discusses the ways in which investment in them was justified.

7.4.1 Most widely used defence measures

The table below summarises the number of responses in the survey in respect of the most widely used system defence measures.

Measure	No. of utilities with the measure	Dates of installation	No. of schemes used	No. that operated successfully
Special Protection Scheme	12	1978 to 2009	12	7
Under frequency load shedding	15	1960s to 2007/8	16	15
Under voltage load shedding	7	1990s to 2007	2	1

7.4.2 Other defence measures

Other measures installed by the 10 utilities with positive replies:

Type of scheme	**Number of utilities**
Islanding	2
HVDC link with overload and undervoltage regulation	1
Generator tripping to house load	1
Under frequency starting of gas turbines	2
Under frequency tripping of pumping load; starting of pump storage	1
Tap-changer and secondary voltage control	1
Over frequency tripping of hydro units to own auxiliaries	1
Auto starting of synchronous compensator	1
Hydro unit tripping based on active power, transient and dynamic oscillations	1
Fast run down of pump storage; maximise output on under frequency	1

a Most were installed in 1980s and 90s.
b 4 (40%) were required to meet planning/operational standards.
c No reply stated that cost benefit analysis was a consideration; in some cases this question was not applicable.
4 (40%) reported that reliability was taken into account
1 (10%) stated that security was the reason for the choice.
d 3 (30%) were implemented because of Regulator/government,
1 (10%) was due to cost advantage, with probability of event given as 1 in every 50 years.
1 (10%) cited financial incentives.
e 2 (20%) cited significant interruptions prior to decision to invest, with 1 interruption quoted by one reply.
f 7 (70%) had been called to operate, with successful operation in all cases.

7.4.3 Other means of containment

It was noted in Chapter 4 that 'management' of power interruptions includes minimisation both of the initial power interrupted and the restoration time. Pre-developed plans for restoration and the provision of reliable and appropriately located black start facilities aid this latter aspect greatly. The survey therefore invited comments from utilities on these considerations.

Black start

The table below summarises survey responses in respect of black start facilities. Of the 15 utilities that responded, only one did not have any black start facilities. Each utility's total black start capability relative to peak demand ranged between 3% and 35%. 12 utilities reported a regulatory, governmental or Grid Code requirement for black start. Six utilities reported having experience with black start. Of these, five said that the facilities operated successfully while the 6th made no comment.

Plant used for black start	No. of utilities using that plant	Plant capacity relative proportion of total black start capability	Testing frequency
OCGT	7	8% to 99%	Between once per month and once every 2-3 years
CCGT	4	Between 8% and 100%	Between once a year and once every 4 years
Fossil steam	4	Between 40% and 73%	Between twice a week and once every 5 years
Hydro	7	Between 13% and 100%	Between twice a year and once every 2 years
Diesel	1	Less than 1%	
Nuclear	1	27%	Once every 5 years
Part reliance on neighbouring systems	3		
Other	1		

Restoration

15 utilities responded to the invitation to comment on their restoration plans. From these responses, the following observations may be made:

- 9 utilities require restoration plans because of external standard or regulation. (One utility had experienced significant interruption once prior to the decision to invest in various restoration facilities).
- planned restoration times vary greatly, from 10% within 3 hours to 80% within 24 hours, with one utility quoting 12 hours for complete restoration.
- 12 utilities reported testing their plans with the frequency of testing varying between once every 5 years and 6 times a year.
- 8 utilities carry strategic spares to aid restoration.
- 9 utilities co-ordinate their restoration with neighbouring utilities and 6 utilities have agreement to assist each other with manpower. 5 utilities have joint rehearsals with neighbours.
- utilities have a nominated central control if blackout is across more than one utility.
- 8 utilities had operated their restoration plans, all successfully.

7.5 Investment in Defence Measures

Defence schemes are different from the main network investments insofar as they are applicable to low or very low probability events. Though the probabilities are low, the effects are high as large areas could be blacked out, as can be seen in the various events described in Chapter 2 above. For the same overall levels of transfer of power, reliability can technically be increased by building more circuits and/or power stations. However, these means are more expensive than defence schemes; they are also harder to attain due to difficulties in obtaining planning consents. Besides, additional network headroom is often rapidly used up as the market exploits the ‘spare’ capacity and takes the system back towards its operational limits. Meanwhile, market, environmental and regulatory factors are forcing utilities to operate more in interconnected modes, with the consequential increase in the risks of widespread blackouts.

As noted in the introduction to this Chapter, investments in containment measures can be difficult to justify in cases where the probability of collapse is very low or indeterminate. In cases where the probability of occurrence is high or a certainty, defence measures are often more economic than main network investment options like, for example, a new circuit.

The following subsections present some discussion of the different justifications cited in the WG C1.17 survey for investment in system defence or other containment measures.

7.5.1 Compliance with statutory or regulatory obligations

A vast majority of the SPS (82%) and UFLS (75%) reported in the survey were said to have been installed because of planning and/or operational standard requirements. Other reasons why these schemes were installed varied from ‘historical’ to ‘being imposed by Regulator’. So it would seem that, based on the survey results, justification of defence schemes has not hitherto generally been an issue as the criterion is ‘compliance with operational and/or planning standards’. However, in light of regulatory trends observed recently, such justification might not always be available. Indeed, some utilities have already had experience of relying on other justifications, not least with respect to economic criteria and quantification of the value to consumers.

7.5.2 Cost Benefit

For some investments, it is possible for it to be shown to have a positive return after a period of say, 15 years (or whatever the scheme life is) taking into account the probabilities of interruption events, costs of interruptions of supplies, the restoration times, and the number of customers affected. As noted in section 7.3 above, the cost of interrupted supplies might be estimated from customer surveys, government or regulator's figures, or industry wide figures if available. Case studies or analytical techniques can also provide costs. In Britain, a transmission network reliability incentive scheme operates such that National Grid is rewarded on a sliding scale (up to 1% of operating revenue) if total loss of supply in a year is less than an agreed figure and is penalised (up to 1.5% of revenue) if in excess of a certain value. The figures for 2008 equated to approximately £48,000/MWh or about $60,000/MWh [6].

In practice, such investments tend only to be identifiable for 'local unreliability' where the probabilities of events and their consequences are quite easy to predict. In respect of containment of major unreliability events, other means of justifying the investment would seem to be necessary. However, WGC1.17's survey has shown that a number of utilities have either articulated cost-benefit cases for containment measures or used assumed probabilities of major events. For example, of the 15 respondents with SPS, 6 say they took cost-benefit into account when deciding to install the systems. One of these used a value of lost load, based on a full system collapse. Three respondents cited probabilities of events, between 1 every 2 years and 1 every 10 years. However, it should also be recognised that the main reason cited for installing SPS was not 'system defence' as such but avoidance of conventional transmission capacity through new or uprated lines. (Only one respondent cited, as the reason for the SPS, 'minimising customer interruptions').

Cost-benefit was also claimed to have been taken into account in 3 of the 15 survey responses received in respect of under-frequency load shedding. All three of these used assumptions on value of lost load; the considerations of load lost varied between 70 and 100 times the cost of normal load. The assumed probabilities of major events requiring use of under-frequency load shedding were between once in 3 years and once in 3-6 years.

In respect of the 7 responses from utilities that had installed under-voltage load shedding, only one cited consideration of cost-benefit in the investment. (The value of lost load considered to be the same as that of normal load. and the probability of being required as once every two years).

7.5.3 Strategy

Where a clear-cut economic case is not evident, a strategic case can be made for it if it can be shown that the investment cost is relatively modest compared to the potential economic and political cost of a widespread blackout, albeit that such a probability is very low and is indeterminate with any degree of confidence. In other words, the investment is justified regardless of the probability of occurrence of the major unreliability event and is concerned with, in effect, minimising the regret associated with not undertaking the investment [12,13]. That is, where the *possible*, as opposed to probable, consequence of the decision not to invest is much greater than the cost of the investment, the investment is undertaken.

An example of an investment in which the above type of argument played an important part is described in Chapter 8.

7.5.4 Response to an event

The last main reason for investment in defence measures identified in the survey was in response to a significant event. This was cited by 9 out the 16 survey respondents that had installed under-frequency load shedding and by 3 out of the 7 utilities that had installed under-voltage load shedding.

7.5.5 Discussion

Since the survey had returns from 15 utilities, the results cannot be regarded as definitive. However, some general observations are possible, For example, defence measures are largely put in place because of operational and/or planning standards; this seems to suggest that they are installed as an economic alternative to 'normal network reinforcement', or that their standards call for the installation of defence measures as a 'last resort' scheme.

Judging by the range of responses received, defence measures are difficult to define. Some utilities deem automatic voltage control like SVCs or tap-changing as defence measures, though it can also be argued that only schemes which are a 'last resort' should be classified as defence measures.

Depending on the definition, some measures may be easier to justify under planning/operational standards than as 'true' defence schemes. Futhermore,

- power interruptions prior to installation of appropriate defence measures are an added reason for many utilities to install defence schemes.
- a large majority of SPS schemes (>65%) took cost benefit analysis into account as compared with less than 20% for either of UFLS or UVLS schemes. However the vaue of lost load (VOLL) played a minor part in this cost benefit. This is perhaps not surprising as VOLL is rather difficult to determine.

Assumed frequencies of major unreliability events seem rather high; they certainly are if the consequences are always to be taken as the loss of between 70% and 100% of demand were defence measures not present. Since the authors of this Brochure had made a commitment not to reveal the identities of each respondent, which systems these responses correspond to cannot be reported here, but to the authors' knowledge, in an at least some cases, they seem to be higher than history would suggest.

It is possible that what a number of respondents were reporting was the number of occasions on which special protection schemes operated. For example, in Australia, events that trigger response from under-frequency load shedding (UFLS) relays occur, on average, once a year. However, due to the successful action of UFLS, these occurrences are generally not associated with major unreliability events. On the other hand, in Britain in May 2008 (see section 2 above for a description), the necessity of operation of ULFS was regarded as an indicator of a significant event having taken place and as a trigger for a major investigation. A general conclusion is that any probabilities of major unreliability events – whether historic or assumed – must be treated with circumspection by virtue of their rarity.

One conclusion that can be drawn is that the best time to put forward a case for investment in defence measures is soon after a major unreliability event. While this is not surprising, it might also be argued that engineers should be capable of making, and approval authorities capable of recognising, a convincing case based on cost benefit, technical performance or strategic requirements.

7.6 References

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8 Planning, justification and implementation of containment facilities: case studies

8.1 Introduction

This Chapter presents a number of case studies intended to illustrate some of the issues addressed elsewhere in this Brochure. One of the benefits of case studies is that particular questions that cannot be addressed generically can nevertheless be highlighted and provide useful background that might be applied in other contexts.

The case studies presented below concern the following:

- the development of a defence plan for a very large, interconnected system operated by a large number of different entities (the UCTE system);
- the conception of automated and pre-planned islanding (Romania);
- specific issues associated with the development of new defence and restoration plans for a system on the periphery of a large interconnection (Turkey);
- the justification of investment in transmission capacity by reference to avoidance of vulnerability to a major unreliability event (New Zealand);
- the justification of investment in a liberalised electricity supply industry in a particular defence (England and Wales);
- defence and restoration for a system with a high reliance on nuclear power stations (France)
- ‘cyber security’ (North America).

Other case studies can be found in reports such as [4][3].

8.2 Development of a UCTE Defence Plan

As has already been summarised in Chapter 2, on the night of 4th November 2006 the UCTE interconnected grid was affected by a serious incident originating from the North German transmission system that led to power supply disruptions for more than 15 million European households and a splitting of the UCTE synchronously interconnected network into three areas. The immediate action taken by all Transmission System Operators according to the UCTE security standards prevented this disturbance from turning into a Europe-wide blackout. However, this event ranks among the most severe and largest disturbances in Europe [5].

In the immediate aftermath of the incident an investigation committee was set up which came finally to the recommendations listed in Table 8.1, the responses to which are the subject of the case study described in this section.

Table 8.1: recommendations following investigation of November 2006 UCTE incident [5]

Recommendation #1
The application of the N-1 criterion in Policy 3 of the UCTE Operation Handbook has to be reviewed in terms of the following aspects:

- Definition of the relevant part and specific conditions in the adjacent systems which have to be taken into account in TSOs security analyses.
- Simulation of contingencies (tripping of power system elements) located outside the TSO's own control area.
- Mandatory and regular online contingency analysis (N-1 simulations) connected to the alarm processing system.
- Preparation and regular check of the efficiency of remedial actions through numerical simulations.

Recommendation #2
Policy 5 ("Emergency Operations") has to be extended with a "Master Plan" defining principles of operation and TSOs' responsibilities to manage UCTE-wide or regional disturbances. Additionally the following aspects have to be considered:

- TSOs have to reconsider their defense plans and load shedding philosophy and rating taking into account significant amounts of generation tripped during disturbances with large frequency deviation
- The restoration and re-energization process has to be explicitly coordinated by TSOs regarding DSOs actions and the related responsibilities and duties of involved parties must be clarified within a national framework

Recommendation #3
UCTE has to develop standard criteria for regional and inter-regional TSOs co-ordination approach aiming at regional security management, from operational planning to real time, in terms of joint training, enhancement of exchanges of data, results of security analyses and foreseen remedial actions.

Recommendation #4
UCTE has to set up an information platform allowing TSOs to observe in real time the actual state of the whole UCTE system in order to quickly react during large disturbances.

Recommendation #5
The regulatory or legal framework has to be adapted in terms of the following aspects:

- TSOs should have the control over generation output (changes of schedules, ability to start/stop the units)
- Requirements to be fulfilled by generation units connected to the distribution grid should be the same in terms of behavior during frequency and voltage variations as for the units connected to the transmission network. These requirements should be applied also to units already connected to transmission and distribution grids.
- Operators of generation units connected to the transmission grid must be obliged to inform the TSO about their generation schedules and intra-day changes of programs prior to their implementation.
- TSOs should receive on-line data of generation connected to DSOs grids (at least 1-minute data)

Many of these recommendations concern the need for better coordination in UCTE between TSOs, DSOs and generation units (see Chapter 5). With recommendation #2 it is required and thus justified that Transmission System Operators reconsider their defence measures.

In the basic considerations and action plan for managing UCTE wide disturbances [3] it was proposed to proceed as follows:

- to classify stability problems according to CIGRE and as demonstrated by past major incidents in UCTE;
- to analyse the performance of line protection system in abnormal system conditions;
- to review defence plan procedures;

- to establish a UCTE wide defence plan taking into account the following technical requirements:
  - o consideration of the stability phenomena as defined by CIGRE;
  - o activation according to predefined criteria (stability margins);
  - o prevention of voltage and frequency deviations which are beyond the robustness of generation units (grid requirements);
  - o decentralised implementation;
  - o UCTE wide harmonisation;
- review of generation unit Grid Code requirements;
- review of Restoration Procedures with special attention paid to the resynchronisation of larger parts of the interconnection.

At time of writing, the review of defence measures within UCTE has been completed by means of a questionnaire and the classification of stability problems the analysis of line protection system performance under abnormal system conditions have been finalised. The next step is to harmonise the defence measures as far as possible.

The review of restoration procedures with respect to the resynchronisation of larger parts of the interconnection is regarded as being of particular importance as a result of several unsuccessful attempts in the course of the 4th November incident. In order to analyse the physical effects and to permit the development of recommendations, simulation models can be used provided they succeed in adequately reproducing the actual system conditions. An example of simulation of the 4th November incident is shown in Figure 8.1.

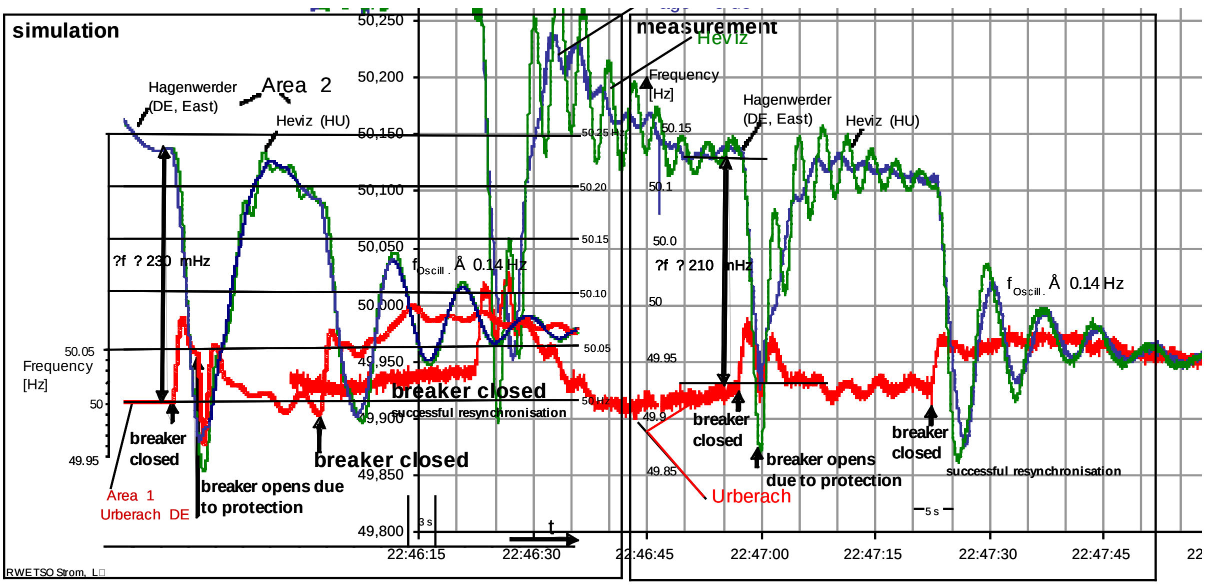

Figure 8.1: Resynchronisation trials during 4th November incident 2006 (extract): Simulation and Measurement [5]

Generally the resynchronisation of larger partial networks has to be done cautiously. Unsuccessful resynchronisation attempts caused by excessive large frequency deviations have to be avoided as they stress adjacent grids and power plants and can lead to the further loss of power plants (e.g. due to shaft oscillations, voltage problems etc.). In addition, large power oscillations with amplitudes dependent on the frequency deviation of the networks being resynchronised can occur on reconnected lines and can result in the outage of further heavily loaded lines in the surrounding area.

Simulation models also allow the investigation of conditions that were not experienced in reality, e.g. resynchronisation with higher frequency deviations, line impedances or power infeeds in the partial networks. With these parameter variations it can be shown that the resynchronisation process is extremely sensitive and that under unfavourable conditions the initially isolated but stable systems can lose synchronism again.

8.3 Islanding action of the Romanian power system

The power system in Romania is relatively unusual in having systems installed to carry out automatic islanding. (The system in France – described in a further case study below – is another).

Various coordinated, hierarchical automatic measures (SPS + protections) have been established in Romania in order to isolate the Romanian power system (figure 8.1) from the neighbouring networks in case of severe events such as power oscillations exceeding a certain magnitude or the system frequency dropping below 48.7Hz. The islanding is put into effect by tie-line tripping/automatic disconnections. Underpinning the whole approach is the belief that “to keep the power system in service even under islanding operation” is a feasible idea, especially when the splitting and islands can be predicted and designed.

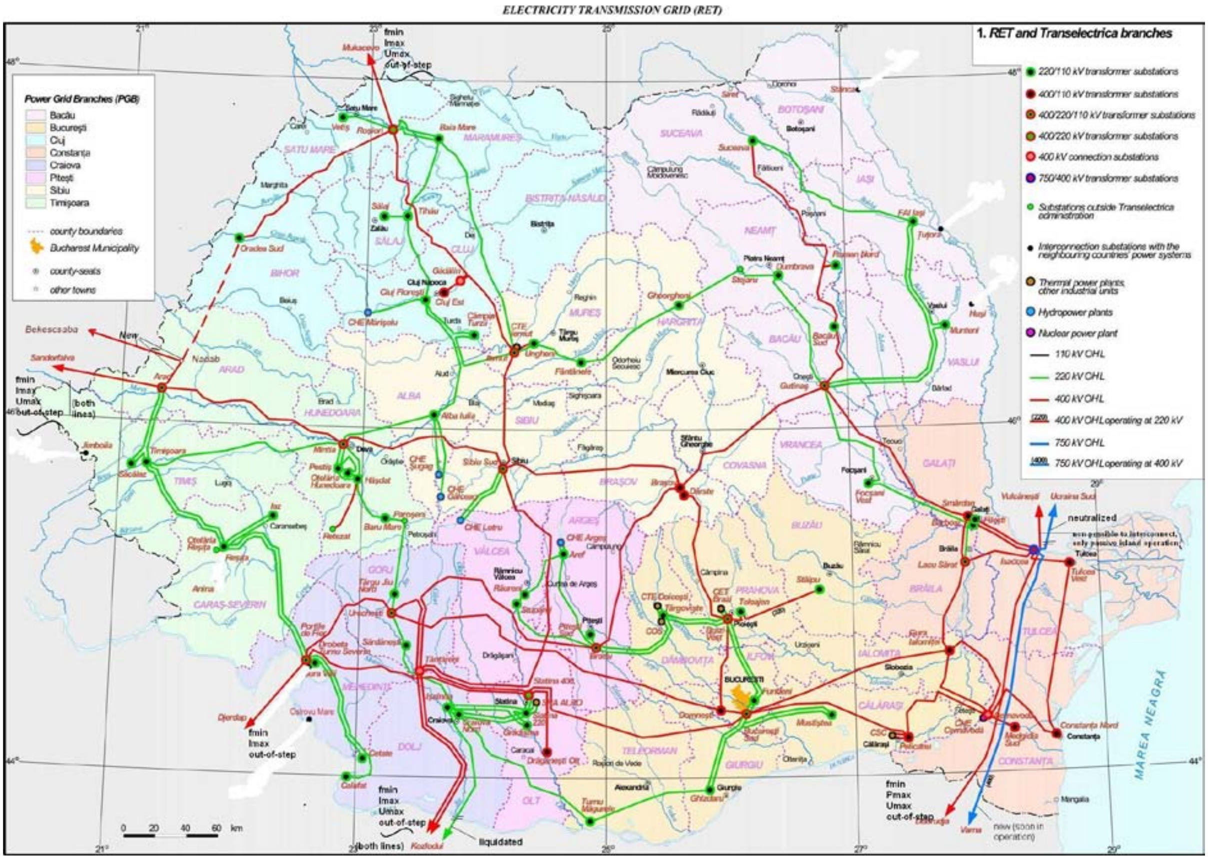

Figure 8.1: The Romanian transmission system

It is the intention that interconnected operation will prevail for as long as possible. However, when the development of an event tends to a very hard situation with a high risk level, power system islanding is judged to be an effective means of:

- avoiding propagation of a disturbance between neighbouring utilities;

- avoiding system collapse and enabling measures undertaken within Romania to be more effective;
- preventing spread of disturbances into neighbouring networks or interconnections in order that each might provide a safe source of power/voltage for restoration of the other.

The foresight of network splitting points for overloads, frequency drop or loss of synchronism is a common action agreed with interconnection neighbours.

Hereby, using a combination of SPS and protection, it is possible to cover a large range of events, as follows:

1. voltage collapse;
2. high and/or fast frequency deviations (over or under frequency);
3. cascade of the transmission lines tripping;
4. loss of synchronous operation;
5. voltage oscillations;
6. over voltage level by checking active and reactive power;
7. power swings (power oscillations).

Voltage criteria are not widely used for islanding design, only on a few tie-lines; thereby the islanding design is always based on criteria 2, 3, 4 and 6 in the above list. (Of course, criterion 2 is only about under frequency).

For the under-frequency criterion, there are conventional SPS: automatic hydro-generator start-up, automatic generator disconnection, automatic hydro-power units' regime changing (from reactive power compensator to generator), automatic load-shedding, power units' isolation on their auxiliaries, and thermal-units islanding with local consumption. Some of these SPS are based on frequency gradient ($\Delta f/\Delta t$) in addition to frequency magnitude.

If all these actions are not sufficient and the frequency drop gets under critical frequency threshold, the tie-line disconnection follows. (In the UCTE interconnection, the critical value for under-frequency is 48.7 Hz). After the tie-line disconnections, all the following measures are conceived for islanding operation of the power system. For example, the first load shedding stages (I and II) are set up over 48.7 Hz (interconnected operation) with the whole UCTE power system having frequency gradient control. The next three stages (III, IV and V) are set-up under 48.7 Hz. The islanding actions arise after automatic hydro-generator start-up and automatic hydro-power units' regime changing but before automatic generator disconnection, before units' isolation on their auxiliaries and thermal-unit islanding with local consumption. (Depending on the location and type, coordination is made both with frequency thresholds and with time-delays). The reason is to consider that if such trippings occurred, the risk of black-out is very high and it is very important to keep the interconnection in operation and to sacrifice (if there is any chance to survive) only the power system/area being faced with severe problems and dramatic development of the event.

The overall sequence of responses is summarised in Table 8.2 below.

According to the disturbance's character and complexity, the islanding can be based on one or more additional criteria:

- overload control – mainly by over-current protection (conventional protection of the line), but also active power relays (based on P_{max}) and active current component relays ($[I\cos\varphi]_{max}$) – in order to avoid the voltage cascade tripping;
- oscillation monitoring (power or voltage): by $\Delta Z/\Delta t$ and $V\cos\varphi$ methods (implemented mainly in line distance relays but also in pole slip protections/SPS) or by direct oscillation cycles counting;
- undamped oscillations followed by the loss of synchronism/asynchronous operation/out-of-step conditions – by two kind of protection/SPS: (1) pole slip protection based on $\Delta Z/\Delta t$ or $\Delta R/\Delta t$

measurement and asynchronous operation mode detection by ECO (electrical centre of oscillation) identification (on the tie-line); (2) phase current oscillations detection (only) with asynchronous cycles counting without ECO identification.

Table 8.2: automatic tripping actions on the Romanian power system

Threshold [Hz]	Time-delay [sec]	Tripping
54.00	5’’	Nuclear units
51.50	1’’	one hydro-unit in the biggest hydro-power plant (automatic disconnection)
51.00	5’’	Nuclear units - isolation on their auxiliaries (nuclear power of the reactor at the minimum limit)
50.50	2’’ ÷ 6’’	Hydro-generators - isolation on their auxiliaries
49.95/50.00/50.05	rated value for frequency = set values	
49.40	1’’	automatic hydro-generators start-up & automatic hydro-power units’ regime changing (from reactive power compensator to generator)
49.00	1’’ + Δf/Δt control	load shedding – stage I
48.80	1’’ + Δf/Δt control	load shedding – stage II
48.70	0.3’’ ÷ 0.5’’	tie-lines’ disconnection (from this point down, if all the tie-lines were disconnected, islanding operation would result)
48.60	0.5’’	load shedding – stage III
48.40	0.5’’	load shedding – stage IV
48.20	0.5’’	load shedding – stage V
48.00	5’’	Nuclear units - isolation on their auxiliaries (nuclear power of the reactor at the minimum limit)
47.50	5’’	Nuclear units
47.00	2’’	Big thermal units - isolation on their auxiliaries

If the electrical centre of oscillation is (1) within the tie-line length/impedance or (2) if the number of asynchronous periods is higher than a setting/threshold, the trip of the tie-line follows.

The power swing protections and the voltage oscillation protections without ECO identification are back-up for out-of-step protection when both are fitted. (The pole slip protections with ECO identification are not fitted on the very short tie-lines).

Disconnection of subsystems at points closest to the electrical center of oscillation is argued to be the best way to prevent forward collapse of a complete system/interconnection. Development of modern technologies suggest the possibility of future integration of the out-of-step protection into line protection terminals.

Islanding based only on frequency criteria ensures the system islanding or new islands’ repartition in a interconnection in order to restore the balance between load and generation, but the protections and SPS based on several criteria cover a large range of events and physical phenomena which can lead to the system’s collapse (not only the frequency drop). The next problem is the simultaneity of the trippings. This problem leads to the need for time coordination, namely trip time-delay coordination and tripping sequence (logical order). In theory, a well-designed sequence of trippings leads to islanding only when necessary, e.g. in the event of very fast and dramatic development of the event/phenomenon.

This coordinated and hierarchical set of automatic measures is always a reference in power system management in Romania and is an important criterion for the operational agreement with neighbours.
All the settings and limits/thresholds rated by islanding protections and SPS are benchmarks and are clearly identified in:

- operational planning, i.e. half-yearly studies including regime/load-flow computations, steady state and transient stability computations or virtual simulation for the loss of synchronous operation (e.g. the threshold power-flow on the tie-lines is pre-established from small-signal stability analysis). Following the studies' conclusions, it is possible to confirm the agreements with neighbouring power systems.
- Net Transfer Capability (NTC) assignation (monthly);
- operational programming (weekly, day-ahead), i.e. regime/power flow computations (based on *N*-1 criterion) observing all these limits and thresholds and in compliance with neighbours agreements;
- real-time operations (dispatching), i.e. the operators know the coordinated automatic plan of islanding and its key thresholds and manage the operations and controls in order to avoid breach of these limits. For example, tie-lines overload tracking is performed in order to have a reserve in case of tripping occurrence or to avoid cascade tripping. In ordinary conditions, the programming is deterministic and, as in any control centre, the "time-ahead" monitoring, right understanding and interpretation of the operational state and evolution, measures and actions are very important. The islanding automatic and coordinated plan is presented in the periodic training sessions of operators and, as far as possible, is implemented in the dispatch training simulator (DTS).

The approach described to the control and facilitation of islanding/splitting is highly complex but operated successfully on a number of occasions prior to 1989 and prevented system blackout. (During the 1980s, the system often operated between 46.8 and 49Hz and load shedding was carried out on a quite regular basis). While major disturbances have been much rarer since then and a complete and comprehensive control is not possible, it is strongly believed in Romania that such measures are justified. Nonetheless, to be effective on a larger interconnection, common rules, joint actions and coordinated works are necessary.

The design of areas where the balance of load and generation can come into effect after islanding can be based on persistent/iterative and comprehensive regime computation (*N*-1 and *N*-k criteria) for the whole interconnection or for extended parts of it. Every TSO knows very well the weaknesses in their own network (not only tie-line) and might offer all data and information for computation of the entire wider network, focusing on these points. A common agreement regarding splitting criteria is a must (frequency, voltage, $\Delta f/\Delta t$, $\Delta V/\Delta t$, oscillations/swings, overload, load-shedding, out-of-step operation and others possible). Such an approach can

- reveal regimes close to the operational limits;
- show up swinging zones or regimes leading to asynchronous operation;
- suggest which are the lines where ECO identification (in case of oscillations) is necessary (between neighbouring areas with a large surplus of generation, close to very big power units etc.);
- show up places where voltage collapse is more probable (big consumption areas, corridors with high power transfers, networks having large unidirectional power flows etc.).

Of course, this approach requires comprehensive studies (most of all, stability studies) under different operating conditions and a very good cooperation of experts from different utilities and from different countries/TSOs in the interconnection. New complex SPS based on several combinations of criteria and integrated in a logical program (software) can be a future solution.

8.4 Defence and restoration of the Turkish power system

The connection of the Turkish power system with the former UCPTE (presently, UCTE) power system has been on the agenda of Turkey since the 1970s. It is now being progressed but on the proviso that certain facilities are put in place regarding the defence of the system in Turkey and, in particular, the wider UCTE system. These facilities are the subject of this section.

The interconnection of the Turkish power system with UCTE has to provide favourable technical conditions for electricity exchange between Turkey and the other European countries. The parallel operation of the Turkish power system with UCTE will be performed at a high level of security in accordance with the UCTE Operational Handbook requirements. The disturbances in the Turkish power system should not have a cascading effect on the neighbouring power systems and the entire UCTE interconnection.

Following the conclusion of the “Complementary Studies for the Synchronization of the Turkish Power System with UCTE System” (1st UCTE Project) in order to achieve the main goal described above, an Emergency Control System (ECS) needs to be designed and installed on the interface of the Turkish power system with UCTE.

Pursuant to the UCTE Operational Handbook, it is obligatory for the Turkish power system as a candidate for UCTE membership to have a well-developed Restoration Plan, allowing prompt restoration of the Power System after blackouts, brownouts or other severe disturbances.

Only the contingencies which may occur in the Turkish power system and which could adversely affect the operation of the UCTE system, in particular the Balkan countries’ systems, are considered. As the first step, dynamic simulations were carried out of the most frequent 1st order contingencies, in particular faults on single-circuit 380kV lines internal to the Turkish grid.

In case of major disturbances in Turkey, in particular large sudden loss of generation, or large loss of load (the latter might be caused by the islanding of a regional network importing a large amount of power from the national system) the targets are as follows:

i) Maintain as far as possible the synchronous operation with UCTE
ii) At same time, limit the changes of power flows in the systems of Balkan countries and in the main UCTE system within acceptable levels, in particular within the short term power transfer capacities of the involved networks.
iii) Avoid angular and voltage instability and system separation inside Turkey, and limit, if necessary, the load shedding or generation dropping by remote control in Turkey to the minimum amount required for complying with items i) and ii) above.
iv) Eliminate (or reduce to agreed upon values) the power exchange deviation with Bulgaria and Greece

As a further step the required System Protection Scheme at the interface of Turkish power system with the UCTE system has been studied with more accurate data in the scope of the 2nd UCTE Project and will be approved by the UCTE “Interconnection of Turkey” Project Group to manage extreme contingencies.

For the purposes of providing an appropriate expediency, the Emergency Control System will be structured at three levels as described in the following subsections.

8.4.1 First Level: Special Protection System (SPS)

The SPS must prevent separation of the Turkish power system from UCTE in case of disturbances in the Turkish power system.

The SPSs are fast acting automatic systems meant to operate in case of rare, however foreseeable events which may affect the integrity of the transmission grid. Their function is quite distinct from the usual protection scheme that isolates an individual system component from the network in case of fault.

The SPSs can be defined as “event-based” systems, i.e. pre-arranged controls, designed to counter pre-defined events, or as “response-based” actions strategically located to react in response of a large range of disturbances. The Turkish TSO TEIAS proposed a SPS of response-based type, locally implemented, which is reported to be very simple, fast and secure.

A preference is given to locally implemented SPSs, based on measurements of various electrical quantities in Hamitabat TPP and Babaeski 400kV border substations and on a fast on-line elaboration by a Programmable Logic Controller (PLC), mainly intended to activate, when needed, tele-load shedding or tele-generation disconnection in Trace region via fibre optic (OPGW) channels, aimed at avoiding separation of the Turkish power system from the rest of the UCTE system, as well as avoiding unacceptable overloading or voltage deviations in the neighbouring power systems.

The reasons for giving a preference to locally implemented SPSs rather than applying a Wide Area Protection Scheme (WAPS) in the 1st stage have been mentioned in the TEIAS Defense Plans. Some WAPSs based on phasor measurement units (PMUs) that are fostered by equipment manufacturers and seem promising for the future, are reported to be under study, in particular in the Western States of North America, but not in operation yet. One exception is a WAPS designed and tested in France by the end of the 90s, however decommissioned in 2002 because of risk of line tripping and very high operating and maintenance costs (especially for the communication system, where reliability is of essential importance).

As for the additional dynamic system analyses that are to be performed for validation of the operational functions of the proposed SPS and its settings, the following should be included:

1. Detailed dynamic modelling of the Turkish, Bulgarian and Greek power systems and a simplified dynamic model of the rest UCTE system for the purposes of transient stability analyses, in time domain, with detailed simulation of large synchronous generators, excitation systems including AVRs and PSSs, turbines and turbine governors, loads, protection relays of interconnection and adjacent 400kV lines, and voltage controlled automatic switching of 400kV shunt reactors where applicable.

2. Definition of minimum and maximum load forecasts and generation dispatches to cover the most significant operating conditions after the connection of Turkey with the UCTE System. Reasonable, approximate assumptions are important for Turkey and the Balkan countries.

3. Import and export of 600MW and 1200MW to/from the Turkish power system, in addition to the zero power exchange scenario.

4. Simulation of the performance of response-based SPS under various extreme contingencies for the most important pre-disturbance operating conditions considered above. The system will be considered to be in N-1 secure prior to a disturbance. The contingencies may include but not limited to the following:
   - Sudden generation loss of 800MW, 1200MW and 2400MW in important power plants in Turkey, following a 400 kV 3-phase busbar short circuit, cleared by the busbar differential protection (including the exceptional case of stuck bus-tie circuit breaker with intervention of breaker failure protection and simultaneous loss of both busbars, causing a 2400MW generation loss).
   - Sudden loss of load of 1200MW and 2400MW due to islanding of a power importing regional network in 2 or 3 significant regions of Turkey.
   - 3-Phase short circuits in the 400kV interconnection lines and on a few critical adjacent lines, cleared by permanent opening of a faulty line during large power

export from Turkey or import to Turkey, by considering also cases with 1 of the 3 interconnection lines or 1 of the adjacent lines out of operation prior to disturbances.
- Sudden loss of large generation due to severe line/busbar short circuits in neighbouring power systems (Bulgarian and Greek, in particular).

5. Coordination of the settings and actions of the SPS with the settings and actions of the Overload Protections on the interconnection lines.

8.4.2 Second Level: Overload Protection

The Overload Protection will act as a back-up of the SPS in the cases where, for whatever, it is not effective. This is why the Overload Protection should be as simple as possible, locally based with direct measurement of the electrical variables and direct actions to the tie-line circuit breakers. Similar Overload Protections are already installed and put in operation at the interconnection lines in the South-East European power systems. Their settings are subject of a regional level coordination.

The overload protection will measure the active power flow along the interconnection lines of the Turkish power system with the Bulgarian and Greek power systems or the angle between the vectors of the voltages at the interconnection lines' ends and will disconnect the interconnection lines in case of overloads in order to prevent any asynchronous operation of the Turkish power system against UCTE.

The appropriate location of the Overload Protections is the border substations of the Bulgarian and Greek power systems on the interface with Turkish power system.

The structure, functions and settings of the Overload Protection will be defined on a basis of a specific load flow, static and dynamic studies. Calculations will be provided on a dynamic network model where the Turkish, Bulgarian and Greek power systems will be represented in detail, including the detailed simulation of large synchronous generators, excitation systems including AVRs and PSSs, turbines and turbine governors. The rest of the UCTE network will be simulated by an appropriate equivalent.

The active power thresholds will be defined on the basis of the physical network transmission capacity defined by the static calculations taking into account the thermal limits of the network equipment and voltage security criteria. The network topology scenarios will be defined in accordance with the N – 1 security criteria.

The time delay of the active power thresholds will be defined on the basis of the dynamic calculations and they will be within the range of seconds.

The settings and actions of the Overload Protections on the interface of the Turkish power system must be coordinated with the existing Overload Protections on the other interconnection lines in the South-East European region.

8.4.3 Third level: Out-of-Step Protection

In order to avoid an unintended disconnection of the interconnection lines on the interface to UCTE, the swing blocking of the distance protections should be activated. Then, an Out-of-step protection (OSP) has to be installed in order to prevent an asynchronous operation of the Turkish power system against the UCTE.

The OSP will act as a back-up of the SPS and Overload Protection in the cases when they are not effective due to any reasons.

Each interconnection line between the Turkish power system and power systems of Bulgaria and Greece will be equipped with out-of-step protection, which will disconnect the lines in case of asynchronous operation between the Turkish power system and UCTE.

The settings of the OSP will be defined on the basis of the dynamic calculations using the dynamic model already described above. The Electrical Power Swing Centre will be calculated and appropriate locations of the OSPs will be defined.

In order to avoid significant damages in the concerned power systems, the OSP has to separate them in the first cycle of the asynchronous operation.

8.4.4 Restoration Plan

General Concepts

The restoration strategy of the Turkish Power System following a total or partial blackout is in keeping with the most applied international restoration methods of large power systems. TEIAS's Restoration Plan has been tailored to the specific features of the Turkish generation and transmission systems, and has been periodically up-dated to cover the system expansions.

The Turkish power system restoration plan is designed against the following background:

i) As the end of 2007, the installed capacity of the hydroelectric power plants (HPPs) is 13,394MW, i.e. about 33% of total installed capacity (40,777MW). Almost all the HPPs have black-start capability.

ii) The East to West transmission grid of Turkey spans across a geographical distance of 1500km and consists of 14,000km of 400kV and 31,000km of 154kV transmission lines. Many of the 400kV lines are very long. A concern during restoration is line charging power. However the availability of many switchable shunt reactors (in total 3,800MVAR) and the underexcited capacity of the hydroelectric generators allow absorption of charging power and containment of power frequency overvoltages. In normal operation, the 154kV networks are operated as many regional islands, each supplied by a few 400/154kV autotransformers and a few small or medium sized generators connected to the 154kV substations.

   The 154kV lines are therefore used during restoration for the fast supply of the auxiliary services of some relatively distant shut-down thermoelectric power plants (TPPs) from small black-start hydroelectric units or gas turbines.

iii) The power plants with black-start capability are almost all the HPPs, supplemented by a number of small gas turbines (GTs) of autoproducers and IPPs.

   Most of the large natural gas combined cycle thermoelectric power plants (CCGTs), the installed capacity of which is about 10,000MW, are generally not provided with the by-pass of GT exhaust gas to the stack and do not possess the self-starting capacity.

   The vast majority of the coal fired thermoelectric units have drum type boilers. Those which do not succeed to remain in service on in-house load, and are shut-down in case of load rejection, can usually undergo a successful fast hot restart if the network is restored at their terminals within about 15 minutes. This is therefore a main target of operators during restoration.

In case of frequency deviation, generation units shall remain connected and deliver power to the transmission network for at least the minimum durations listed in Table 8.3.

Table 8.3: Minimum Duration for Power Plants in various frequency deviations

Frequency range	Min duration
50.5 Hz to 51.5 Hz	1 hour
49 Hz to 50.5 Hz	Permanent
48.5 Hz to 49 Hz	1 hour
48 Hz to 48.5 Hz	20 min
47.5 Hz to 48 Hz	10 min

All the 380kV substations are continuously manned around the clock by two operators. An operator is also continuously on duty in all the 154kV substations. So in Turkey due to that reason a faster and more reliable system restoration could be applied than the power systems where substations and HPPs are remotely controlled by a small number of Control Centres.

iv) Owing to the large geographical size of the Turkish system and to the presence of black-start power stations in most of the regions, the restoration following a national or multiregional blackout is to be performed "in parallel" in various subsystems, to be as soon as possible synchronized to each other for re-instating the national interconnected system.
Criteria for sectionalizing of subsystems are the following:

a) Each subsystem must have a black-start capability which is sufficient to restore power to shut-down TPPs and to some priority loads.

b) Each subsystem must have the ability to match generation and load to within prescribed frequency limits until synchronisation is performed with the neighbouring subsystem(s).

c) Each subsystem should have adequate voltage control capacity to maintain a suitable voltage profile. This would include the ability to pick-up loads, to under-excite generating units, to change taps on the autotransformers and step-down transformers and to make optimal use of shunt reactors and shunt capacitor banks.

d) Each subsystem should be sufficiently monitored by a System Control Centre in order to ensure its internal security and to coordinate switching. All 380 kV and some important 154 kV substations of control centres which do not have SCADA system at the moment, are being monitored by neighbouring Regional Control Centres (RCCs) and the National Control Centre (NCC).

The subsystems supervised in Turkey by the RCCs of the national SCADA system in general comply with the above requirements. At present the RCCs connected to the SCADA system are six, but three more will be commissioned in near future. The coordination provided by each RCC under the guidance of the NCC therefore makes the subsystems supervised by RCCs as the suitable subsystems for the "in parallel" restoration, with minor territorial departures where appropriate.

Experience in Turkey has shown that the achieved frequency and voltage controls during restoration minimize the risk that generating units are shut-down by their protection relays after re-start, and also minimize the risk that picked-up loads are disconnected by the underfrequency load shedding relays in the distribution networks.

Periodic checks are performed to ensure that the black-start generating units are capable of quickly performing their functions in case of need.

The load amounts which are shed rotationally by low-frequency relay are given in Table 8.4.

Table 8.4: low-frequency relay settings in Turkey

Time Period	1st step (49,00 Hz)	2nd step (48,80 Hz)	3rd step (48,60 Hz)	4th step (48,40 Hz)
Minimum Time	850 MW	1200 MW	1100 MW	2000 MW
Day Time	1700 MW	2500 MW	2350 MW	3500 MW
Peak Time	1900 MW	3000 MW	3000 MW	4200 MW

SCADA and Telecommunication System

The DC stored energy and AC diesel generators in the power plants, in the NCC and RCCs, as well as the DC stored energy in the substations, are designed to ensure operation of the telecommunications and SCADA system during restoration time, with large margins (minimum 10 hours) . This includes the 48 V dc system for telecommunication and SCADA facilities as well as 110 V dc system for protection relays in 154kV and 380kV substations.

TEIAS has its own telecommunication system (PAX) using power line carriers and fibre optic links belonging to TEIAS. The Turkish Telecom System is also available for use. The telecommunication lines between RCCs and the NCC are duplicated (on satellite and fibre optics) and ICCP communication protocol is used between them. Spare lines are hired fibre optic lines belonging to Turkish Telecom. In particular, reliable telephone communications are ensured between Control Centers and all the HV substations, including all 154kV substations at present not included in the SCADA system.

The computers in the SCADA system are all redundant and in case of a complete SCADA system failure in the NCC located in Golbasi, all the functions of the system can be executed via the Emergency National Control Centre located in the TEIAS General Management Building.

Training and Tests

Periodic training of operators (once a year) and tests are performed on system restoration procedures. Standing instructions are provided to the operators of all levels, for their orderly actions in case of blackout. These concern autonomous as well as coordinated actions with the RCCs and NCC.

The Dispatcher Training Simulator of the SCADA system in the NCC and RCCs is also used for restoration training of the operators and engineers in control centres.

The test for black start capability of the power plants is performed individually in the power plants in two years period (National Grid Code).

Philosophy of the Restoration Plan

The restoration plan is prepared to be started by dividing the system into 9 isolated islands corresponding to the 9 RCCs. Since power plants with black start capability are distributed all over the system, the procedure is started simultaneously in each island with completion of the whole ring under the coordination of NCC in a case of a complete black out. Also, the import of energy from Bulgaria and the start of a recovery from the Trace region and synchronisation with the Northwest Anatolia RCC is explained under a separate section of the plan.

The restoration plan for each island and interconnection with neighbouring islands under the coordination of the NCC is defined separately with appropriate maps.

To avoid frequency instability during load restoration, enough primary and secondary reserves should be supplied from the Power Plants which will be in service at the first step of the process.

For re-synchronizing isolated systems synchro-check devices are used at substations listed in the plan. Because all substations are manned, manual synchro-check devices are located for all others which are not in the list. The criteria of the operation are max 30 degree phase angle and 10% voltage difference. To obtain these values, reactors and reactive productions of the generation units are used (under-exciting the unit). Decreasing the demand or increasing the generation in the low voltage side is another way used for synchronizing.

Operator Instructions to Manage the Power System Restoration

The main responsibility and management of the restoration process after a total blackout belongs to the NCC located at Golbasi/ANKARA

In case of a total blackout of the system, all the managers and engineers in control centres are called on duty. A large number of staff in control centres including the managers and deputy managers are living in utility houses very near to the control centres from which it takes 5 minutes to reach to the control centre. All the group departments responsible for operation and maintenance of the substations are on standby in case of a failure of the equipments.

RCCs restore their 154 kV system separately in island mode and execute frequency and voltage control. After the 380 kV ring between regional islands is completed under the coordination of the NCC, frequency control is taken over by NCC.

In case of a regional blackout, the manager and the engineers of the related centre and the Manager of NCC are informed to be on duty. The manager and the engineers of the group departments responsible for operation and maintenance of the related region are informed by the operators in the substations. The 380 kV lines are put into service in coordination with the NCC and the 154 kV lines are put into service in coordination of the related RCC.

The restoration plan is prepared by NCC in coordination with RCCs and approved by Board of Directors of TEIAS. The plan is updated every 2 years. Commissioning of new system facilities or de-commissioning/outages of system components or change in the system conditions also require inspection/update of restoration plan.

Expected Restoration duration Example From The Past

As an example of execution of the restoration plan and how quickly a restoration can be achieved, Table 8.5 gives the case of a Blackout Affecting 100 % of the Entire System after the Marmara (moment magnitude=7.4) earthquake in 1999.

Table 8.5: extent of historic blackouts in Turkey

Date	Amount of the Blackout (MW)	Region	Restoration Time
17-08-1999	16000 MW	Whole Country	5 Hours

8.5 The Auckland 'diversity' investment

This Brochure has not been concerned with investment planning for the provision of additional conventional system capacity such as by new overhead lines, underground cables and substations. However, one of the main subjects of CIGRE WG C1.17 has been the impact of liberalisation on transmission system planning and, in particular, the justification of investments motivated by the management – whether prevention or containment – of major unreliability events.

The case study described in this section concerns a transmission investment proposal brought forward by Transpower in New Zealand, initially to provide additional system capacity into Auckland but finally justified to the New Zealand regulator, the Electricity Commission, on a basis of containment of the impact of a low probability event.

8.5.1 Time line

In September 2005, Transpower submitted a proposal for a new 190km 400kV double circuit, 9km of underground cable and associated substation works in order to increase the transmission supply capacity into the Auckland area in the North Island. A large part of the motivation was the increasing demand in and around Auckland and the need of generation, mostly in the south, to gain access to that demand. The estimated cost in 2005 was NZ$770m and commissioning was intended by May 2010 [6].

Transmission investments in New Zealand at time of writing are subject to a 'Grid Investment Test', or GIT. This intends that the economic benefit of a proposal must be clearly demonstrated in respect both of the total cost of electricity and the value of unsupplied energy. The Electricity Commission engaged consultants to review Transpower's proposals and, in April 2006, published a draft conclusion that the proposal failed to meet the GIT and was therefore not approved [7].

On June 12, 2006, a major fault occurred involving two 220kV transmission lines and three sections of 110kV busbar at Otahuhu substation. It was the result of the mechanical failure in high winds of, initially, a single earth wire and, soon after, another earth wire, both on 220kV circuits that overflew the 110kV substation at Otahuhu and caused the tripping of a number of circuits out of Otahuhu that in turn led to loss of supply to around half the Auckland load, including all of the central business district, for several hours.

In October 2006, Transpower submitted an amended proposal for reinforcement of transmission capacity into Auckland. The amended proposal still included 190km of double circuit overhead constructed with the capability of operating at 400kV and some km of underground cable, but it was proposed initially to operate the new double circuit only at 220kV. A new 220kV substation, upgrading of some 220kV overhead line, 350MVAr of reactive compensation and the operation of an existing 110kV line at 220kV were also part of the proposal with the cost quoted in [8] being NZ$824m (including NZ$210m of 'contingency'). Commissioning was intended for 2011. The amended proposal also included arguments based on strong alignment with the draft GPS (Government Policy Statement), "particularly with respect to an emphasis on renewable generation, provision of diversity of supply to Auckland and minimisation of the number of corridors required for transmission." [8]

8.5.2 Investment approval

One of the reasons cited in the Electricity Commission's April 2006 rejection of the original investment proposal had been a lack of confidence that the additional capacity into Auckland would really be needed, it being possible that one or more new generation projects would be developed in the interim that would help to meet Auckland load and reduce the import need. Once applied in a probabilistic assessment (using, it is assumed, probabilities of different generation scenarios occurring determined by the Electricity Commission), the average benefit of the original proposal came out less than what, in the context of the main investment, amounted to a 'do nothing' alternative.

In the submission of the amended proposal, Transpower cited a 'deterministic' criterion "that, in Transpower's view, is consistent with the Grid Reliability Standards in that it makes the 'reasonable' allowance that the largest generator in the Auckland area may not be available at the same time peak demand occurs" [8]. Furthermore, it noted that, following the June 12 event, "a review of the Auckland supplies indicated a lack of diversity in relation to:

- Substation switchyards;
- Substation locations; and
- Transmission line corridors." [8]

It also noted that "the draft [Grid Policy Statement] has an objective to provide adequate alternative supply routes to larger load centres and to be resilient against low probability but high impact events" [8].

In January 2007, the Electricity Commission published notice of its intention to approve the amended proposal and in July 2007 it published its final decision to approve it [9].

In its response to the amended proposal, the Electricity Commission made no reference to probabilistic investment criteria. (It did, however, note that 'judgement' would inevitably be required in the appraisal of any investment proposal) [10]. Under each alternative investment option identified by Transpower in its submission to the Electricity Commission in support of its revised investment proposal, Transpower quoted an estimate of the unsupplied energy that would be consequential to loss of each of the main substations supplying power to Auckland; the option that was finally approved had the lowest unsupplied due to such a low probability event. However, neither in Transpower's submission nor the Electricity Commission's published response were numeric probabilities of these events compared or, seemingly, used in the investment appraisal. Notwithstanding the public dissent of one commissioner [11], it would appear to have been sufficient to have noted the credibility of such an event and the extent of its impact.

It is left to the reader to draw his or her own conclusions regarding the consistency of the Electricity Commission's position in April 2006 with that in October 2006 and to what extent the major unreliability event of June 12 influenced any change. However, based on the evidence of what was published both by Transpower and the Electricity Commission, it can be safely concluded that the intention to contain the impact of a low probability single event (the loss of a substation) and to ensure diversity of supply routes was a key part of the design of the revised investment proposal that was finally accepted by the Electricity Commission.

8.6 Under Frequency Load Shedding in England and Wales

The electricity supply industry in England and Wales was one of the first in the world to be liberalised with separation of ownership of generation and transmission, encouragement of competition in generation and retail and the encouragement of investment funded by private capital. In such a structure, the role of the regulator and the responsibilities it places on the system operator is key. This case study concerns a response made by the system operator in England and Wales to what it perceived to be a key issue, that of containment of major unreliability events, and the steps it took to update one of the facilities contributing to it.

8.6.1 Origin of under frequency load shedding in England and Wales

Prior to privatisation in 1990, the state-owned electricity system in England and Wales was governed separately from the state-owned system in Scotland, though both these systems are synchronously linked. Thus, the under-frequency load shedding (UFLS) scheme in England and Wales was different from that of Scotland, and this difference has continued through to the present day.

The scheme originated in the late1960s, with about 1500 relays mostly installed at 33kV and 4 frequency stages at 10% each, with relays uniformly distributed across the network. However, leading up to 1985 the following observations were made:

- Increased power flows on the system increased the risk of occurrence of a generation deficit of more than 40%.
- The old relays were obsolete; new relays would enable the first 3 stages to operate faster and thus enable load shedding to prevent frequency falling below 47.0 Hz.
- This improvement would reduce the risk of a total system shutdown and facilitate the faster restoration of power.

In 1985, the following improvements implemented:

- Load shedding increased from 40% to 60%.
- The number of stages increased from 4 to 9 with the installation of an additional 450 modern, faster relays which were used for the first 3 stages. Maximum operating time of these relays was 200 ms.
- Some re-scheduling of stages, and removal of some time delays.

Though the scheme had a financial benefit, based on a ‘value of lost load’ (VOLL) of £2000/MWH, and a possible loss of £600M in the event of a widespread blackout, the driver for this scheme was system security and reduction of risk of a major blackout.

The revised settings from 1985 were as listed in Table 8.6.

Post privatisation, National Grid Electricity Transmission (NGET) now owns the transmission network in England and Wales but operates the transmission network in England, Wales and Scotland. The distribution network in England and Wales is owned and operated by a number of separate Distribution Network Operators (DNOs). The DNOs are the owners of the UFLS relays but NGET is responsible for the performance specification of the UFLS scheme.

Table 8.6: Under-frequency load shedding settings in England and Wales in the late 1980s

Stage	1	2	3	4	5	6	7	8	9
% Load	5.0	5.0	10.0	7.5	7.5	7.5	7.5	5.0	5.0
Frequency	48.80	48.75	48.70	48.6	48.4	48.1	47.7	47.3	47.0

8.6.2 Scheme Review 2001

With a further increase in power flows since privatisation in 1990 and the increasing amount of generation with reduced low frequency endurance, the UFLS scheme was again reviewed in 2001 by NGET, with the support of the DNOs.

The review concluded that revised frequency settings and faster operating relays were necessary in order to maintain the scheme's performance. However, the DNOs had, over the years, progressively replaced their older, slow relays in conjunction with their substation refurbishment work and in 2001 there were only about 600 of the original 1500 old relays still in service. The cost of replacing these amounted to some £5m, and the scheme was approved by the regulator (Ofgem) in 2002 on the basis of maintaining technical performance. A programme of work has been initiated by the DNOs, with all old obsolete relays expected to be replaced by 2010.

Concurrent with the replacement of older relays, a set of revised setting was specified. The latest scheme requires all relays to operate within 200 ms, with settings as in Table 8.7 [12].

Table 8.7: Revised under-frequency load shedding settings in England and Wales

Stage	1	2	3	4	5	6	7	8	9
% Load	5.0	5.0	10.0	7.5	7.5	7.5	7.5	5.0	5.0
Frequency	48.80	48.75	48.70	48.6	48.5	48.4	48.2	48.0	47.8

8.7 Defence and restoration of the French power system

This case study concerns defence of the system in France and plans put in place for its restoration. The defence measures employed in France include some that were introduced following major unreliability events in the 1980s and are not commonly used elsewhere. In addition, aspects of restoration planning are consequences of the preponderance of nuclear generation in France and are therefore highlighted in this section. For further details, consult the RTE Reliability Handbook [13].

8.7.1 Introduction to defence plans in France

In the course of a major incident, the different phenomena described in the previous chapters may occur successively or in combination. System reliability is based on the implementation of various types of measures, adapted to the dynamics of each phenomenon and which help prevent, detect and deal with any malfunctions that may lead to the emergence of the incident and/or to control its development.

These measures, which also come within the domain of equipment, organisation and quality of professional action, are referred to in France as 'defence lines'. The implementation of successive defence lines constitutes the defence in depth concept.

This principle is commonly applied in the field of nuclear safety as in the operating reliability of many complex industrial systems for which a high level of reliability is required.

The defence lines concern three main complementary fields:

- prevention / preparation;
- monitoring / action;
- ultimate mitigation measures.

8.7.2 Defence in depth applied to the feared phenomena

The defence lines are structured as follows for each of the phenomena likely to lead to System collapse.

Defence lines to counter cascade tripping

a) Prevention / preparation

First of all, it is essential to have a perfectly coordinated and sufficiently selective protection plan so that, when a short-circuit occurs, only the facilities needed to clear the fault are tripped.

As concerns the lines, the smooth operation of the reclosing function is particularly decisive because it ensures the automatic restart of the facilities after a few seconds, in the case of transient faults.

Secondly, one must be able to make use, in real time, of sufficiently “sturdy” operational diagrams to avoid the occurrence of the phenomenon. This is achieved by applying the “N-k” rule to the various stages of preparing System operation and control, in such a way as to ensure, for a number of incidents referred to as “reference likely incidents”, that the consequence level remains within a predefined threshold.

The reference likely incidents are the outage of a single line, the outage of a double line, the outage of one or two 1,300 MW units and the outage of a busbar section. The measures taken concern the operating scheme and the generation unit start-up plan.

b) Monitoring / action

What has to be done at this stage is to carry out appropriate control actions so as to remove any facility overload occurrences before they reach the end of their tripping time, by means of switching operations on the network or by action on the generation units (the overload protections generate an alarm which is sent on to the dispatching centres).

c) Ultimate mitigation measures

When transfer operations prove to be insufficient to put a stop to the present overloads, the ultimate action is to deliberately carry out load shedding of customers or generating facilities.

Defence lines to counter voltage collapse

a) Prevention / preparation

What this involves is to:

1) properly size the means of reactive energy compensation and network facilities, so as to have the necessary and adequate reserves and be able to convey them;
2) have sources of reactive power capable, whenever needed, of providing it with the expected level of performance. The measures taken concern the generation unit start-up plans from the standpoint of their reactive generation capacity, the closing of network compensation equipment (capacitors and/or reactors), and the utilisation of synchronous compensators and other devices;

3) be able to effectively call up the reactive power reserves that have thus been set up. This assumes having reliable and operational secondary and tertiary voltage control systems, as well as systems controlling effective means of compensation.

b) Monitoring / action

This mainly consists in monitoring and controlling the voltage plan under normal operating conditions.

Voltage control under normal operating conditions is achieved through a succession of three command levels with staggered time constants making it possible to mobilise the reactive reserves over increasingly extensive area:

- primary control, which brings on line the reactive reserve of the generation units closest to the disturbance, through the action of their primary voltage controller when voltage variations are observed at the stator, so as to keep this voltage equal to the displayed set point value;
- secondary voltage control, which brings on line the reactive reserves of all the generation units and capacitors by electrically homogeneous zones from the standpoint of voltage behaviour. These zones are called "secondary voltage control areas". The purpose of secondary voltage control is to keep the voltage constant at a central point of the zone known as "pilot point";
- tertiary voltage control, which is manual. It concerns all of the actions commanded by the operators of dispatching centres to coordinate the voltage plan between the different secondary control areas. These commands concern the changes of the set point voltage of pilot points, as well as switching commands to reclose or trip compensation equipment. It may also involve the start-up of generation units or the modification of network topology.

c) Ultimate mitigation measures

Their purpose is to control the evolution of the voltage plan under incident operating conditions when the voltage collapse phenomenon gets under way, through action on the loads by:

- automatically blocking the on-load tap changers of EHV/HV and HV/MV transformers as soon as the voltage reaches a critical value at certain points of the network (the voltage drop can evolve rapidly: about 10 to 20 kV/min);
- lowering the MV voltage level by 5%.

If need be, these actions give way to "drastic" measures commanded by the dispatching operators, applied to generating facilities or load:

- utilisation of reactive overloads on the generation units,
- start-up of rapid means of generation, such as combustion turbines,
- and, as a last resort, activation of emergency remote load shedding or even disconnection of EHV/HV transformers or 400/225 kV autotransformers.

Defence lines to counter frequency collapse

a) Prevention / preparation

The actions undertaken at this level are intended to make the means available to dispatching centres for control of the supply/demand balance; it involves:

- having a load forecast (load level at peak load period, shape of load curve, etc.) and a forecast of cross-border exchanges;

- having a global generation plan capable of meeting the load forecast and exchanges, with a sufficient margin to cope with the different contingencies that may affect the supply/demand balance: outage of generation units, imbalance between load forecast and actual load, etc. This is obtained by setting up power reserves made available either by automatic control devices (primary and secondary reserves), or by the action of operators (tertiary reserve);
- being able to bring these power reserves on line within the different time periods required.

b) Monitoring / action

The effective availability of the power reserves set up must be checked regularly in real time. The actions undertaken are aimed at maintaining the frequency under normal operating conditions by successively bringing the various reserves on line according to the staggered time constants.

Each reserve level makes it possible to reconstitute the reserves of the previous level. These three reserve levels are managed and reconstituted by automatic primary and secondary load frequency controls and tertiary control placed under the control of the dispatchers.

- The purpose of primary control is to ensure the rapid restoration (a few seconds) of the supply/demand balance. It is a local control, carried out by the speed controller of each generation unit subject to control, which acts directly on the valves letting motor fluid into the turbine. At the end of action, the new balance situation results in a frequency imbalance and border exchanges differing from their scheduled value.
- The aim of secondary control is to bring the frequency back to the reference frequency (50 Hz in general, 49.99 or 50.01 Hz in case of a “time adjustment”) and the cross-border exchanges back to their scheduled values. This goal is met by modifying the set point capacity of the generation units subject to secondary power frequency control by means of a signal calculated on a centralised basis at the national dispatching centre.
- Tertiary control consists in activating balancing bids to readjust the generation schedules on some sets in order to reconstitute the secondary reserve, or even part of the primary reserve when it is started, so as to provide protection against a new contingency. The corresponding actions are all under the control of control operators at the dispatching centres.

c) Ultimate mitigation measures

In situations where normal operating actions are not sufficient to keep system frequency within limits, exceptional control actions are carried out:

- on generation: switchover to Pmax,
- on loads: rapid customer load shedding, remote emergency load shedding.

If the previous defence lines are bypassed upon a contingency exceeding the primary reserve available on the interconnected network or possibly on sub-networks which may be set up in case of a major incident, the last line of defence is frequency activated load shedding. It is a load shedding operation carried out automatically, on a frequency threshold criterion, and selectively on the MV outgoing distribution feeders of main substations and on the non-priority installations of customers connected to the main transmission system.

The load shedding thresholds are set as follows: 49 Hz, 48.5 Hz, 48 Hz and 47.5 Hz. A load shedding level is associated with each threshold. For distribution, the volume of each level must correspond to 20% of the total load.

Defence lines to counter loss of synchronism

a) Prevention / preparation

The aim is to have sufficient stability margins at the operator's disposal, which implies:

- having operational and appropriately adjusted voltage and speed control systems, capable of maintaining the stability of the generation units upon event occurrences;
- having a sufficiently effective network protection plan so as not to have to use generation unit voltage and speed control devices beyond their possibilities, due to short-circuits being cleared too late. With regard to conventional thermal and nuclear generation units, the expected performance level of this protection plan must maintain stability regardless of the type of fault: single-phase or three-phase fault, with or without reclosing, on a line or busbar;
- operating the power system in such a way as to never be in a topology, either naturally or subsequent to switching operations or tripping, that is conducive to the development of the phenomenon: case of long radial transmission networks, for example. This is ensured by applying the "N-k" rule in system design and at the system operation and control preparation level. In the field of stability, this rule consists in making sure that the System remains stable upon a facility outage related to a fault correctly cleared by the protection system. The measures taken concern the measures taken concern the robustness of system exploitation schemes, limitations on the active power supplied by the generation units or a minimum level of supply of reactive power and voltage to be observed.

b) Monitoring / action

The main aim of the corrective actions undertaken is to counter the acceleration of the generation units upon a short-circuit occurrence, by releasing the motor torque applied to the rotor; this is performed by the speed controller which, during major disturbances, controls the fast closing of the turbine inlet valves, as well as by the operation of the threshold accelerometer (thermal generation units).

c) Ultimate mitigation measures

When loss of synchronism occurs between generation units, the defence principle consists in automatically splitting all or part of the network, so as to quickly separate the region or group of power regions sustaining a loss of synchronism from the main grid that is still sound.

This is achieved on the basis of local protection devices called "Ring opening in case of loss of synchronism", which detect the voltage beats and dips characterising the phenomenon. (Figure 8.2).

These devices are installed according to the regularly updated DRS[15] plan, on a number of 400 and 225 kV lines providing a power link between areas the generation units of which are highly likely to have a homogeneous dynamic behaviour in case of loss of synchronism.

As the automatic splitting action generally leads to upsetting the local balance between generation and load, automatic actions by frequency activated load shedding relays may be necessary to restore balance in the insufficient areas.

After the division, if a return to stable operating conditions can be obtained in a given area, the thermal generation units automatically trip to house load on their auxiliaries in order to be able to proceed with service resumption more rapidly.

The basic principle is not to disconnect them too soon so as to allow the System enough time to become stabilised through the action of controls, and not disconnect them too late so as not to use the

[15] DRS is the French acronym for detection of loss of synchronism. – "Détection de Rupture de Synchronisme".

facilities beyond their sizing limits; this assumes the perfect coordination of both generation unit and network protection systems.

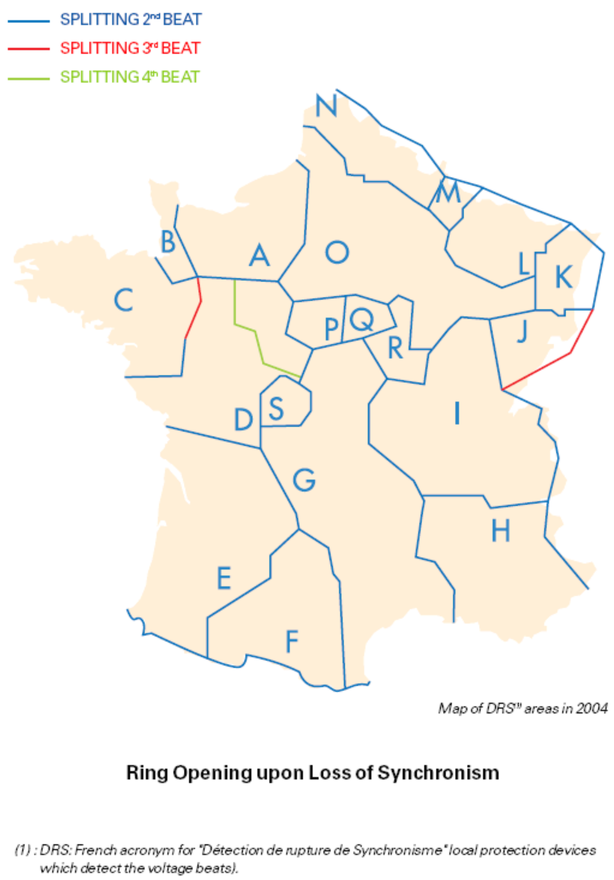

Figure 8.2: regions I France subject to automatic splitting

8.7.3 Particular network restoration issues in France

A characteristic of the power system in France is that it has a very large proportion of its generation capacity made of up nuclear power plants. This section addresses some particular considerations that arise as a consequence.

The strategy of the French system operator, RTE, is to able to restore all or part of the network after a widespread incident in the absence of any possible back-up from a powerful, still live grid (in France or abroad), To achieve this, the plan is mainly based on nuclear generation units that have tripped to house load and for nuclear units of up to 900MW to be capable of operating with loads of only around 50MW.

For power to eventually be restored to consumers, tripped thermal generation units, in particular nuclear sets, must be restored to operation and this in turn depends on the rapid restoration of power supply to their on-line auxiliaries which requires fast restoration of voltage.

The “zero voltage plan”

This question of restoration of voltage to nuclear power station auxiliaries has led to the development of a specific “zero voltage plan”.

Upon loss of voltage, automatic network splitting is carried out by specific programmable logic controllers, called "zero-voltage automatic devices". If necessary, supplementary actions are performed by the operators. All of the measures relative to the location of programmable logic controllers and the splitting into load pockets of about 50 MW form part of the "zero-voltage plan".

The System regional operating units are responsible for keeping the zero-voltage plan operational. This may involve adapting the splitting to the structural changes of the network, ensuring compatibility with voltage recovery scenarios, and verifying the correct positioning of programmable logic controllers.

Network restoration by main regional structures

Depending on the nature of the system disturbance and the network's condition when a collapse is arrested, responsibility for key aspects of restoration may be delegated to regional control centres.

The principle is based on the independent and simultaneous constitution, in each of the seven regions, of predetermined 400 kV structures called "main regional structures" (figure 7.4). These structures are designed so as to link, at each regional hub level, the nuclear units and a number of large hydro generation sites to the supply substations of the major load areas.

The feasibility of main structures is closely linked to the rate of success of the tripping of nuclear units to house load.

Voltage recovery scenarios

Nuclear generation units in France are subjected to precise rules relative to the power supply of their auxiliaries. These rules require the fast restoration of the power supply of at least one of the two external sources supplying power to the auxiliaries of a unit that has tripped in case of the outage of at least one of its internal sources.

In a widespread incident situation, RTE is therefore likely to make public transmission system components available to make it possible for nuclear units to receive voltage either from a "strong" network in France or from abroad, or if this is not possible, from another generation unit.

The "source unit - public transmission system components - target unit" combination constitutes a voltage recovery line; all of the operations for line implementation are what is known as a "voltage recovery scenario". There are several scenarios for each nuclear generation site.

A nuclear generation unit requesting that voltage recovery be implemented transmits specific remote information to the regional dispatching centre. RTE chooses the scenario that is the best adapted and quickest to implement. The source unit in the line is then called up according to RTE instructions to re-energise the recovery line followed by the powering of the auxiliaries of the requesting nuclear generation unit.

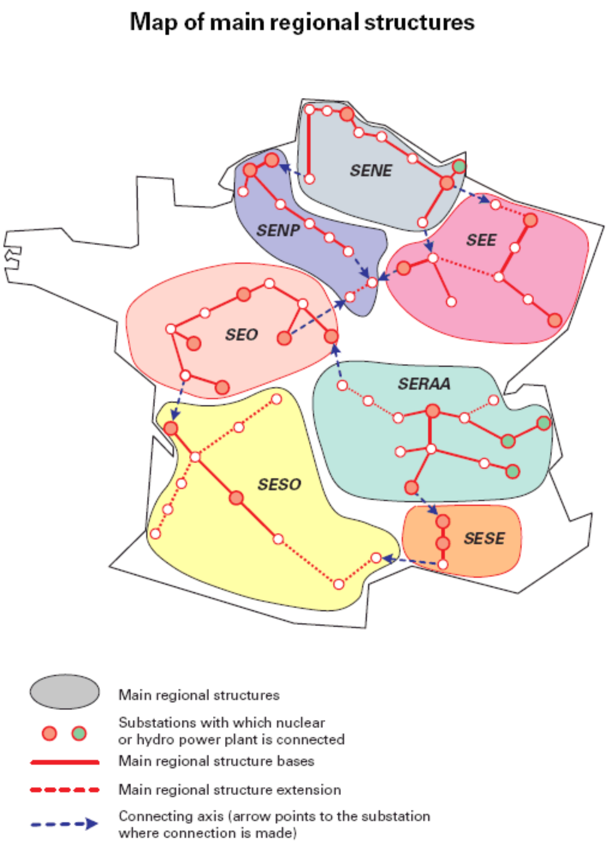

Figure 8.3: main regional structures for network restoration in France

8.8 Cyber Security – A New Security Issue?

The electricity supply industry in the United States and Canada has suffered a number of major unreliability events, some of which are summarised in Chapter 2 above. A number of the investigations have highlighted some familiar issues which have led, over time, to the introduction of new standards and procedures. However, in the last few years, the industry and regulatory authorities in North America have identified what is commonly regarded as a new threat that presents a risk of major disruption to electricity supply: 'cyber security'.

This section contains a case study concerning definitions of and responses by the power industry in North America to 'cyber security'. It goes on to highlight some issues that go beyond risk of malicious attack and are argued to be fundamental to concepts of 'critical assets'.

8.8.1 The origin of power industry concerns for 'cyber security'

Prior to the 2006 transition of the North American Electric Reliability Council (NERC) from a voluntary reliability organization to an organization that is responsible for developing and enforcing mandatory reliability standards, NERC was involved in infrastructure security. The citation below from a 2002 NERC document describes NERC's historic involvement in critical infrastructure protection. From the extract, it can be seen that NERC has had a longstanding concern with what is now commonly referred to as 'cyber security'.

> "Since the early 1980s, NERC has acted to address the electromagnetic pulse phenomenon, vulnerability of electric systems to state-sponsored, multi site sabotage and terrorism, Y2K rollover impacts, and now the rapidly evolving threat of electronic intrusion as well as

physical attack. At the heart of NERC's efforts has been a commitment to work with various federal government agencies to reduce the vulnerability of interconnected electric systems to such threats.

"The Report of the President's Commission on Critical Infrastructure Protection (PCCIP) in October 1997 led to a May 1998 Presidential Decision Directive (PDD-63). PDD-63 called for government agencies to become involved in the process of developing a National Strategy for Critical Infrastructure Assurance, and to seek voluntary participation of private industry to meet common goals for protecting the country's critical infrastructure through public-private partnerships. … In September 1998, the Secretary of Energy wrote to the NERC Chairman seeking NERC's assistance, on behalf of the Electricity Sector, in developing a program for protecting the continent's critical electricity sector infrastructure". [14]

As a result of PDD-63, NERC established the Electricity Sector – Information Sharing and Analysis Center (ES-ISAC). ES-ISAC is one of 11 industry sector ISACs that share a common purpose: "to communicate with its members, its government partners, and other ISACs about threat indications, vulnerabilities, and protective strategies. ISACs work together to better understand cross-industry dependencies and to account for them in emergency response planning."[16]

8.8.2 Concepts related to 'cyber security '

Cyber security is specifically referenced in the section of the Energy Policy Act of 2005 that created the Electric Reliability Organization, which is now NERC. The portion of the act that dealt with the ERO has this definition:

"The term 'reliable operation' means operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, *or unanticipated failure of system elements." (Emphasis added)*

Key concepts in the understanding of "cyber security" developed by NERC are summarised in Table 8.8.

On January 17, 2008, the U.S. Federal Energy Regulatory Commission issued Order 706 that approved eight NERC cyber security reliability standards, making these standards mandatory in the U.S.[17] Of that suite of standards, Standard CIP-002 noted the need for a "responsible entity" to develop a risk-based assessment methodology to use to identify its Critical Assets with specific attention drawn to the following classes of assets:

- "Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.
- Transmission substations that support the reliable operation of the Bulk Electric System.
- Generation resources that support the reliable operation of the Bulk Electric System.
- Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.
- Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.
- Special Protection Systems that support the reliable operation of the Bulk Electric System.

[16] From the ES-ISAC Web site: http://www.esisac.com/faq.htm.
[17] See NERC press release at http://www.nerc.com/news_pr.php?npr=29.

- Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment."

In respect of specifically 'cyber' assets, CIP-002 noted facilities at control centres such as automatic generation control and real-time power system modelling and characteristics such as use of "a routable protocol to communicate outside the Electronic Security Perimeter", "a routable protocol within a control center" or dial-up access.

Table 8.8: NERC definitions of terms related to 'cyber security' [15]

Term	Definition
Cyber Security Incident	Any malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or, • Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset.
Critical Cyber Assets	Cyber Assets essential to the reliable operation of Critical Assets.
Cyber Assets	Programmable electronic devices and communication networks including hardware, software, and data.
Critical Assets	Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.
Electronic Security Perimeter	The logical border surrounding a network to which Critical Cyber Assets are connected and for which access is controlled.
Physical Security Perimeter	The physical, completely enclosed ("six-wall") border surrounding computer rooms, telecommunications rooms, operations centers, and other locations in which Critical Cyber Assets are housed and for which access is controlled.

8.8.3 Issues arising in respect of 'cyber security'

Order 706 noted some of the discussion that had occurred in the electricity supply industry in North America since the 8 cyber security standards were made effective. In particular, Order 706 included a response to a query regarding the appropriateness of an "N-1" reliability criterion in the identification of critical assets.

> *"use of an N minus 1 criterion for the risk based assessment in CIP-002-1 would result in the nonsensical result that no substations or generating plants need to be protected from cyber events. … The fact that the system was developed to [be able to] withstand the loss of any single asset should not be the basis for not protecting that asset."*

The discussion seems to presuppose that the transmission system had been designed to be operable following the loss of a single generating unit or an entire single substation. It is the experience of members of CIGRE WG C1.17 that transmission systems are rarely, if ever, designed to be secure against the loss of entire substations, though there may be a requirement to avoid particular consequences in the event of, for example, loss of a single bus section or bus coupler. In addition, the use of the term "N-1" suggests that the "1" refers to a single asset rather than a single event, an approach that can lead to neglect of significant and credible operational risks. (See the discussion on meanings of security in Chapter 3 of this Brochure). However, the observation provides a useful reminder that system operation should be concerned with all risks. This message is further reinforced in Order 706:

> "A cyber attack can strike multiple assets simultaneously, and a cyber attack can cause damage to an asset for such a time period that other asset outages may occur before the damaged asset can be returned to service. … We note that the definition of 'critical assets' is focused on the criticality of the asset, not the likelihood of an outage."[18]

While discussion among the international membership of CIGRE WG C1.17 that has been responsible for the present Brochure reveals that representatives from countries outside North America believe the specific threat from deliberate "cyber attack" has been overstated[19], the focus on 'critical assets' has wide and important implications for operation of power systems and, in particular, vulnerability to and management of major unreliability events.

Regardless of whether or not events such as blocking of SCADA, communications failure or software are due to malicious attack, these are credible events that can have a major impact. As has been noted in various places in this Brochure and emphasised in Order 706, the apparently low likelihood of an event does not necessarily mean that it can be ignored. If it has a high impact, the risk associated with it will be significant enough for action to manage it to be justified, albeit that the installation of facilities to limit the extent of impact is likely to be more easily justified than facilities to prevent the event's occurrence.

In chapter 3 above, it was suggested that a new concept of security should be developed that goes beyond consideration solely of loss of 'primary' power systems and considers a broader range of unplanned events. The service losses associated with cyber attack, regardless of their cause, are a particularly important class of events within this concept that the 'cyber security' debate in North America can serve to highlight. As power system engineers know all too well, the reality is that software and communication failures can and do occur without malicious action. While the effects are usually localised and the impacts negligible, e.g. loss of first main protection on a single circuit while second main protection remains available, they can sometimes be huge, e.g. the unavailability of the energy management system (EMS) that was heavily implicated in the failure to avoid the major unreliability event in North America in August 2003 [16]. The belief of CIGRE WG C1.17 is that the consequences of loss of information and communication facilities need to be considered as part of an overall review of 'critical assets' and appropriate action taken.

8.9 References

[1] CIGRE C2.02.24, *Defence Plan against extreme contingencies*, CIGRE Brochure 316, April 2007.
[2] IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007.
[3] UCTE, *Final Report System Disturbance on 4 November 2006*, – see http://www.ucte.org/pdf/Publications/2007/Final-Report-20070130.pdf
[4] UCTE Expert Group on Power System Stability, *UCTE Master Plan for managing UCTE wide disturbances, Basic considerations and action plan / UCTE Guidelines and Rules for Defence Plan*, 2009.
[5] Amprion TSO Strom, "Investigations of resynchronisation of large isolated networks with different frequencies", *UCTE Expert Group Meeting*, Rome, February 2008.
[6] Transpower, "North Island 400 kV Upgrade Project Investment Proposal", 30 September 2005.

[18] At time of writing of this Brochure (in early 2009), NERC is working to revise the cyber security standards to incorporate improvements suggested in Order 706.
[19] There is some suggestion in the UK that 'cyber security' risks are being artificially 'talked up' by commercial entities that see an opportunity to make money out of the perceived dangers associated with old and apparently insecure information and communications technology even when there is little evidence that such risks really exist. (For an example scare story, see [17]). Indeed, it might even be the case that old equipment (often not interoperable with other systems) is less vulnerable than new equipment.

[7] Electricity Commission, “Draft decision on Transpower’s Auckland 400kV grid investment proposal”, 27 April 2006.
[8] Transpower, “North Island Grid Upgrade Project – Amended Proposal Application For Approval” 20 October 2006.
[9] Electricity Commission, “Final Decision on Transpower’s North Island Grid Upgrade Proposal”, 5 July 2007.
[10] Electricity Commission, “Reasons for Decision set out in Notice of Intention to Approve Transpower’s North Island Grid Upgrade Proposal”, 23 February 2007.
[11] Electricity Commission, “North Island Grid Upgrade Proposal - Final Decision Minority Opinion of Commissioner Pinnell”, 5 July 2007.
[12] National Grid, “ A REPORT TO THE AUTHORITY Pursuant to Paragraph 2 of Condition C14 of the Transmission Licence Low Frequency Demand Disconnection Relay Settings”, 25 January 2007.
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[14] North American Electricity Reliability Council, *The Electric Sector Response to the Critical Infrastructure Protection Challenge*, May 2002.
[15] NERC, *Glossary of Terms Used in Reliability Standards*, Feb. 12, 2008.
[16] U.S.-Canada Power System Outage Task Force, *August 14th Blackout: Causes and Recommendations*, April 2004.
[17] “Cyber-criminals target energy, engineering sectors”, IET News, 22 October 2008.

9 Conclusions

This Brochure has reported the work of CIGRE Working Group C1.17 in considering major unreliability events and the steps planners must take to enable them to be adequately managed where management concerns:

- reduction of the frequency of occurrence of such events;
- reduction of the impact of such events.

It has been argued that a number of developments in recent years are increasing the need for adequate management of power interruptions. These include

- a change in the function of system interconnection, from one of mutual assistance at times of high stress on individual systems to one of facilitating large electrical energy trades across wide areas;
- increased difficulty in building new overhead lines, whether due to rejection of planning consents or increased pressure from a diversity of stakeholders for quantified economic justification of investment;
- increased dependency in power system operation on a greater number of individual, independently owned actors and increased difficulty for system operators to obtain information from those actors;
- limited flexibility of new generating plant in comparison with older plant which are being used less or retired, the new generation being not only wind generation but also early installations of combined cycle gas turbines (CCGT);
- increased uncertainty in power transfers due to uncertainty in wind generation;
- decreased clarity of responsibility in disaggregated industries and between different interconnected systems;
- increase in size of interconnected grids, increasing the risk of event propagation; and
- the separation of generators from transmission owners, making co-ordinated planning more difficult.

In other words, the way the power system has to be operated is changing significantly and poses new challenges for the transmission system operators, who are responsible for overall system security, and for planners who are responsible for providing operators with the facilities they need.

A summary of notable events has been presented in Chapter 2, some of the more recent of which provide some evidence for the above pressures but all of which provide illustrations of the need for measures to manage power interruptions and exemplify a number of common mechanisms that have been described in Chapter 4.

Other working groups and task forces, among them those reported in [1][2], have addressed minimisation of the frequency of major disturbances; WG C1.17 has therefore concentrated on reduction of impact. The reduction of the initial extent of interruption of supply of power is the purpose of defence measures and the broad classes of these have been described in Chapter 4. The prevalence of these different measures around the world has been assessed by means of a survey, the results of which are described in Chapter 7. However, another dimension of impact is the duration of an interruption. If the initial interruption is, to some extent, controlled, the duration can be reduced. The most significant influence on the duration of a major unreliability event, though, is the effectiveness of a restoration plan and its implementation. Chapter 4 has therefore highlighted particular general issues associated with this.

Chapter 8 presented a number of case studies that provide details of implementations of defence measures in the UCTE system generally, France in particular and in Romania and Turkey. Particular issues arising as a consequence of the preponderance of nuclear generation in France in respect of restoration were also described as were recent developments in North America in respect of ‘cyber security’ of power system assets. Finally, two case studies highlighted some issues around the justification of investment in measures for the management of power interruptions. Justification of investment is addressed further in the next section below.

9.1 Justification of investment

Chapter 7 of this Brochure reported the outcome of a survey of utilities worldwide in respect of defence measures. A particular motivation for the survey was to find information on how utilities have justified investment in such measures.

It was found in the survey that most measures were put in place pre-liberalisation. In former electricity supply industry structures, engineering assessment of ‘risk’ (the product of probability and impact) usually sufficed to justify an investment.

In a liberalised environment with multiple players, private investment and a key role played by quasi-autonomous regulators, there is a particular emphasis on public demonstration of economic value. This will often be a complement of an assessment of engineering risk in the form of a demonstration of a proposed measure’s ‘cost-benefit’. Where this is simply relative to other measures for managing the same risk, this can be straightforwardly achieved. Where an authority seeks to treat an economic assessment on a more absolute basis, some form of monetary ‘damage function’ or ‘value of lost load’ (VOLL) is likely to be required. However, this is difficult to use because it is difficult to gain agreement from all stakeholders on what is a suitable VOLL. It is the belief of the Working Group responsible for producing this Brochure that one cannot hope to identify the ‘correct’ VOLL; rather, it must be subject to continuous consideration of the economic, social and political impacts of major unreliability events. This makes any case that a power system planner attempts to build for investment in measures for the management of major unreliability events vulnerable to particular circumstances or political vagaries. As if to confirm that, it was noted in Chapter 7 that a regulator’s agreement to recovery of the costs of a measure for containment of power interruptions is most likely to be gained

- soon after a major interruption;
- when the transmission system is identified as a ‘critical infrastructure’ vulnerable to terrorist attack;
- when stakeholders are reassured (through provision of suitable documentation) that all other reasonable measures are already being taken.

In respect of ‘critical infrastructure’, a significant development in North America has been the attention paid to ‘cyber security’. While some engineers, including members of WG C1.17, feel that the risks of cyber attack have been overstated, the attention paid to information and communication facilities usefully serves to highlight the serious consequences of loss of such facilities whatever the cause. Indeed, a number of major unreliability events worldwide have been heavily influenced by such losses. While this might motivate renewed attention to their reliability, it should also highlight the need for planning, commissioning and maintenance of adequate system defence measures.

Where a clear-cut economic case for measures for the containment of disturbances is not evident, a strategic case can be made for it if it can be shown that the investment cost is relatively modest compared to the potential economic and political cost of a widespread blackout, albeit that such a probability is very low and is indeterminate with any degree of confidence. In other words, the investment is justified regardless of the probability of occurrence of the major unreliability event and is concerned with, in effect, minimising the regret associated with not undertaking the investment. That is, where the *possible*, as opposed to probable, consequence of the decision not to invest is much greater than the cost of the investment, the investment is undertaken. Such an argument was used in a case study reported in Chapter 8.

9.2 A new understanding of 'security'

A description of the concept of power system security was presented in Chapter 3. This highlighted the fact that, notwithstanding system operators' application of conventions such as 'N-1' security, major unreliability events do occur, albeit rarely. Moreover, many of these are triggered by events that are apparently secured against.

It has been argued in Chapter 3 that major unreliability events are often initiated by system fault events in combination with circumstances that are not concerned with outages of primary power system assets such as overhead lines, underground cables, transformers, bus sections, circuit breakers, generators and so on and thus not usually detailed in security or reliability standards. These include

- a demand forecast error;
- an inter-area transfer forecast error;
- a ratings error (due, for example, to vegetation or adverse weather);
- a generator reactive power limit error; or
- unavailability of an accurate estimate of the system's current state.

Collectively, these circumstances are characterised by the state of the system and its limits not being what the operator believes them to be. Many of them may be aggravated or caused by failures of information or communication systems (as discussed in the 'cyber security' case study in Chapter 8).

Another issue concerns fault outages that occur outside of an area visible to a system operator but which nevertheless affect the area for which that system operator is responsible.

The view of WGC1.17 is that while the above events and circumstances might not drive 'classical' investment in additional network capacity or cause restriction of power flows in real time, because of their role in major unreliability events, they should be explicitly considered in cases for investment in defence measures designed to contain their impact were they happen. In addition, they may be used in operational timescales, rather as 'adaptive' security standards are now in a number of places. Their purpose then would be to minimise the risk of inadvertent interruption of load due to unnecessary action of defence measures through the clarification of when defence measures should be 'armed'.

9.3 Coordination of aspects of power system planning and operation

Chapter 5 of this Brochure has highlighted the importance for management of major unreliability events as well as normal system operation of all aspects of planning, design and operation of generating plant. As was described in chapter 4, continual operation of generation is critical to the power system's ability to proceed through a major disturbance, minimise the load interrupted and shorten restoration time. However, it has seemed to the members of Working Group C1.17 that aspects of coordination between transmission system planning and operation and, in particular, the performance of generation would benefit from renewed attention. Particular issues highlighted include adequate coordination of various generator protection systems and the designed capability of generation to contribute to control of the system under major disturbances.

As could be seen from the review of incidents in chapter 2, a number of major disturbances have been provoked or aggravated by a combination of factors related to protection and control systems. These factors fall into several categories including design deficiencies, installation flaws, equipment malfunction and human errors during maintenance and testing. The detailed performance of protection and control is sometimes beyond a power system planner's normal priorities and wider system behaviour outside those of protection and control engineers. In view of the role of protection and control in major unreliability events, it was argued in Chapter 6 that behaviour of these facilities under somewhat abnormal system conditions is worthy of particular attention.

Other aspects of coordination were also highlighted in Chapter 6:

- the importance of monitoring and data recording for post-event analysis;
- compliance testing of generators and enforcement of rules;
- the coordination of standards; and
- the coordination of different defence measures.

Recognising a planner's role in providing adequate facilities to operators and the difficulty of changing systems once they are in operation, many aspects of coordination should perhaps be highlighted especially for planners who have an opportunity to ensure adequate performance in advance of both local facilities and the system as a whole in advance of connection of new generation.

The coverage of technical coordination issues included in Chapters 5 and 6 of this Brochure has only scratched the surface of these subjects.

In view of the importance of some of the above issues for reliable operation of the power system as a whole and the interaction of planning and operation with issues with each other and with the design and operation of protection, WG C1.17 recommends that a new working group should be established. This is suggested to address at least the following:

- international best practice for generator performance under disturbances and enforcement of compliance with standards both at time of an application to connect and when operating;
- coordination of protection between 'local' objectives and 'system performance' considerations, both for network protection systems and the various forms of generator protection.

In view of the roles that system planners, operators and protection engineers each have in the above, it is recommended that any new working group should have input from study committees C1 (System Development and Economics), C2 (System Operation), B5 (Protection) and perhaps also A1 (Rotating Electrical Machines), with leadership and management undertaken by either C1 or C2. In view of its concern with modelling and system performance, some contribution from C4 (System Technical) may also be appropriate.

Other issues not considered explicitly by CIGRE WG C1.17 might also be addressed in future work. These include the following:

- issues associated with an operator being able to demonstrate the prudence of actions taken;
- the use of transmission spares and sharing of such resources between utilities; and
- assurance of the reliability of low voltage supplies to substations, in particular for protection and control systems;
- the contribution that rapid manual or automatic switching of loads between grid supply points at a sub-transmission or distribution level might make to the limitation of impact of loss of supply events, the importance of this for realisation of 'smart' or 'self-healing' grids and the extent to which it is limited by currently available facilities for reliable and precise identification of fault location.

9.4 References

[1] IEEE Task Force Report, *Blackout Experiences and Lessons, Best Practices for System Dynamic Performance, and the Role of New Technologies*, Final Report, IEEE, May 2007..
[2] CIGRE Task Force C2.02.24, *Defense plan against extreme contingencies*, Technical Brochure 316, CIGRE, April 2007.

A WG C1.17 Terms of Reference

WG C1.17	**Name of Convenor : Keith Bell**
Title of the Group : Planning to Manage Power Interruption Events	

Background : Power systems are planned and investments made to meet a defined level of redundancy or failure of certain systems assets (transmission, generation or demand). Even with this inherent security, failure of power systems will and do occur simply because it is impossible to completely eliminate risk. Increasingly networks are planned to their technical limits in a move to meet the demands of electricity markets and environmental constraints. The impact of network failure may become more widespread and the need to plan and manage these events is becoming more important. When failure occurs this should take place on a controlled basis and planners will need to define suitable strategies for managing the failure path and invest to achieve this.

This WG will identify suitable plans for the controlled management of failure due to unsecured events. Restoration plans are an integral part of the managed failure plan and will also be covered by this working group.

The WG's focus will not be 'classical' investments that are the subject of normal investment planning policies, but rather aspects such as protection schemes, defence plans, restoration plans, etc. Having identified the possible technical answers, the second main objective of the WG is to provide guidance on the justification of the corresponding investments to the stakeholders.

Deliverables

1. Guidance on good practice in management of system interruptions and restoration
2. Experience of special protection schemes and system defence plans, their use and justification to stakeholders of investment in automated facilities
3. Recommendations on criteria and techniques for identification and classification of risks enabling
   - Appropriate decision making in investment planning
   - Appropriate planning of special protection schemes and defence plans
4. Technical Brochure and Executive Summary in ELECTRA

Time Schedule : start January 2007 Final Report : February 2009

Comments from Chairmen of SCs concerned :

Approval by Technical Committee Chairman : Klaus Fröhlich
Date : Dec. 20, 2006

A.1 WG C1.17 Membership

Name	Country	Organisation
David Bones	*Australia*	Australian Energy Market Operator (AEMO)
Vlad Stanišić	*Canada*	OPGI - HYDRO
Wenjie Zhang	*Canada*	Manitoba Hydro
Sebastien Henry	*France*	RTE
Klaus Vennemann	*Germany*	Amprion Transportnetz
Tobias Paulun	*Germany*	At the start of the work, IAEW- RWTH Aachen. Now European Commodity Clearing AG
Alberto Berizzi	*Italy*	Politecnico di Milano
Mihai Cremenescu	*Romania*	Transelectrica SA
Leslie Naidoo	*South Africa*	Eskom
Robbie van Heerden	*South Africa*	Eskom
Pieter Schavemaker	*The Netherlands*	TenneT TSO
Siem Bruijns	*The Netherlands*	TenneT TSO
Algi Özkaya	*Turkey*	TEIAS (Turkish Transmission System Operator)
Darren Chan	*UK*	National Grid
Keith Bell	*UK*	University of Strathclyde
John Seelke	*US*	North American Electric Reliability Corporation (NERC)

B Survey Questionnaire

Background

CIGRE Working Group C1.17 on 'Planning to Manage Power Interruption Events' is concerned with preparedness for major unreliability events and measures to mitigate their impact in terms of their initial extent and the restoration time. The justification of investment in the required facilities is of particular interest since economic analysis of very rare, high impact events is usually problematic. The aim of the WG is to share useful experiences in these respects.

The purpose of this survey is to gather worldwide industry information on investments that have been made in defence measures that minimise or prevent the widespread collapse and interruption of the bulk power system due to system disturbance events of low or rare probability (sometimes called non-credible contingencies). We are also gathering information about restoration measures, including facilities, which enable a utility system to restore power after a widespread power outage. In addition to asking information about these measures, we are interested in the efforts to justify expenditure on the measures to company management or regulators. *Any information given is confidential and will only be used for statistical analysis.*

I. Defence Measures

Part I of the survey addresses defence measures. We *do not consider* protective relaying systems for the purpose of isolating faults or relays that operate to prevent damage to equipment as part of the defence measures applicable to this survey. Nor do we consider system responses to address defined credible contingencies (such as the loss of a single transmission circuit) as applicable to this survey. However, because terminology among utilities varies, we have developed the following definitions for the purpose of this survey.

a. A Special Protection Scheme (SPS) (also called Remedial Action Scheme (RAS)) is designed to detect abnormal system conditions and take automatic corrective action to maintain acceptable voltages, acceptable facility loadings and system stability. An SPS may be "armed" or "disarmed" according to system conditions, and it may take seemingly unrelated but pre-planned actions based upon detected system conditions. SPS actions include tripping of system elements, generation rejection, generator runback, load shedding, etc.
b. Under-frequency load shedding systems shed load at pre-set frequencies in order to arrest the frequency decay resulting from the sudden loss of generation.
c. Under-voltage load shedding systems shed load at pre-set voltage levels in order to arrest voltage decay resulting from the sudden loss of reactive power supplied by generators or other reactive sources, or unexpected increase in reactive demand.
d. An "Other" category is provided for approaches that do not fit in the categories above. These might include system "islanding" schemes, the installation of devices such as static var compensators (SVC), static synchronous compensators (STATCOM), tap changer blocking, or other approaches to minimise or prevent widespread bulk supply power interruptions.

II. Restoration Measures

Part II of the survey addresses system restoration measures. System restoration measures are necessary to ensure an orderly and rapid return to service for the bulk power system after a major interruption in demand has occurred.

The survey begins on the next page.

Utility Name:
Contact Person Name:
Contact Person E-mail Address:

PART I. DEFENCE MEASURES

Please answer the following questions for each defence measure that your utility employs or plans to employ to minimise or prevent the widespread collapse and interruption of power due to system disturbances. Please check all that apply in the boxes (☐) shown.

☐ **Special Protection System(s)**[20]
Briefly describe your SPS:

SPS questions	Answers
a. Approximate year of installation (or planned if future)	a.
b. Is measure required to meet planning and/or operational standard? (Yes/No)	b.
c. Was a cost-benefit analysis performed to compare the scheme against another transmission option (e.g., a new circuit)? (Yes/No)	c.
Continuation of response "c": ***Why*** was the measure selected? **Answer all questions that apply.**	DO NOT ANSWER IN THIS BOX
i. Cost – see the sub-parts below that address cost: 1. Was the value of possible load lost taken into consideration? (Yes/No)	c.i.1.
2. If "Yes," what is the typical ratio of: value of load lost to the cost of serving normal load? For example, if load lost was valued at $10/kWh, while the cost of serving normal load is $0.15/kWh, the ratio would be 66.7.	c.i.2.
3. If "Yes," what probability of an event was assumed in the analysis (once every year, once every 5 years, etc.)?	c.i.3.
ii. Reliability of the measure compared with others. (Yes/No)	c.ii.
iii. Other reasons (please explain, in separate sheet if necessary, e.g., technical or strategic).	c.iii.
d. If "No" to "b" above, what are the reasons for implementing the measure? **Answer all questions that apply.**	DO NOT ANSWER IN THIS BOX
i. A historical decision for which detailed justification is no longer available, but which we continue to maintain. (Yes/No)	d.i.
1. If "Yes," how is the continued maintenance cost justified? (Please explain in a separate sheet if necessary	d.i.1
ii. Imposed by regulator. (Yes/No)	d.ii.
iii. Cost advantage based on probability of an event. (Yes/No)	d.iii.
1. If "yes," what probability of an event was assumed (once every year, once every 5 years, etc)?	d.iii.1
iv. Financial incentives offered by regulator. (Yes/No)	d.iv.

[20] Please see description of Special Protection Systems on the first page.

v. Government, regulator, or public pressure. (Yes/No)	d.v.
vi. Other reasons (Please explain in separate sheet if necessary)	d.vi
SPS questions cont'd	**Answers**
e. Did significant power interruptions occur *prior* to the decision to invest in the measure? (Yes/No).	e.
i. If "yes" about how many interruptions occurred?	e.i.
f. Since installation of your defence measure, has it been called to operate? (Yes/No)	f.
i. If "yes," did it operate satisfactorily? (Yes/No)	f.i.

☐ **Under-frequency load shedding**[21]

UFLS questions	**Answers**
a. Approximate year of installation (or planned if future)	a.
b. Is measure required to meet planning and/or operational standard? (Yes/No)	b.
c. Was a cost-benefit analysis performed to compare the measure against another transmission option (e.g., a new circuit)? (Yes/No)	c.
Continuation of response "c": Why was the measure selected? **Answer all questions that apply.**	DO NOT ANSWER IN THIS BOX
i. Cost – see the sub-parts below that address cost: 1. Was the value of possible load lost taken into consideration? (Yes/No)	c.i.1.
2. If "Yes," what is the typical ratio of: value of load lost to the cost of serving normal load? For example, if load lost was valued at $10/kWh, while the cost of serving normal load is $0.15/kWh, the ratio would be 66.7.	c.i.2.
3. If "Yes," what probability of an event was assumed in the analysis (once every year, once every 5 years, etc.)?	c.i.3.
ii. Reliability. (Yes/No)	c.ii.
iii. Other reasons (Please explain in separate sheet if necessary, e.g., technical or strategic)	c.iii.
d. If "No" to "b" above, what are the reasons for implementing the measure? **Answer all questions that apply.**	DO NOT ANSWER IN THIS BOX
i. A historical decision for which detailed justification is no longer available, but which we continue to maintain. (Yes/No)	d.i.
1. If "Yes," how is the continued maintenance cost justified? (Please explain in a separate sheet if necessary)	d.i.1
ii. Imposed by regulator. (Yes/No)	d.ii.
iii. Cost advantage based on probability of an event. (Yes/No)	d.iii.
1. If "yes," what probability of an event was assumed (once every year, once every 5 years, etc)?	d.iii.1
iv. Financial incentives offered by regulator. (Yes/No)	d.iv.
v. Government, regulator, or public pressure. (Yes/No)	d.v
vi. Other reasons (Please explain in separate sheet if necessary)	d.vi.
UFLS questions cont'd	**Answers**
e. Did significant power interruptions occur *prior* to the decision to invest in the measure? (Yes/No).	e.
i. If "yes" about how many interruptions occurred?	e.i.
f. Since installation of your defence measure, has it been called to operate? (Yes/No)	f.
i. If "yes," did it operate satisfactorily? (Yes/No)	f.i.

[21] Please see description of under-frequency load shedding on the first page.

☐ **Under-voltage load shedding**[22]

UVLS questions	Answers
a. Approximate year of installation (or planned if future)	a.
b. Is measure required to meet planning and/or operational standard? (Yes/No)	b.
c. Was a cost-benefit analysis performed to compare the measure against another transmission option (e.g., a new circuit)? (Yes/No)	c.
Continuation of response "c": **Why** was the measure selected? **Answer all questions that apply.**	DO NOT ANSWER IN THIS BOX
i. Cost – see the sub-parts below that address cost: 1. Was the value of possible load lost taken into consideration? (Yes/No)	c.i.1.
2. If "Yes," what is the typical ratio of: value of load lost to the cost of serving normal load? For example, if load lost was valued at $10/kWh, while the cost of serving normal load is $0.15/kWh, the ratio would be 66.7.	c.i.2.
3. If "Yes," what probability of an event was assumed in the analysis (once every year, once every 5 years, etc.)?	c.i.3.
ii. Reliability. (Yes/No)	c.ii.
iii. Other reasons (Please explain in separate sheet if necessary, e.g., technical or strategic)	c.iii.
d. If "No" to "b" above, what are the reasons for implementing the measure? **Answer all questions that apply**.	DO NOT ANSWER IN THIS BOX
i. A historical decision for which detailed justification is no longer available, but which we continue to maintain. (Yes/No)	d.i.
1. If "Yes," how is the continued maintenance cost justified? (Please explain in a separate sheet if necessary	d.i.1.
ii. Imposed by regulator. (Yes/No)	d.ii.
iii. Cost advantage based on probability of an event. (Yes/No)	d.iii.
1. If "yes," what probability of an event was assumed (once every year, once every 5 years, etc)?	d.iii.1
iv. Financial incentives offered by regulator. (Yes/No)	d.iv.
v. Government, regulator, or public pressure. (Yes/No)	d.v.
vi. Other reasons (Please explain in separate sheet if necessary)	d.vi.
UVLS questions cont'd	**Answers**
e. Did significant power interruptions occur *prior* to the decision to invest in the measure? (Yes/No).	e.
i. If "yes" about how many interruptions occurred?	e.i.
f. Since installation of your defence measure, has it been called to operate? (Yes/No)	f.
i. If "yes," did it operate satisfactorily? (Yes/No)	f.i.

[22] Please see description of under-voltage load shedding on the first page.

Please describe *other* defence measures you have or plan to install:

☐ **Other defence measures**[23] **Briefly describe the measure:**

Other defence measure questions	**Answers**
a. Approximate year of installation (or planned if future)	a.
b. Is measure required to meet planning and/or operational standard? (Yes/No)	b.
c. Was a cost-benefit analysis performed to compare the measure against another transmission option (e.g., a new circuit)? (Yes/No)	c.
Continuation of response "c": **Why** was the measure selected? **Answer all questions that apply.**	DO NOT ANSWER HERE IN THIS BOX
i. Cost – see the sub-parts below that address cost: 1. Was the value of possible load lost taken into consideration? (Yes/No)	c.i.1.
2. If "Yes," what is the typical ratio of: value of load lost to the cost of serving normal load? For example, if load lost was valued at $10/kWh, while the cost of serving normal load is $0.15/kWh, the ratio would be 66.7.	c.i.2.
3. If "Yes," what probability of an event was assumed in the analysis (once every year, once every 5 years, etc.)?	c.i.3.
ii. Reliability. (Yes/No)	c.ii.
iii. Other reasons (Please explain in separate sheet if necessary, e.g., technical or strategic)	c.iii.
d. If "No" to "b" above, what are the reasons for implementing the measure? **Answer all questions that apply.**	DO NOT ANSWER IN THIS BOX
i. A historical decision for which detailed justification is no longer available, but which we continue to maintain. (Yes/No)	d.i.
1. If "Yes," how is the continued maintenance cost justified? (Please explain in a separate sheet if necessary	d.i.1.
ii. Imposed by regulator. (Yes/No)	d.ii.
iii. Cost advantage based on probability of an event. (Yes/No)	d.iii.
1. If "yes," what probability of an event was assumed (once every year, once every 5 years, etc)?	d.iii.1
iv. Financial incentives offered by regulator. (Yes/No)	d.iv.
v. Government, regulator, or public pressure. (Yes/No)	d.v.
vi. Other reasons (Please explain in separate sheet if necessary)	d.vi.
e. Did significant power interruptions occur *prior* to the decision to invest in the measure? (Yes/No).	e.
i. If "yes" about how many interruptions occurred?	e.i.
f. Since installation of your defence measure, has it been called to operate? (Yes/No)	f.
i. If "yes," did it operate satisfactorily? (Yes/No)	f.i.

[23] See a description of typical other defence measures on the first page.

Utility Name:
Contact Person Name:
Contact Person E-mail Address:

PART II. RESTORATION MEASURES

Please answer the following questions for each restoration measure that your utility employs to restore the bulk power system. Please check all that apply in the boxes (☐) shown.

☐ Generator Black Start

<table>
<tr><th>Generator Black Start questions</th><th>Answers</th></tr>
<tr><td>a. What is the proportion of your system's generation capacity with black start capability with respect to your total maximum demand? (MW Gen. with black start/MW demand)</td><td>a.</td></tr>
<tr><td>b. What type of generation has black start capability and how often is each type tested (e.g., every two years)? Please exclude any generators used to black start other generators unless you consider them as part of your generation fleet that is normally operated (i.e., economically dispatched). The % MW by type are the % of MW of that type with black start capacity to the total MW in question "a." with black start capability:[24]
<table>
<tr><th>Generation Type with Black Start Capability</th><th colspan="2">% of Black Start Capable MW</th><th>Testing Frequency</th></tr>
<tr><td>Diesel</td><td></td><td>%</td><td></td></tr>
<tr><td>Simple cycle gas turbine</td><td></td><td>%</td><td></td></tr>
<tr><td>Combined cycle gas turbine</td><td></td><td>%</td><td></td></tr>
<tr><td>Fossil steam turbine</td><td></td><td>%</td><td></td></tr>
<tr><td>Nuclear steam turbine</td><td></td><td>%</td><td></td></tr>
<tr><td>Hydro</td><td></td><td>%</td><td></td></tr>
<tr><td>Other</td><td></td><td>%</td><td></td></tr>
<tr><td>Total (=100% of black start MW)</td><td>0</td><td>%</td><td></td></tr>
</table></td><td>DO NOT ANSWER IN THIS BOX</td></tr>
<tr><td rowspan="2">c. Do your black start plans rely (in part or completely) on power from external power grids that your system is interconnected with? (Yes/No)
i. If "Yes," what happens if they are shutdown? Please explain below or in separate sheet if necessary.</td><td>c.</td></tr>
<tr><td>c.i.</td></tr>
<tr><td>d. Is your system's black start capability required to meet an external planning and/or operational standard (i.e., a standard that is imposed by a separate entity such as a regulator or transmission system operator)? (Yes/No)</td><td>d.</td></tr>
</table>

[24] As an example, suppose in question "a" you report that 15% of your generation has black start capability. This was derived by taking your total black start capability (say 3,000 MW) and dividing it by your total generation (say 20,000 MW) to arrive at 15% (3000/20000). In question "b" we want to know what type of generation makes up these 3,000 MW of black start capable capacity. If 900 MW are diesel engines, the % of diesel would be answered as 30% (900/3000). All types of black start capable capacity would add up to 100% in the last highlighted line.

Generator Black Start questions cont'd	Answers
e. If "d" was answered "Yes," skip this section and section "f." If "d." was answered as "No," provide your reasons for having black start capability. **Answer all questions that apply.**	DO NOT ANSWER IN THIS BOX
i. A historical decision for which detailed justification is no longer available, but which we continue to maintain. (Yes/No)	e.i.
1. If "Yes," how is the continued maintenance cost justified? (Please explain in a separate sheet if necessary	e.i.1
ii. Economic Cost – see the sub-parts below that address cost:	DO NOT ANSWERIN THIS BOX
1. The *economic cost* of delay in load restoration was *unacceptable*? (Yes/No)	e.ii.1.
2. If e.ii.1 was "Yes," was cost of delay quantified? (Yes/No)?	e.ii.2.
3. If e.ii.2 was "Yes," what is the typical ratio of: the value of load restoration delayed to the cost of serving normal load? For example, if load restoration delayed was valued at $10/kWh, while the cost of serving normal load is $0.15/kWh, the ratio would be 66.7.	e.ii.3.
4. If e.ii.2 was "Yes," what probability of an event was assumed in the analysis (once every year, once every 5 years, etc.)	e.ii.4.
iii. The *socio/political cost* of delay in restoration was *unacceptable*. (Yes/No)	e.iii
iv. Other reasons (Please explain, e.g., Regulator).	e.iv.
f. Did significant power interruptions occur *prior* to the decision to invest in black start? (Yes/No).	f.
i. If "yes" about how many interruptions occurred?	f.i.
g. Since installation of black start, has it been called to operate? (Yes/No)	g.
i. If "yes," did it operate satisfactorily? (Yes/No)	g.i.

☐ Restoration Plans

Restoration Plans questions	Answers
a. Please describe your restoration plans for bulk power system outages in the next page.	a. PLEASE ANSWER ON NEXT PAGE
b. Are your restoration plans required to meet an *external* planning and/or operational standard (i.e., a standard that is imposed by a separate entity)? (Yes/No)	b.
c. If "b" was answered "Yes," skip this section and section "d." If "b." was answered as "No," please provide your reasons for coordinated restoration plans. **Answer all questions that apply.**	DO NOT ANSWER IN THIS BOX
i. A historical decision for which detailed justification is no longer available, but which we continue to maintain. (Yes/No)	c.i.1.
1. If "Yes," how is the continued maintenance cost justified? (Please explain in a separate sheet if necessary	c.i.1
ii. Economic Cost – see the sub-parts below that address cost:	DO NOT ANSWER IN THIS BOX
1. The *economic cost* of delay in load restoration was *unacceptable*? (Yes/No)	c.ii.1.
2. If c.ii.1 was "Yes," was cost of delay quantified? (Yes/No)?	c.ii.2
3. If c.ii.2 was "Yes," what is the typical ratio of: value of load restoration delayed to the cost of serving normal load? For example, if load restoration delayed was valued at $10/kWh, while the cost of serving normal load is $0.15/kWh, the ratio would be 66.7.	c.ii.3
4. If c.ii.2 was "Yes," what probability of an event was assumed in the analysis (once every year, once every 5 years, etc.)?	c.ii.4.
iii. The *socio/political cost* of delay in restoration was *unacceptable*. (Yes/No)	c.iii
iv. Other reasons (please explain, e.g., Regulator).	c.iv
d. Did significant power interruptions occur *prior* to the decision to invest in the measure? (Yes/No).	d.
i. If "yes" about how many interruptions occurred?	d.i.
e. Since installation of your restoration measure, has it been called to operate? (Yes/No)	e.
i. If "yes," did it operate satisfactorily? (Yes/No). Explain in a separate sheet if necessary.	e.i.

BRIEF DESCRIPTION OF RESTORATION PLANS:

1. Is your restoration plan coordinated with neighbouring utilities?

2. How often are your restoration plans rehearsed?

3. Are there joint rehearsals with other transmission system operators?

4. What is the estimated timescale of restoration, assuming a total blackout? (e.g., 30% within 2-6 hours, 70% within 12 hours)

5. Are there strategic spares of plant stocked to aid speedy restoration in case of extensive plant damage?

6. Is there an agreement with other utilities to help with staff for restoration?

7. Is there a nominated central control entity for restoration if blackout is across two or more utilities?

8. Describe any other restoration measures not mentioned previously.