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Abstract

The objective of this report is to present the current transmission system operator (TSO) reliability practices, grid codes and drivers for and barriers against probabilistic reliability criteria. The report focuses on the European practices but also presents some cases from other continents. Furthermore, practices regarding multi-area and multi-agent issues are discussed in the European context.

The inputs to this report are the opinions of European TSOs received from a questionnaire survey, a one-day workshop, a review of existing and coming grid codes, the experience from other continents, regulation practices, and literature. The questionnaire responses cover 9 TSOs from the Nordic countries and the Continental Europe.

The current reliability practice in Europe is mainly following the N-1 criterion but there are different practical implementations. Experiences of using probabilistic methods are reported: The North American Electric Reliability Corporation, NERC has started using probabilistic tools in North America and there is already some experience on them for transmission systems.

The most important drivers for probabilistic reliability criteria are more efficient grid use, a better balance between reliability and costs, more transmission capacity given to the market, actually getting an estimate for the reliability, and connecting large shares of wind or other variable production into the system.

The following items have been identified to be barriers: the methods are laborious, complex and take too much time to use. It is challenging to model the consequences of a contingency, there are not sufficient and reliable statistical or other data available for the evaluation, and there is a reluctance of change and little experience is gained so far. Moreover, it would be difficult to understand probabilistic reliability criteria and justify their impact on society.

Regulation can be a driver or a barrier, depending on the contents of the rules.

The report provides important aspects that the GARPUR project should take into account when developing new reliability criteria for power systems.

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EXECUTIVE SUMMARY

This report describes the current transmission system operator (TSO) reliability practices along with the grid codes. It also presents drivers for and barriers against probabilistic reliability criteria. The report focuses on the European practices but also presents some cases from other continents. Due to the multi-area and multi-agent nature of many power systems, these issues are also discussed within this document in the European context.

The inputs to this report are the opinions of European TSOs received from a questionnaire survey, a one-day workshop, a review of existing and coming grid codes, experiences from other continents, regulation practices, and literature. The questionnaire responses cover 9 TSOs from the Nordic countries and the Continental Europe. Despite the limited number, the responses are regarded sufficiently representative for Europe, since they represent different system sizes, characteristics and control zones.

The current reliability practice in Europe is based on the N-1 criterion but there are different practical implementations between different TSOs and between different time horizons. Experiences of using probabilistic methods are also reported. For example, the North American Electric Reliability Corporation, NERC has started using probabilistic tools in North America, and there is already some experience on them for transmission systems.

The background of the widespread international interest for probabilistic methods is the need to achieve a better trade-off between the costs and reliability in power systems. The implementation of probabilistic methods in grid planning and operation is, however, a considerable challenge. The advantages and disadvantages deserve careful consideration. The international observations indicate that deterministic criteria still are the main tools in planning and operation of power systems.

The most important drivers identified are more efficient grid use (i.e. having smaller security margins), a better balance between the costs and reliability, more transmission capacity given to the market, getting an estimate for the reliability, and connecting large shares of wind or other variable production into the systems.

The following items have been identified to be barriers: the methods are laborious, complex and take too much time to use. It is challenging to model the consequences of a contingency and there are not sufficient and reliable statistical or other data available for the evaluation. The lack of data is an important issue. The methods need reliability data, data on variable generation as well as data on socio-economic costs. Some of these data are available, but access to data, sharing and publishing data, as well as the accuracy of data are issues that need to be solved. Finally, there is a reluctance of change and little experience is gained so far. These barriers mean that the probabilistic methods should be implementable, understandable and possible to justify to the society. To achieve the latter, it is necessary to develop methodology to evaluate the socio-economic benefit of changes in the reliability level.

Regulation can be seen as a barrier as stated by TSOs in the questionnaire. However, regulation can also be seen as a driver towards probabilistic reliability criteria as examples from Norway and the Netherlands show. Therefore, in the European context, the regulators (ACER) should provide incentives (and rules) to use probabilistic criteria, if these criteria are to be implemented by TSOs in practice.

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1 INTRODUCTION

This deliverable is the second deliverable of the work package 1 (WP1) of the GARPUR project concentrating on the current practices for reliability management in power systems, multi-area and multi-agent practices in the European context, expected impact from known coming grid codes and drivers and barriers for new reliability standards. This report serves as a basis for the rest of the GARPUR project.

The objective of Task 1.2 and Task 1.3 in WP1 is to analyse the approaches currently used by TSOs to ensure power system reliability while focusing on the variations in implementation of the N-1 criterion. More precisely, D1.2 should:

- Provide an overview of the current implementation of the grid codes in force, and assess similarities and differences in how the N-1 criterion is implemented.
- Look into R&D status regarding reliability criteria (deterministic N-k, probabilistic, combinations) and coming grid codes (in public consultation and approval stage), and assess expected implications for reliability management in power system planning and operation.
- Identify drivers, possibilities and barriers for defining and introducing new reliability criteria.

This deliverable combines the contributions of the tasks T1.2 and T1.3 wherein the topics are the current reliability management approaches as well as drivers and barriers for new reliability standards for the European power system.

Task 1.2 consists of the following sub-tasks:

- Current practices and initially identified priorities for improvement. The current situation and objectives are reviewed and requirements for improvement and main obstacles are identified by performing a questionnaire survey among the TSO partners of the GARPUR project.
- Grid codes under development and state of the art regarding development of new reliability criteria. The grid codes in public consultation and/or approval stage are reviewed.
- Interesting reliability management trends outside Europe that can serve as an inspiration for future improvement of the European practice are reviewed. Experience from North America, New Zealand and Brazil is presented and discussed.

Task 1.3 identifies the drivers and barriers for new reliability standards for the European power system using a triangulation of:

- Questionnaire answers provided by the involved TSOs of the GARPUR project;
- Existing literature;
- Discussions and comments obtained in a GARPUR TSO workshop on 7 April 2014.

This approach ensures a wide range of aspects from the industry and scientific society.

The first deliverable D1.1 of WP1 (GARPUR Consortium 2014) focused on the state of the art regarding reliability assessment methodologies for power systems and lessons learned from other fields, and socio-economic impact assessment.

The report is organized as follows: In Chapter 2, terms and definitions are presented. Chapter 3 presents current reliability management practices in Europe. In Chapter 4, a view on practices in North America, New Zealand and Brazil is described. To consider also the forthcoming changes in European network codes, a review of the status of the network codes of ENTSO-E is presented in Chapter 5. Chapter 6 identifies drivers and barriers for new reliability criteria based on questionnaire answers submitted by

TSOs, literature and GARPUR workshop contributions. Finally, in Chapter 7, a summary is presented and conclusions are drawn in Chapter 8.

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2 TERMS, DEFINITIONS AND ABBREVIATIONS

2.1 Terms and Definitions

Common grid model
Common grid model (CGM) means the European-wide or multiple-TSOs-wide data set, created by the European merging function, through the merging of relevant data (ENTSO-E 2013a).

Connection point
Connection point is the interface at which the power generating module, demand facility, distribution network or closed distribution network is connected to a transmission system, distribution network or closed distribution network (ENTSO-E 2013a).

Consequence
Consequence is the outcome of an event (ISO 2009).

Note: There can be different types of consequences: technical (like interruption), economic or environmental consequences, consequences on personnel/ consumers safety, etc. See GARPUR Delivarable D1.1 (GARPUR Consortium 2014).

Contingency
A contingency is the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency may also include multiple components, which are related by situations leading to simultaneous component outages. (ENTSO-E 2004a)

Contingency list
Contingency list means the list of contingencies to be simulated in the contingency analysis in order to test the compliance with the operational security limits before or after a contingency took place (ENTSO-E 2013a).

Control area
Control area is a part of the interconnected electricity transmission system controlled by a single TSO (ENTSO-E 2004a).

Costs of energy not supplied (CENS)
Costs of energy not supplied represent interruption costs (Kjølle et al. 2009, Kjølle et al. 2008).

Demand facility
Demand facility means a facility which consumes electrical energy and is connected at one or more connection points to the network. For the avoidance of doubt a distribution network and/or auxiliary supplies of a power generating module are not to be considered a demand facility (ENTSO-E 2013a).

Disturbance
Disturbance is an unplanned event that produces an abnormal system condition (ISO 2009).

End-user
End-user is the ultimate consumer of a finished product (An Encyclopedia Britannia Company 2014). In this document, an end-user is an electricity consumer.

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Energy not supplied
Energy not supplied is the estimated energy which would have been supplied to end-users if no interruption and no transmission restrictions had occurred (Nordel 2009).

Event
The general term event is defined as occurrence of a particular set of circumstances (ISO 2009). In recent books (Rausand 2011, Hokstad et al. 2013) the authors distinguish between hazardous and initiating events, and accident scenarios (sequence of events). Often in power systems, terms like failure events and extraordinary (or exceptional) events, are used.

Exceptional contingency
Exceptional contingency means the loss of a busbar or more than one element such as, but not limited to: A common mode fault with the loss of more than one power generating module, a common mode fault with the loss of more than one AC or DC line, a common mode fault with the loss of more than one transformer (ENTSO-E 2013a).

Failure
A failure is the termination of the ability of an item to perform a required function. After failure the item has a fault (IEC 2014, IEV ref 191-04-01).

Fault
A fault is the state of an item characterized by inability to perform a required function, excluding the inability during preventive maintenance or other planned actions, or due to lack of external resources (IEC 2014, IEV ref 191-05-01).

Local
Local means the qualification of an alert, emergency or blackout state when there is no risk of extension of the consequences outside of the responsibility area of a single TSO (ENTSO-E 2013a).

N-0 criterion
The N-0 criterion means accepting more severe consequences after certain faults (see the text before Question 19 in the questionnaire in Appendix 1).

N-1 criterion
The N-1 criterion is a principle according to which the system should be able to withstand at all times a credible contingency – i.e., unexpected failure or outage of a system component (such as a line, transformer, or generator) – in such a way that the system is capable of accommodating the new operational situation without violating operational security limits. (The definitons is partly based on ENTSO-E documents (ENTSO-E 2004a) and (ENTSO-E 2013d).

Note 1: The N-1 criterion is a deterministic reliability criterion.
Note 2: There is no common definition of N-1 in literature. It is defined in several different ways which are more or less similar. See e.g. GARPUR Deliverable D1.1 (GARPUR Consortium 2014) for more definitions.

N-1 principle
See N-1 criterion.
The terms N-1 criterion and N-1 principle are used interchangeably in this delivable.

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N-1 situation
The N-1 situation is defined as the status of the TSO´s responsibility area after an event defined in the contingency list (ENTSO-E 2009c, p. P3-5).

Normal state
According to ENTSO-E's Network Code on Operational Security, published in September 2013 (ENTSO-E 2013b), a normal state means the system state where the system is within operational security limits in the N-situation and after the occurrence of any contingency from the contingency list, taking into account the effect of the available remedial actions.

A different definition can be found in the Continental Europe Operational Handbook and its Policy 5 Emergency operations (ENTSO-E 2010a, p. 5-3). In this handbooka a normal state means that there is no risk for interconnected system operation. All consumption and production are in balance and requirements on ancillary services and framework conditions are met; frequency, voltage and power flows are within their predefined and allowed limits (thresholds) and reserve (margins) are sufficient to withstand pre-defined contingencies. Operation is within normal limits, taking into account remedial actions effects.

Operational security
Operational security means the transmission system capability to retain a normal state or to return to a normal state as soon and as close as possible, and is characterized by its thermal limits, voltage constraints, short-circuit current, frequency reference value and stability limits (ENTSO-E 2013b p. 9).

Operational security analysis
Operational security analysis means the entire scope of the computer based, manual and combined activities performed in order to assess operational security of the transmission system, including but not limited to: processing of telemetered real-time data through state estimation, real-time load flows calculation, load flows calculation during operational planning, contingency analysis in real-time and during operational planning, dynamic stability assessment, real-time and offline short circuit calculations, system frequency monitoring, reactive power and voltage assessment (ENTSO-E 2013b p. 12).

Operational security limit
Operational security Limit means the acceptable operating boundaries: thermal limits, voltage limits, short-circuit current limits, frequency and dynamic stability limits (ENTSO-E 2013b p. 12).

Outage
An outage is the state of a component or system when it is not available to properly perform its intended function due to some event directly associated with that component or system (IEEE 1997, p. 5).

Out-of-range contingency
Out-of-range contingency means the simultaneous loss, without a common mode fault, of several transmission system elements such as, but not limited to: two independent lines, a substation with more than one busbar, a tower with more than two circuits, one or more power generating facilities with a total lost capacity exceeding the reference incident (ENTSO-E 2013a, p. 250 and ENTSO-E 2013b, p. 12)

Power system reliability
Power system reliability means the probability that an electric power system can perform a required function under given conditions for a given time interval (IEC 2014, IEV ref 617-01-01).

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Note 1: Reliability quantifies the ability of an electric power system to supply adequate electric service on a nearly continuous basis with few interruptions over an extended period of time (IEC 2014, IEV ref 617-01-01).

Note 2: The definitions above describe the reliability from the power system perspective. From the end-user perspective, reliability of supply is frequently used as a term describing how reliability is perceived at a local delivery point. See note 3 for how reliability of supply may be measured.

Note 3: The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service (Kundur et al. 2004, p. 1393).

Note 4: Reliability of a power system can be divided into power system security and power system adequacy (Kundur et al. 2004).

Power system security is the ability of the power system to withstand sudden disturbances such as short circuits or un-anticipated loss of system components. Security refers to the degree of risk in its ability to survive imminent disturbances (contingencies) without the interruption of customer service (Kundur et al. 2004 and ENTSO-E 2014a). Another aspect of security is system integrity, which is the ability to maintain interconnected operations. Integrity relates to the preservation of interconnected system operation, or the avoidance of uncontrolled separation, in the presence of specified severe disturbances (ENTSO-E 2014a).

Power system adequacy is the ability of the system to supply the aggregate electric power and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of the system components (Kundur et al. 2004).

Reactive power
Reactive power is the imaginary component of the apparent power at fundamental frequency, usually expressed in kilovar (kvar) or megavar (Mvar) (ENTSO-E 2013a).

Re-dispatch (also Redispatch)
Redispatching means a measure activated by one or several system operators by altering the generation and/ or load pattern, in order to change physical flows in the transmission system and relieve a physical congestion (ENTSO-E 2013a, p. 250).

Responsibility area
Responsibility area means a coherent part of the interconnected transmission system including interconnectors, operated by a single TSO with connected demand facilities, or power generating modules, if any (ENTSO-E 2013a, p. 251).

Reliability management
Power system reliability management means to take a sequence of decisions under uncertainty. It aims at meeting a reliability criterion, while minimising the socio-economic costs of doing so.

Remedial action
Remedial action means any measure applied by a TSO in order to maintain operational security. In particular, remedial actions serve to fulfil the N-1-criterion and to maintain operational security limits (ENTSO-E 2013a, p. 250).

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Significant grid user

Significant grid user (SGU) means the existing and new power generating facility and demand facility deemed by the TSO as significant because of their impact on the transmission system in terms of the security of supply including provision of ancillary services (ENTSO-E 2013a, p. 251).

Synchronous area

Synchronous area means an area covered by interconnected TSOs with a common System frequency in a steady-state such as the synchronous areas Continental Europe (CE), Great Britain (GB), Ireland (IRE) and Northern Europe (NE) (ENTSO-E 2013a, p. 251).

Topology

Topology means necessary data about the connectivity of the different transmission system or distribution network elements in a substation. It includes the electrical configuration and the position of circuit breakers and isolators (ENTSO-E 2013a, p. 252).

Transitory admissible overloads

Transitory admissible overloads means the temporary overloads of transmission system elements which are allowed for a limited period and which do not cause physical damage to the transmission system elements and equipment as long as the defined duration and thresholds are respected (ENTSO-E 2013a, p. 252).

Transmission system

Transmission system means the electric power network used to transmit electric power over long distances within and between member states. The transmission system is usually operated at the 220 kV and above for AC or HVDC, but may also include lower voltages (ENTSO-E 2013a, p. 252).

Value of lost load

Value of lost load (VOLL) is defined as a measure of the cost of unserved energy (the energy that would have been supplied if there had been no outage) for consumers. It is generally normalised in €/kWh (ENTSO-E 2013c, p. 55).

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2.2 Abbreviations

AC	alternating current
BPS	bulk power system
CAPEX	capital expenditure
CENS	cost of energy not supplied
DADS	demand response availability data system
DSO	distribution system operator
ENTSO-E	European network of transmission system operators for electricity
ENTSO-E RG CE	European network of transmission system operators for electricity Regional Group Continental Europe
ERCOT	Electric Reliability Council of Texas
EUE	expected unserved energy
FERC	the U.S. Federal Energy Regulatory Commission
FMEA	failure mode and effect analysis
GADS	generating availability data system
HILF	high impact low frequency
HVDC	high voltage direct current
LIHF	low impact high frequency
LOLH	annual loss-of-load hours
LTRA	long-term reliability assessment
MRA	metrics reporting area
NERC	the North American Electric Reliability Corporation
OPS	operational planning & scheduling network code
OS	operational security network code
SRC	Security and Reliability Council
SRI	severity risk index
TADS	transmission availability data system
TPL	transmission planning
TSO	transmission system operator
UCTE	Union for the Co-ordination of Transmission of Electricity
VOLL	value of lost load
WSCC	Western Systems Coordinating Council

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3 EUROPEAN RELIABILITY MANAGEMENT: CURRENT PRACTICES

The current planning and operation of the European power system is based on the N-1 principle. This chapter deals with the current practices for reliability management in Europe. In Section 3.1, the mandatory rules given by the current ENTSO-E Continental Europe Operation Handbook are described, and thereafter, in Section 3.2, the current practice is analysed by presenting a questionnaire survey of reliability management in nine European TSOs. The focus of ENTSO-E rules is in the operational time frame while the questionnaire deals with short-term (system operation), mid-term (planning and asset management), and long-term (system development).

3.1 Mandatory rules

The current requirements on system security and procedures are specified in ENTSO-E Continental Europe Operation Handbook policies numbered from 1 to 8[1]. The details of the policies are dealt with in related appendixes. The handbook is a spot-on copy of the former UCTE[2] Handbook, which is in use in the largest synchronous system of ENTSO-E, the Continental synchronous system, until the new ENTSO-E codes are ready. At the moment the handbooks are under transformation and enhancement into the future ENTSO-E Network Codes described in further details in Chapter 4. The current requirements for system security are specified in ENTSO-E Continental Europe Handbook Policy 3 – Operational Security (ENTSO-E 2009c) and Policy 5 – Emergency Operations (ENTSO-E 2010a). In this section, the relevant parts when it comes to security management according to ENTSO-E policies, are selected and briefly presented.

According to the ENTSO-E handbook Policy 3 – System Security, all member TSOs shall implement the functionality specified. This policy specifies the requirements for operating the transmission system to maintain security. In the ENTSO-E rules, the principles for system security are based on the N-1 criterion.

According to Policy 3 (ENTSO-E 2009c)

> "Each control area – and TSO – is responsible of procedures for reliable operation over a reasonable future time period in view of real-time conditions and of their preparation. Therefore the N-1 principle has been developed with the goal for each TSO to prevent any propagation of a single incident with the meaning of "no cascading with impact outside my borders". The N-1 principle is then to prevent an emergency condition that appears as a result of a combination of events. Coordination between TSOs contributes to enhance the common solidarity and to cope with risks resulting from the operation of interconnected networks, to prevent disturbances, to provide assistance in the event of failures with a view to reducing their impact, and to provide resetting strategies after a collapse. This coordination is intensively developed covering today new aspects related to market mechanisms."

The exact procedures vary from one TSO to another. Additional information on such procedures is presented in 3.3.

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[1] Policy 1 (ENTSO-E 2009a, Policy 2 (ENTSO-E 2009b), Policy 3 (ENTSO-E 2009c), Policy 4 (ENTSO-E 2009d), Policy 5 (ENTSO-E 2010a), Policy 6 (ENTSO-E 2009e), Policy 7 (ENTSO-E 2009f), Policy 8 (ENTSO-E 2008)

[2] UCTE (The Union for the Co-ordination of Transmission of Electricity) coordinated the operation and development of the electricity transmission grid for the Continental European synchronously operated transmission grid before ENTSO-E started its operation in 2009.

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The second edition of Policy 3 focuses mainly on the N-1 criterion, which was at stake during the recent European events of 2003 (UCTE 2004) and 2006 (UCTE 2006). Both events were disturbances in normal conditions and affected the UCTE power system.

According to Policy 3 (ENTSO-E 2009c, p. P3-2) the in-depth definition of N-1 principle is based on:

- "the risk assessment considered by each TSO,
- the contingencies and their gravity in terms of consequences for the system to be considered in the security calculations whose goal is to detect constraints of network,
- the area to observe the system by each TSO in order to get the best survey of constraints to come,
- the operating limits accepted by TSOs with the minimum risks for the system,
- the remedial actions to cope with and relieve constraints in due time with simulations of their efficiency in advance,
- the strengthened coordination between TSOs to implement such stronger commitments."

The formulations above, stated in Policy 3, are vague and leave a lot of room for interpretations for the TSOs. Section 3.3 presents how European TSOs have implemented the N-1 criterion.

As Policy 3 only specifies requirements for normal operation, it is complemented by Policy 5 – Emergency Operation. Policy 5 investigates all abnormal and insecure operational situations that are not ruled in the Policy 3, mainly in emergency and blackout states with the restoration process. Policy 5 states:

> "Due to the fact that TSOs cannot ensure the security of operation irrespective of the conditions of operation of power plants and distribution networks, TSOs call for a regular coordination at the level of generation and distribution and for a sufficient performance of equipment connected to their grids with robustness to face normal or severe disturbances and to help to prevent or at least limit any large disturbance or to facilitate restoration of the system after the collapse." (ENTSO-E 2010a, page P5-1)

Regarding the objective of the use of the definitions of ENTSO-E Policy 3, listed above, the number of the system states in one of the ENTSO-E synchronous areas, ENTSO-E Regional Group Central Europe (ENTSO-E RG CE[3]) is related to four situations, presented in Figure 3.1. These are classified in relation with the grid or load/frequency risk levels and urgency of actions related to risks of propagation. The four stages are as follows:

[3] The Regional Group Continental Europe comprises the TSOs of the former UCTE synchronous area.

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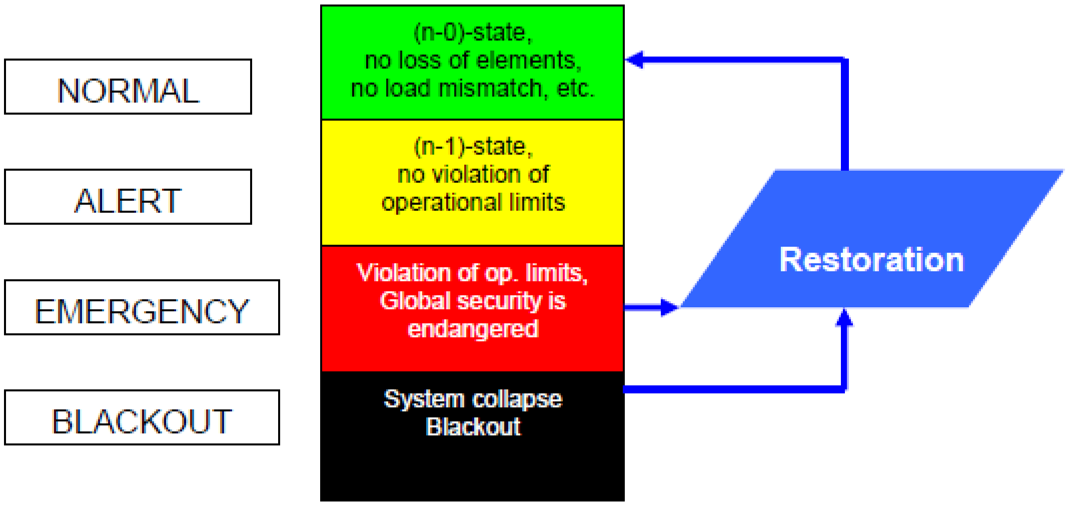

Figure 3-1: The system states of the ENTSO-E Regional Group Central Europe (ENTSO-E 2010a, p. 5-10)

According to ENTSO-E Policy 5 (ENTSO-E 2010a, p. 5-3), the definitions of the states are the following:

> ”**Normal:** No risk for interconnected system operation. All consumption and production are in balance and requirements on ancillary services and framework conditions are met; frequency, voltage and power flows are within their predefined and allowed limits (thresholds) and reserve (margins) are sufficient to withstand pre-defined contingencies. Operation is within normal limits, taking into account remedial actions effects.
>
> **Alert:** Risk for interconnected system operation. System within acceptable limits. TSO has uncertainties to come back to a normal state after one or more contingency.
>
> **Emergency:** Deteriorated situation (including a network split at a large scale). There is a higher risk for neighbouring systems. Security principles are not fulfilled. Global security is endangered. No guarantee of total efficiency of remedies to limit propagation to neighbouring systems or to the whole ENTSO-E Regional Group Central Europe system. From this state once stabilised it can be undertaken restoration of parts of the system (e.g. after load shedding or system split).
>
> **Blackout:** Characterised by the almost or total absence of voltage in the transmission system with consequences abroad and triggering TSOs restoration plans. A blackout can be partial (if a part of the system is affected) or total (if the whole system is collapsed). From this state, restoration is undertaken with stepwise reenergising and resynchronising of the power system.”

Appendix 3 for Operational Security (ENTSO-E 2009g) defines at a more detailed level how the N-1 criterion shall be executed.

Power system reliability is expressed in the Appendix 3 as the ability to:

- “ensure normal system operation;
- limit the number of incidents and avoid major incidents;

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- limit the consequences of major incidents whenever they do occur." (ENTSO-E 2009g, p. A3-1)

It is worth noting that the expression above by ENTSO-E is the practical interpretation of the reliability definitions given by IEC 60050 standard (IEC 2014) and the report prepared by IEEE and CIGRE working group (Kundur et al. 2004). The ENTSO-E interpretation permits an active approach to improving reliability. It encourages one to classify the unacceptable consequences of incidents, identify the initiating events and the mitigation measures limiting the relevant risks.

Appendix 3 (ENTSO-E 2009g, p. A3-1) also states that in order to ensure the safety of the system, protection must be provided against four main phenomena that may deeply disturb the system or initiate a large scale incident:

- cascade tripping
- voltage collapse
- frequency collapse
- loss of synchronism.

Appendix 3 for Operational Security provides as a main principle that the goal is "reliability, but not at any price" (ENTSO-E 2009g, p. A3-1). This statement indicates that some kind of risk assessment is needed to ensure that the reliability management costs not become too high. The following quotation from the appendix, which describes the rules to the TSOs in this context:

> "At all times, the system operator must do everything that is necessary to ensure that the system remains viable following a hypothetical contingency on the nominal situation leading to the loss of *k* facilities (substation, line, cable, transformer, load, generation unit, capacitor, reactor, coupling device). Depending on the type of contingency, the operator can nevertheless tolerate some risk according to a cost-reliability choice.
>
> For example, tripping of a generation unit is one of the most probable events in a network. It should therefore have the lowest consequences on the system. On the other hand, some events, such as the outage of a complete power plant with several units or the loss of a 400 kV substation with more than one busbar, cannot be taken into account due to exceeding dimensioning efforts on the system. Indeed, even if the cascading effect can be effective and the volume of power to be lost can be extremely high, the probability of those events is extremely low.
>
> The TSO must cope with the most probable events by dimensioning its system and defining margins. For rarer events or combinations of events respectively, the TSO may allow a degradation of the system operation, but nevertheless try to limit the consequences (for example by using automatic load shedding)." (ENTSO-E 2009g, p. A3-2)

Appendix 3 (ENTSO-E 2009g) also discusses risks and gives equations for calculating risks:

> "Considering the operation of a power system from the point of view of risk management, implies the definition of a risk level that should be respected for any kind of events. This risk level is assessed by a reference value of the product "Event probability × Expected loss". The greater the probability of an event occurrence is, the lower is the accepted loss. The loss may be defined either by a financial loss or more commonly for a power system in terms of potential power interrupted or energy not supplied.

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The following formula quantifies the risk associated to the event i:

$$R_i = P_i \times S_i$$

where

$$S_i = G_i \times D_i$$

and

- R_i : Risk associated to the event *I,*
- P_i : likelihood of the event *i* for a given unit of time (hour),
- S_i: Severity associated to the event *i*, expressed in terms of energy not supplied. The severity is the multiplication of the Gravity (G_i) and the restoration time (D_i),
- G_i: Gravity associated to the event *i* = violation of the operational criteria expressed in power interrupted (MW), and
- D_i: restoration time associated to the event *i* = time needed to restore the full load if the event takes place.

As this risk is given for a unit of time, one can define a mean risk per day by introducing a frequency of exposure. The risk is then defined as:

$$R_i = P_i \times S_i \times f_i$$

where f_i is the frequency of exposure associated to the event *i*, percentage of the period of analysis where the event will lead to the evaluated severity.

As the above definition of the risk is based on the energy not supplied, it is also possible to determine the cost of this risk:

$$C_i = R_i \times c_{ENS}$$

where

- C_i = cost of the risk,
- R_i = risk as defined above,
- c_{ENS} = estimated cost of the energy not supplied.

Based on these definitions, the optimization of the corresponding operational grid situation by looking for the best quality/continuity of the provided services at the best 'cost plus penalties'[4] ratio will lead the TSO to take into consideration all remedial actions having a total effective cost lower than the cost of the risk.” (ENTSO-E 2009g))

The quotation above is yet again quite vague. Here, the TSO’s are urged to use some kind of risk assessment, but it is very much up to each TSO how to do it. This illustrates clearly the need for more

[4] This is an example of an unclear formulation in the operational handbook. The 'costs + penalties' together can be interpreted as the expected total impact of a given situation. It is high either when the quality is very low or when it is very high and has a minimum value (optimum) somewhere between. The costs are the expenses generated in order to increase the quality, they reflect the contracted costs such as human resources, tools or preventive actions. The penalties are non-contracted expenses due to a decrease of quality and/or of continuity of the service. The penalties are high when the quality is low but they decrease as the quality increases. (ENTSO-E 2009g, Figure 1 on page A3-1).

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concrete and concise formulation of common rules, which is one of the main purposes of the coming ENTSO-E network codes described in Chapter 4.

3.2 Current TSO practices for reliability management

3.2.1 Introduction

The following sections summarize the results of a questionnaire sent to European TSOs in 2014. The questionnaire (in Appendix 1) was answered by 9 TSOs from Northern, Eastern and Central Europe.

The questionnaire was prepared to provide information about the status of reliability management in practice and the views of TSOs regarding:

- Current reliability management approaches (N-1 criterion etc.)
- Reliability methods, tools and data (including socio-economic impact)
- Drivers and barriers for new reliability standards
- The functional description of necessary methods and data for new reliability standards.

The results on the reliability methods, tools and data are reported in the first deliverable D1.1 of WP1 (GARPUR Consortium 2014).

Most of the TSOs that provided answers to the questionnaire have a system where almost 100 % of the lines on the highest voltage levels (220 kV and above) are overhead lines. Some of the TSOs have only single lines and other have only double lines, and a third group has a 50/50 split between single and double lines. 20 % of the lines of one of the TSOs are underground cables.

Among the respondents there is a mix of large and small TSOs. The large TSOs typically never have an intact grid to operate, while in the smaller TSOs' control area there is typically around 50/50 split between intact and non-intact grid. In the smaller TSOs, the grid is mainly intact in winter, and there are typically planned outages during summer.

3.2.2 Definitions of N-1 and N-2 criteria

In the first two questions, the TSOs were asked to give their definition of the N-1 and N-2 criteria, respectively. A typical definition of N-1 is that each TSO has a contingency list consisting of the failure of single lines and in most cases also transformers and generators and no differences between the time horizons. If there is a failure of one of the elements in this list, the system should be able to cope with it without loss of load or violating any operating constraints. The definition of N-2 is similar, including simultaneous failure of two elements on the contingency list. However, most TSOs mentioned that this criterion is not used.

There are some exceptions from this general observation. For instance, not all TSOs have the strict interpretation that no loss of load is accepted, but have a certain limit to the loss of load that is accepted in the case of a failure. And even though none of the asked TSOs actually uses the N-2 criterion, some TSOs include parallel line faults in their contingency list.

Six out of nine TSOs state that – during operation – after a fault the system should return to the same state as before the fault after *x* minutes (*x* being typically 15). Two of the TSOs actually have included this aspect in their planning criteria as well. However, as one of them states, it is difficult to model all possible preventive actions that could be used in such a case, so instead – in the criterion – a minor loss of load is accepted after the second fault. One of these TSOs calls this an "N-1-1 criterion" while another calls it a "consecutive N-2" criterion.

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Additionally, the TSOs were asked whether the N-1 definition changes during planned outages. Typically, this is not the case, but the amount of lost load that is accepted by some TSOs is slightly increased.

3.2.3 Overall practice regarding N-1

As already mentioned, all the nine TSOs are practicing the N-1 criterion in some way or the other. Most TSOs answer that they follow the N-1 criterion strictly or even stricter (like the N-1-1 criterion mentioned above), however there are a couple of TSOs that have a relaxed version, where limited consequences in the form of loss of load are accepted.

The TSOs change their practice as the operational situation changes. A common example is that adverse weather conditions make the TSO more alert, and the N-1 interpretation strengthens. One of the TSOs, for instance, does not include the trips of double lines as a contingency under normal conditions but when there is a storm, a double-line trip is considered as an N-1 fault. In total, 7 out of 9 TSOs answer that they sometimes use either weaker or stronger criteria than the strict N-1.

When there is a planned outage in the grid, the TSOs generally follow the same N-1 criterion as above. Some of the TSOs take planning measures such as reduced import/export capacities in order to ensure that there will be no consequence of an outage, while others relax the criterion and accept higher consequences after outages. Two TSOs answered that they switch from N-1 to N-0 security during planned outages.

The TSOs were asked whether the reliability criterion changes with the geographical area. Three out of nine TSOs answer that they have stronger reliability criteria for e.g., major cities, sites such as business districts or special events with crucial importance to society.

3.2.4 Detailed answers

The TSOs were asked what kind of faults they include in the contingency list according to the N-1 criterion. Figure 3.2 shows the answers from the TSOs.

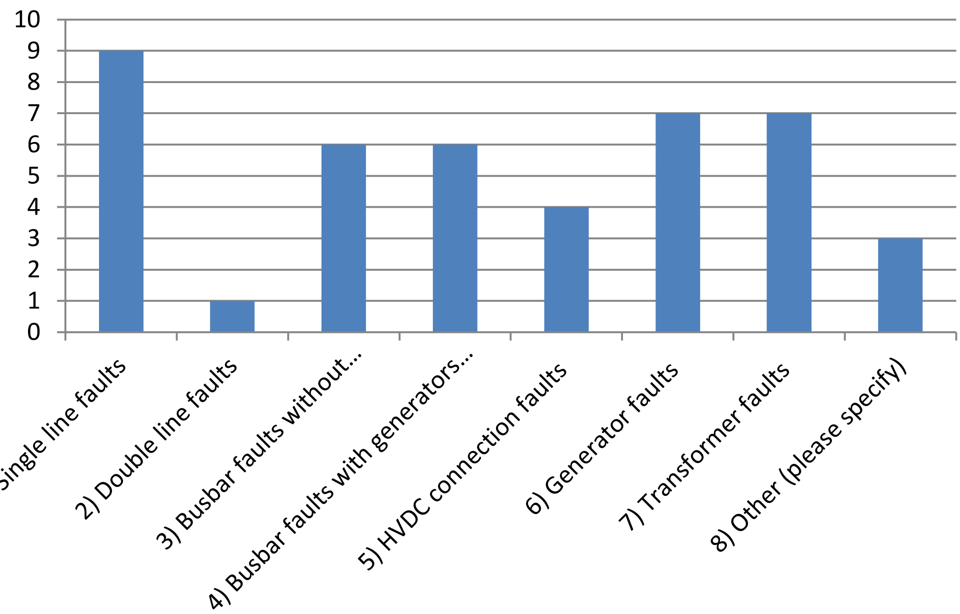

Figure 3-2: Answers to Q7 "What kind of faults are included in the N-1 criterion as N-1 faults?"

The figure shows that there are quite many similarities among the TSOs and that most of the fault types specified are actually used. The clearest exception is double line faults, which are only used by one of the TSOs. The other outage types that are mentioned by the TSOs are the auxiliary supply to HVDC systems, demand loss, capacitor bank fault, and coupling of busbars, SVC and other reactive power devices.

The TSOs were asked whether a double line failure is considered to be an N-1 fault (a double line fault is e.g., trip of two lines that are on the same tower, or two cables that are in the same ditch). Seven out of nine TSOs answered that they only consider single line faults, while one TSO considers a double fault as an N-1 fault for the intact grid. Two of the TSOs include the double line fault in the contingency list in extreme weather conditions.

Further, the TSOs were asked about the major limiting factors after an N-1 fault. Figure 3.3 shows the answers.

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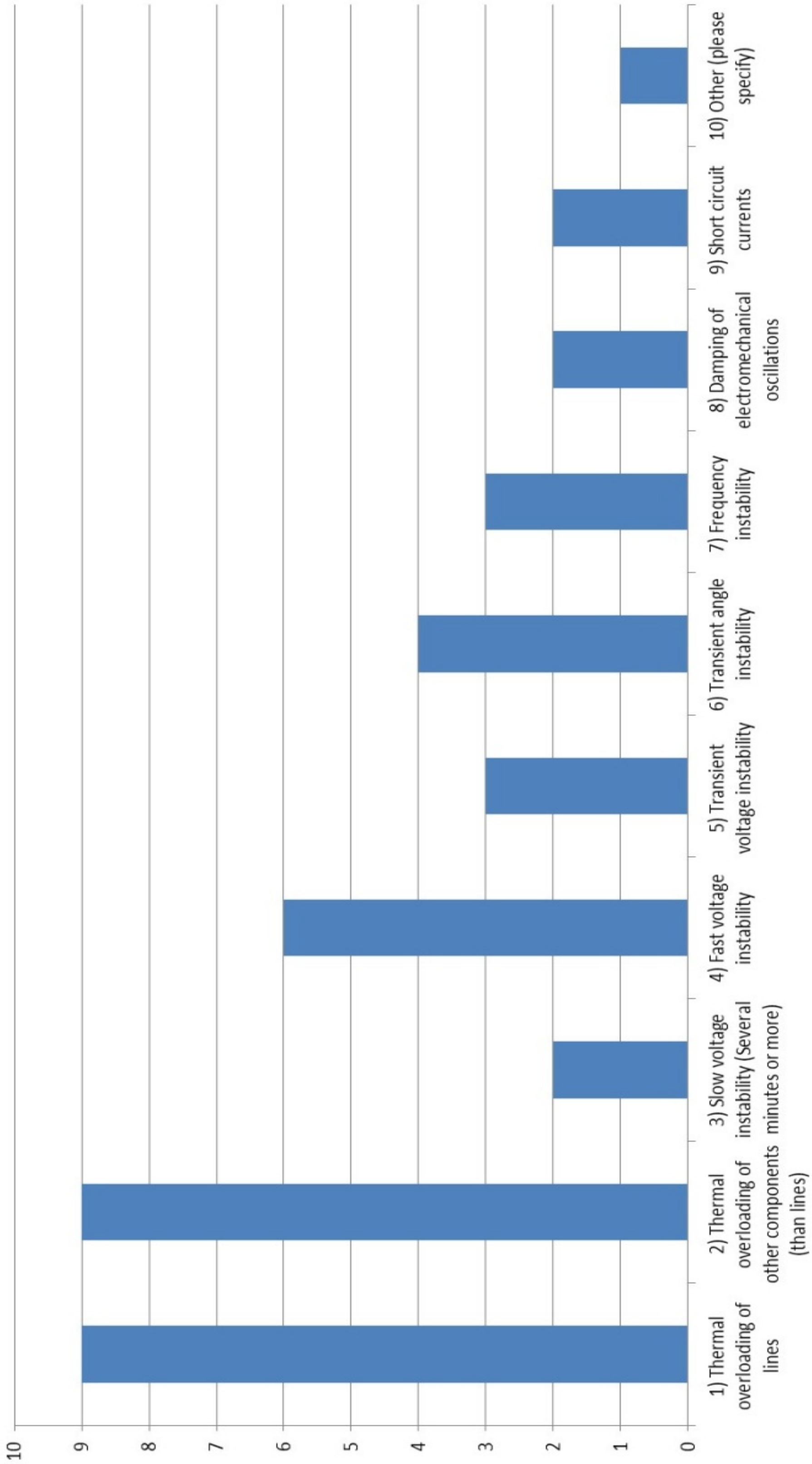

Figure 3-3: Answers to Q9: "Which limiting factors after N-1 faults in the intact grid set the limits for the transmission capacity?"

The figure shows that there are quite large differences among the TSOs regarding this question. All TSOs consider thermal overloading of lines and other components as a limiting factor, while six out of nine also responded fast voltage instability. The other answer alternatives are only chosen by a small number of the TSOs and this is probably due to the characteristics of their respective systems. An extra limiting factor mentioned by one of the TSOs is the voltage level itself. An interesting observation that can be made from the answers is that only two TSOs consider thermal overloading to be the only limiting factor after an N-1 fault.

The TSOs were asked when the N-1 they abandon the N-1 criterion. The answers are shown in Figure 3.4. Even though a majority of the TSOs answered that they follow the N-1 criterion strictly, there are cases, where they regard the N-1 criterion to be insufficient or too restrictive.

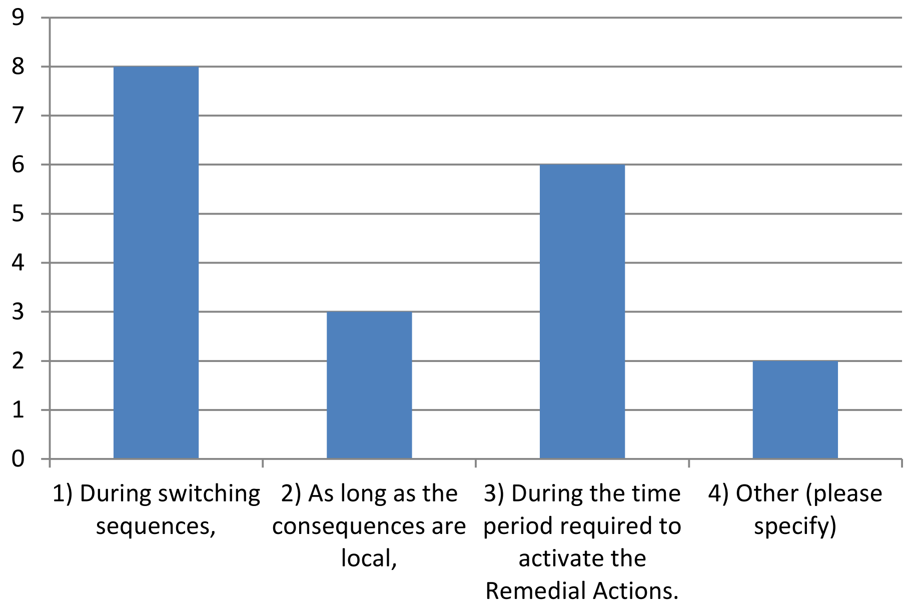

Figure 3-4: Answers to Q10: "In which cases are N-1 not fulfilled in your system?"

One of the TSOs replied that the N-1 criterion is never completely fulfilled in their system. For eight of the TSOs the N-1 criterion is not fulfilled during switching sequences. Six of the nine TSOs do not follow N-1 during the time required to activate remedial actions. Three TSOs answered that they accept local consequences of faults, while one TSO stated that it doesn't follow the N-1 criterion at 110 and 150 kV levels.

Further along this line the TSOs were asked whether they find cases where the N-1 criterion is insufficient. Seven out of nine TSOs confirmed this. The most common cases are severe weather conditions and cases where there are long repair times. There is a big difference between the TSOs in this respect. Two of the TSOs think that N-1 is too conservative in general, while the others think that N-1 is fine in general, but too loose under severe weather conditions. Last, one of the TSOs said that N-1 is too loose in general, and so applies an N-1-1 criterion, as explained in Section 3.3.2.
The TSOs were asked to indicate what they do when N-1 is insufficient. Some TSOs perform N-2 calculations under stormy weather, while others have specific double outages in their contingency list. Some keep spare parts in the case of long repair times, while others work on shortening the potentially long repair times.

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3.2.5 Sometimes using the N-0 criterion

The TSOs were asked whether they sometimes use the N-0-criterion. The questionnaire defined the N-0 criterion as follows:

"By using the N-1 criterion, the consequences after a single fault are regarded acceptable. In the following question we investigate cases where this is too restrictive. Please interpret "using the N-0 criterion" as accepting more severe consequences after certain faults."

Following this definition, six out of nine TSOs claimed that they sometimes use the N-0 criterion. In the following, it is investigated in detail when and why more severe post-fault consequences are regarded as acceptable.

The TSO's were asked when they use the N-0 criterion. The answers are given in Figure 3.5.

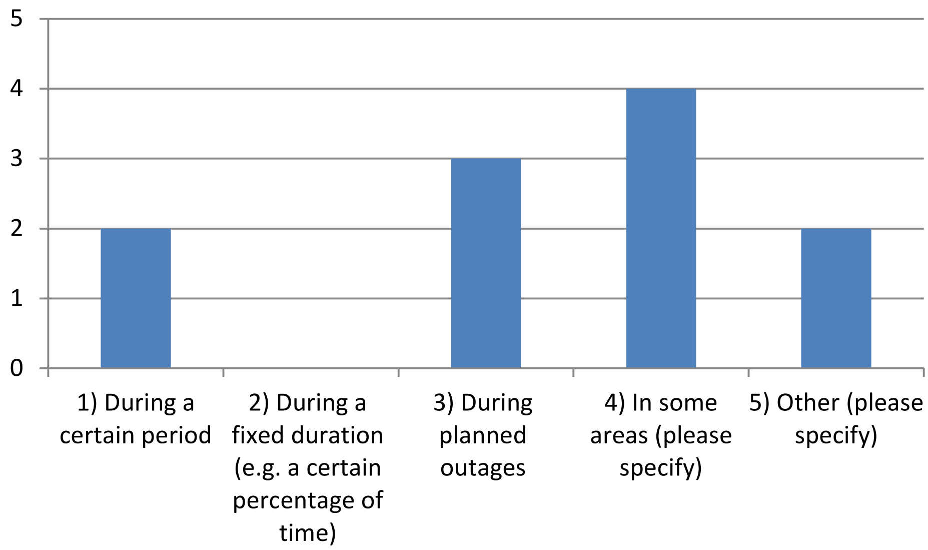

Figure 3-5: Answers to Q19: "When do you use the N-0 criterion?"

From Figure 3-5 it can be seen that N-0 is used both in certain periods and in certain areas. Four out of the six TSOs sometimes use N-0 criterion when the consequences are local. Four TSOs take the ambient situation into consideration when using the N-0 criterion. The TSOs were also asked why the N-0 criterion is used. The answers are shown in Figure 3.6.

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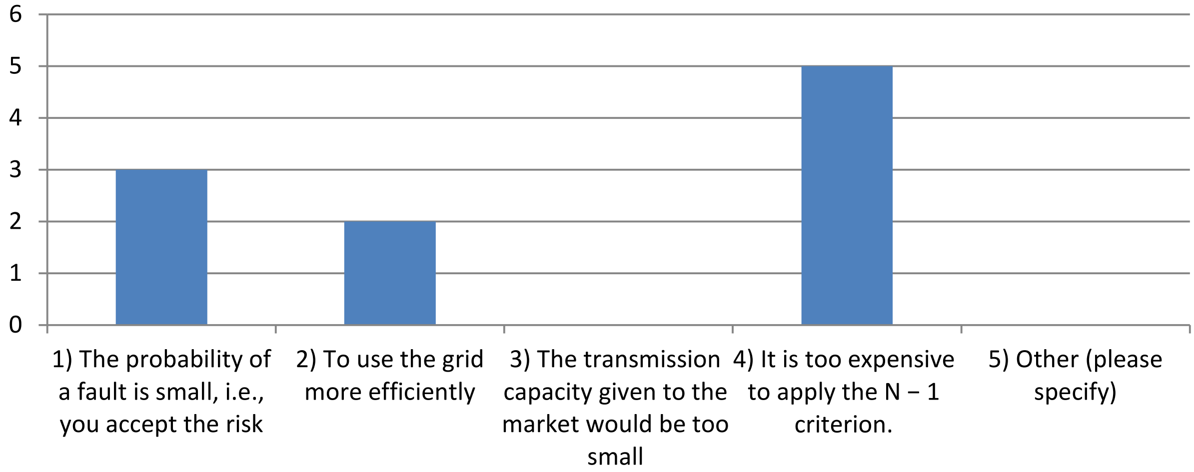

Figure 3-6: Answers to Q19a: "Why do you use the N-0 criterion?"

The figure shows that five of the six agree that applying the N-1 criterion is sometimes too expensive. Three TSOs accept more severe consequences of failures with low probabilities, while two TSOs sometimes use N-0 in order to use their grids more efficiently.

Further, the TSOs were asked under which situations the N-0 criterion is acceptable. The answers are shown in Figure 3.7.

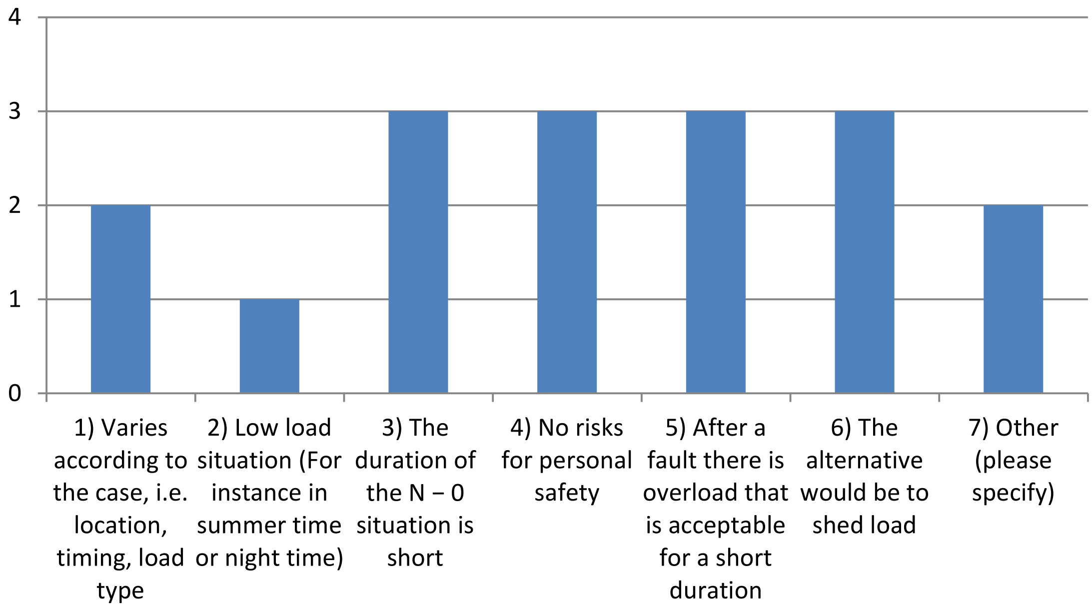

Figure 3-7: Answers to Q19d: "Which are the acceptable situations when you apply the N-0 criterion?"

The figure shows that there is a variation among the TSOs on this point. Alternatives 2-5 represent situations with minor consequences of different sorts. This indicates that the TSOs accept N-0 situations when consequences are small. Three TSOs answer that they rather accept N-0 than shed load beforehand. Another acceptable situation mentioned, is the case where consequences are local.

The TSOs were also asked how the probability of faults is evaluated when using N-0. Four TSOs answer that it varies according to case, without really commenting on how. One TSO uses the same statistics in

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all situations, while another uses different probabilities based on weather forecast, load conditions, time of day, location etc. One of the TSOs does not calculate the probabilities but uses N-0 when there is no other way to ensure N-1.

Finally, the TSOs were asked what consequences can be accepted after a fault. The answers are shown in Figure 3.8.

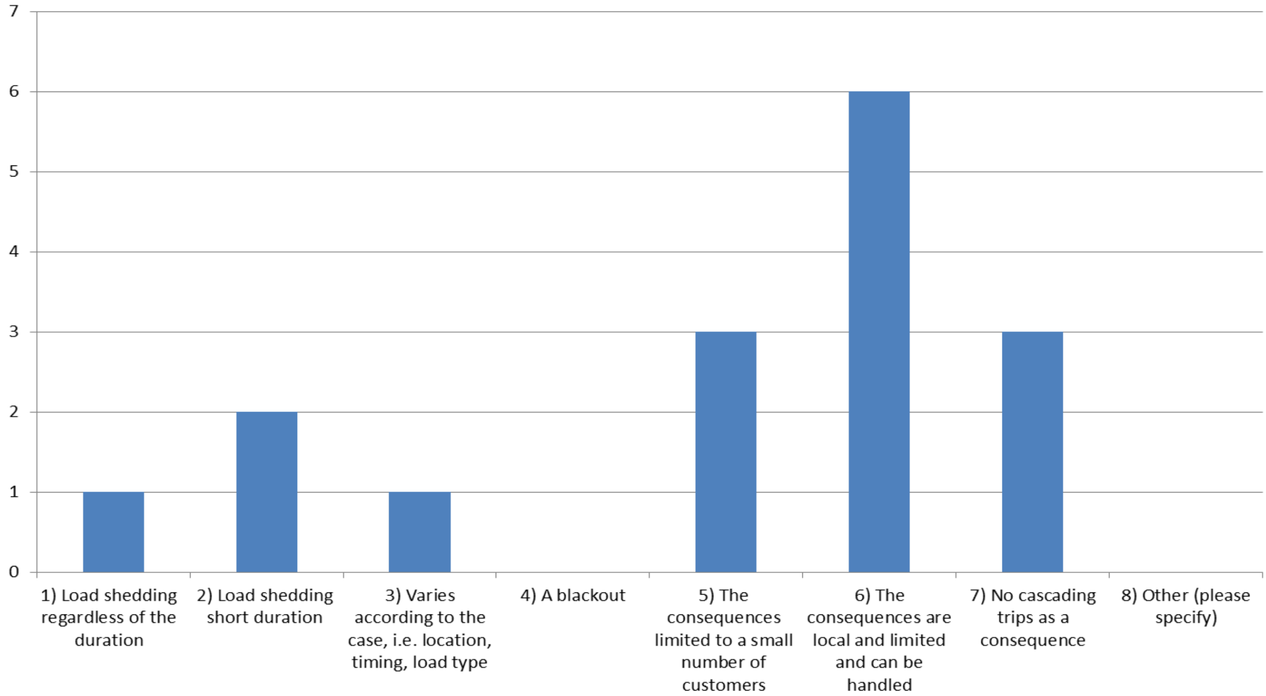

Figure 3-8: Answers to Q19f: "Which are the acceptable consequences when you apply the N-0 criterion and there is a fault?"

Figure 3.8 shows that six TSOs share the opinion that local and limited consequences are acceptable. Three TSOs accept consequences where the number of affected customers is small, and also consequences that do not imply cascading trips. Only two TSOs think that load shedding is an acceptable consequence after faults in the system.

3.2.6 Repair times and probabilities

The TSOs were asked whether they use varying repair times in their consequence evaluations. Six out of nine TSOs replied that they do. Two of the TSOs wrote that they are forced to compensate customers for consequences of long repair times. Two other TSOs noted that they have spare components where repair times are long.

Further, the TSOs were asked if they include probability considerations in combination with their N-1 analyses. Three out of nine TSOs do. The typical way this is done is that rare faults, such as current transformer faults are ignored and left out of the contingency list. Only one of the TSOs actually uses grid fault statistics. However, it should be noted that answers to some of the other questions indicate that there is an understanding that extreme weather increases the probability of overhead line faults and hence, these situations are treated differently.

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3.2.7 Time horizon differences

The N-1 criterion is used both in short-term (system operation), mid-term (planning and asset management) and long-term (system development) of transmission grids. This way there is coherence across time horizons in the current reliability management scheme. However, there are some differences in the needs and practices between the time horizons. Figure 3.9 shows the answers to the TSOs practices for different time horizons.

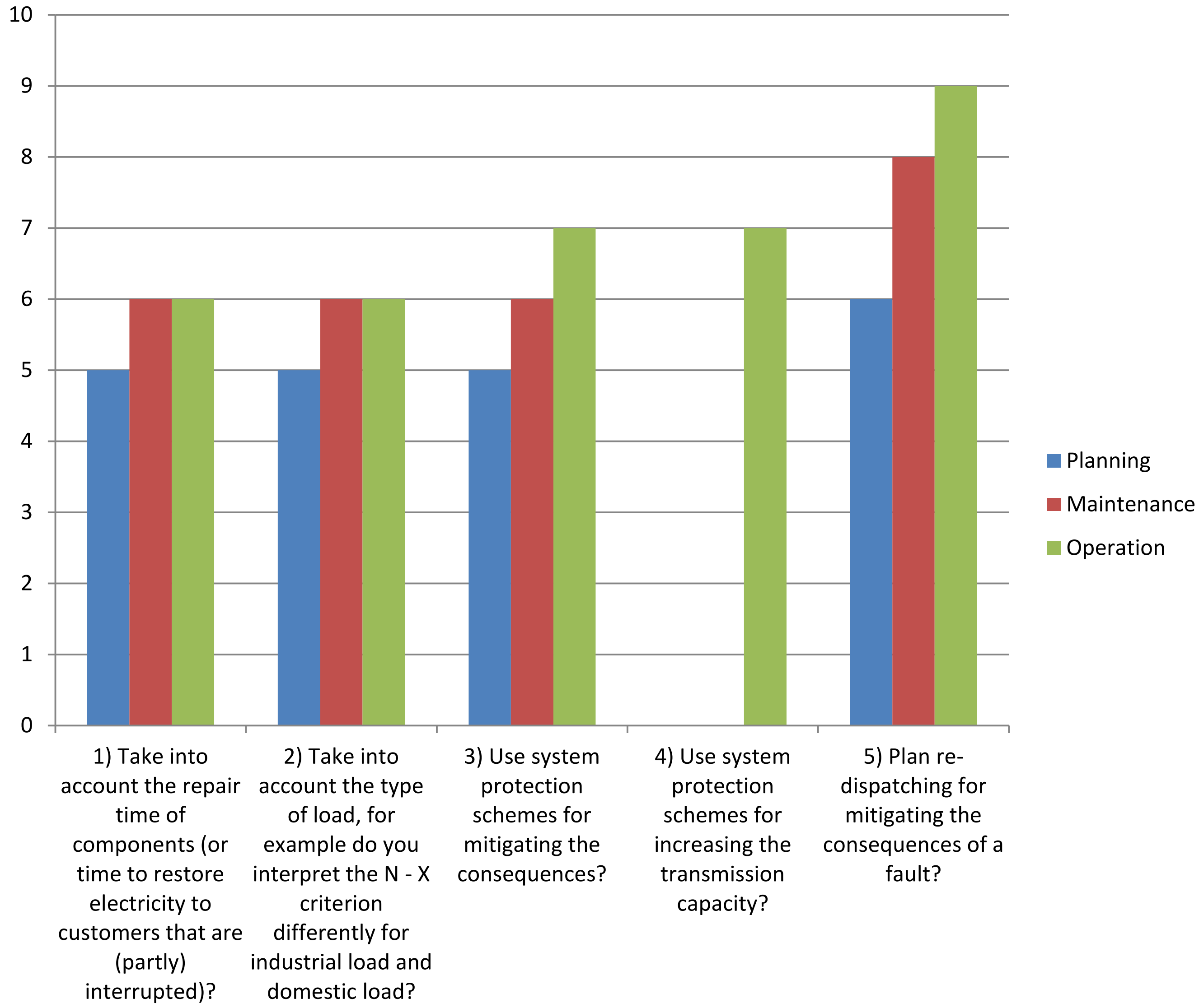

Figure 3-9: Answers to the questions Q20–Q22: "When planning the grid / operating the grid/ operating the grid during maintenance work, do you…?"

Figure 9 shows that the answers differ slightly between the time horizons. Generally TSOs take more aspects into account during operations than the longer time horizons. All TSOs plan re-dispatching for consequence mitigation in the operational time frame while only six TSOs take this aspect into account in the planning horizon. In the operational time horizon, seven TSOs use system protection schemes for both mitigating consequences and increasing the transmission capacity. (The increasing capacity alternative was only available in the operational time frame question). Six TSOs take repair time of

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components into account and the same number of TSOs takes into account the type of load that might be interrupted.

The state of the art regarding methodologies for reliability assessment both in literature and in TSO practice are described in D1.1 of the GARPUR project (GARPUR Consortium 2014), showing that the methodologies in use differ between the different time horizons. According to the questionnaire, 6 of the TSOs reported that they use probabilistic reliability methods for long-term planning, while in short-term operation mainly power flow and dynamic analyses are used. This is shown in Figure 3-10.

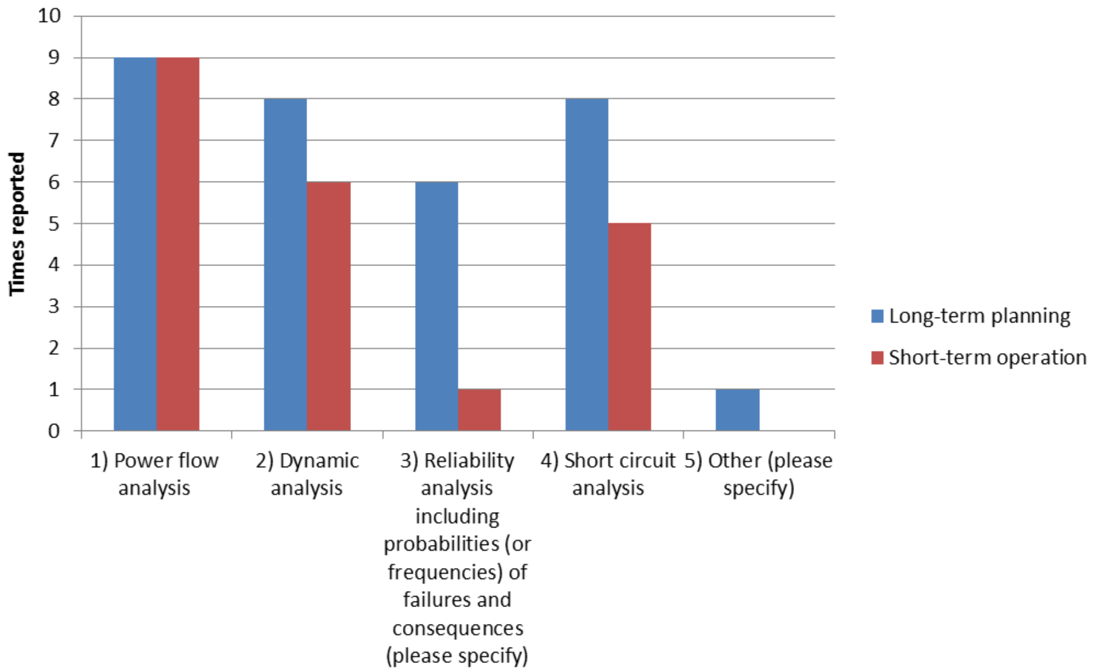

Figure 3-10: Answers to the questions Q24-Q25: "Which methods are used to assess the reliability of planned grid developments/ the operational reliability"

For asset management, the answers revealed that methods like Reliability Centred Maintenance (RCM), Failure Mode and Effect Analysis (FMEA) and Markov models are used. Important aspects reported are consideration of age of the components and the impact of asset management on system reliability (GARPUR Consortium 2014). The questionnaire also showed that all the TSOs collect fault statistics (particularly failure frequency) for the major components and that these data are used both for planning and asset management purposes (GARPUR Consortium 2014).

3.2.8 Socio-economic benefits and costs

The TSOs were asked how they include socio-economic benefits and costs in the reliability management of the transmission system today. Differences between the time horizons were not explicitly asked, however one TSO stated some differences, such as congestion management costs and reactive reserves costs in the operation but social welfare in the planning. The answers are summarized in Figure 3.10.

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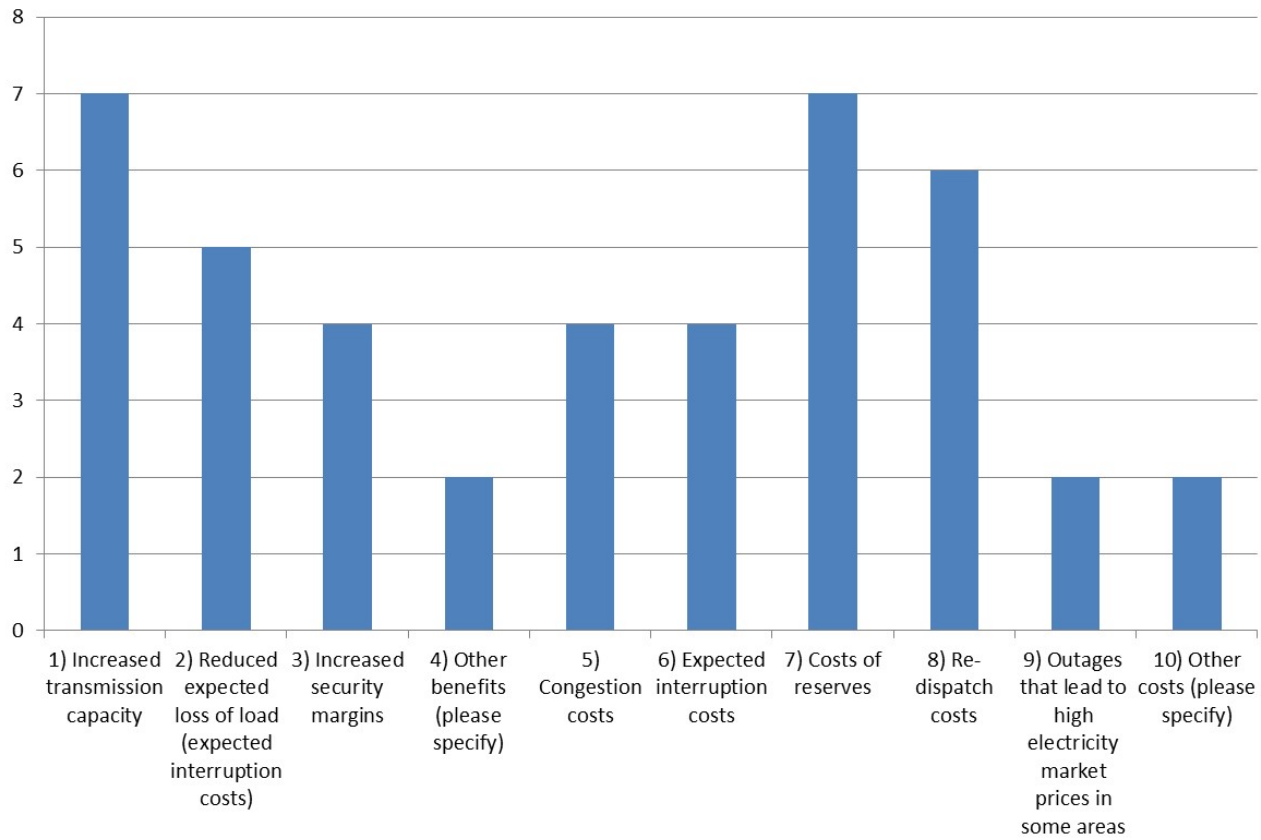

Figure 3-11: Answers to the question (Q 23) where the TSOs were asked what kind of socio-economic benefits and costs are included in analysing their transmission system today

The figure shows differences between the TSOs. Though it can be seen that most TSOs focus on increased transmission capacity and the costs of reserves as benefits, the other benefits are more spread among the TSOs. Re-dispatch costs are viewed as important socio economic costs by the TSOs. Social welfare from market integration and CAPEX of investments are mentioned among other benefits/costs.

3.2.9 General comments of the current European practices

The questionnaire survey indicates that there is quite a common understanding and definition of the N-1 criterion: The power system shall withstand the fault and outage of any single component that is included in a predefined list of contingencies. There are different interpretations as to what exactly 'withstand' means, and what should be included in the list of contingencies.

All the TSOs in the questionnaire base their reliability management on the N-1 criterion, and most TSOs claim that they follow it strictly. Some have weaker criteria, and others have stronger criteria in certain situations. The detailed questions reveal that all TSOs have exceptions and adjustments to the general criteria that are probably inspired by the special characteristics of their systems and their experiences when planning and operating them.

N-1 is a deterministic reliability criterion. In a strict interpretation of it, the probabilities of contingencies do not need to be considered, only the consequences. The survey reveals that, in line with this, the TSOs seldom use probabilities in their reliability management. However, there are some tendencies, such as the TSOs' awareness of higher failure probabilities in extreme weather conditions and the exclusion of very rare faults from some TSOs' contingency lists.

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The general impression is that the current reliability management is coherent between time horizons (planning, maintenance and operation) but, not surprisingly, more aspects and details are considered in the operational time frame than in mid-term and long-term planning time frames.

3.3 Practices in multi-area and multi-agent environment

The European interconnected power system is a multi-area power system operated by several TSOs. Section 3.1 and Chapter 4 describe the current and coming rules for operating this system, where TSOs are mainly responsible for reliability of their own control area, and a need for coordination is pointed out but neither demanded nor concretely specified. The TSOs should also ensure that no cascades propagate to the neighbouring control areas as specified in Operation Handbook of ENTSO-E (ENTSO-E 2009b). However, actions performed and decisions taken by a TSO may have a significant effect on neighbouring control areas and therefore coordination among TSOs is required as noticed also in the Roundtable of European energy industrialists (Statnett 2014). Regarding data exchange there are requirements that are legally binding. Such legally binding requirements are presented in the Nordic grid code (Nordel 2007) and the Network code on operational security of ENTSO-E (ENTSO-E 2013b) because it has to be adopted in legislation of member countries. In the following, present European practices for long-term and operational planning time frames are briefly presented.

In the long-term planning horizon, the European coordination is done within the working group "Ten-Year Network Development Plan" (TYNDP) of ENTSO-E. The task of the working group is to lead the development and bi-annually publish an updated ten-year network development plan. The aim of the TYNDP is to increase information and transparency about investments required in the pan-European power system to help and support decision-making processes. It also serves as a basis for selecting candidate investment projects to the European Commission PCI (project of common interest) list. The latest published plan in June 2014 is the 2012 TYNDP. (ENTSO-E 2012)

In the short-term planning horizon, there are two main initiatives for coordination in Europe: Coreso and TSC (TSO Security Cooperation). The Coreso project uses a centralized approach whereas the TSC project has a decentralized approach. As these activities support planning and final actions are done by individual TSOs, these initiatives do not have operational activities.

Coreso has five TSO members. The activities of Coreso cover supporting activities for different time horizons (2 days ahead, day ahead and intraday and close to real-time). Coreso supports also TSOs in the event of a major disruption as the Coreso has a wide vision and understanding across Europe due to the merging of data for the whole Continental Europe. Furthermore, Coreso does coordination with the Great Britain synchronous area in project planning and in operational time frames. Besides, Coreso is involved in projects aiming at improvements for security of supply in Europe and offers training for operators. (Coreso 2014)

The TSC project has 12 TSO members. The TSC project provides an IT-platform for data exchange and N-1 security assessment. The data sets of individual TSOs are collected and merged. The IT-platform performs security calculations and offers an access to the results for the members of the TSC project. Experts of the TSO members analyse the results and decide the actions to be taken in collaboration. Finally, the individual TSOs implement the actions planned. (TSC 2014)

In addition to the horizontal data exchange between TSOs, data exchange and coordination vertically is also required, especially as the users connected to the transmission and distribution grids are expected to become more active in the future.

The present practice is that the DSO shall provide to its TSO the following structural information and update this information periodically at least every six months (ENTSO-E 2013b):

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- Substations and the voltage level;
- lines that connect the substations;
- transformers from the substations;
- significant grid users;
- reactors and capacitors connected to the substations.

Each DSO has to provide also data regarding type A generation[5] as defined in the network code on requirements for grid connection applicable to all generators. The data consists of the total aggregated generating capacity and related information concerning their frequency behaviour (ENTSO-E 2013b).

3.4 Reporting disturbances

As described in the first deliverable (GARPUR Consortium 2014 p. 22) from this work package, Nordic TSOs have published grid disturbance statistics for a long time. The statistics as of 1999 are available at the ENTSO-E web pages[6]. The older reports are in Scandinavian languages[7] but as of 2006 the reports are written in English[8].

Reports of this kind requires common guidelines, otherwise the numbers provided may not be coherent and do not represent the same issues. The guidelines for the Nordic report (Nordel 2009) provide detailed descriptions of how different incidents are classified. The reports provide statistics of disturbances, faults on power system components, failure causes and energy not supplied. These kinds of data may be useful for other TSOs as well, even though when using data from other geographical areas and other systems one has to bear in mind that e.g., faults caused by weather may have different frequencies in different areas and that the power systems have different characteristics. Moreover, the average ages of components and maintenance policies affect the failures, so a specific report cannot be valid for all circumstances.

Indeed, the statistics can reveal the reliability performance of a power system. For example, the 2012 Nordic statistics (ENTSO-E RGN 2013a, Table 4.2) present the energy not supplied in relation to the total consumption of energy in the Nordic countries. The 10-year averages (for the period 2003 - 2012) of the energy not supplied divided by the energy consumed in each country in the Nordic synchronous system, vary between (3.6–24.3) parts per million[9], which can be regarded to be a satisfactory performance. (It is worth noting that these values do not represent the total energy not supplied an each country, just the part due to transmission system faults and disturbances.)

3.5 Summary

ENTSO-E's Continental Europe Operation Handbook and especially its Policy 3 (ENTSO-E 2009c) specify the current rules for power system reliability. The handbook is a copy of the former UCTE handbook. The operational security is based on the N-1 principle, which is a deterministic principle.

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[5] "A power generating module is of type A if its connection point is below 110 kV and its maximum capacity is 0.8 kW or more" (ENTSO-E 2013e).

[6] https://www.entsoe.eu/publications/system-operations-reports/nordic/Pages/default.aspx

[7] (Nordel 1999, Nordel 2000, Nordel 2001, Nordel 2002, Nordel 2003, Nordel 2004, Nordel 2005)

[8] (Nordel 2006, Nordel 2007, Nordel 2008, ENTSO-E RGN 2009, ENTSO-E RGN 2011, ENTSO-E RGN 2013b, ENTSO-E RGN 2013a)

[9] Parts per million: x 10−6 MWh/MWh

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

The questionnaire shows that each of the nine respondents conscientiously has implemented the N-1 security principle as specified in the ENTSO-E Policy 3 and adapted it to local conditions. The principle is being used with minor differences for both planning, maintenance and operation.

TSOs have analysed disturbances carefully in order to understand causes and possible remedies. As a result, the N-1 principle has continuously been updated with new requirements for grid planning and operation. The complexity of the rules and the number of contingencies to be taken into account has increased accordingly. The outcome is a satisfactory reliability level, as at least can be seen in the public Nordic performance statistics.

The research leading to these results has received funding from the European Union
Seventh Framework Programme under Grant Agreement No 608540.

4 ENTSO-E NETWORK CODES UNDER PREPARATION

The European Commission has initiated ENTSO-E's preparation of new network codes. The network codes shall be developed for system operation, system development, cross-border network issues and market integration issues and shall be without prejudice to the Member States' right to establish national codes, which do not affect cross-border trade.

4.1 Network codes on operational security, planning and scheduling

This section presents an overview of the contents and status of the new proposed network codes, with focus on the Operational Security Network Code and the Operational Planning & Scheduling Network Code. The assortment of the ENTSO-E Network Codes is grouped in three main categories addressing the various actors involved and/or connected to the transmission network as depicted in Figure 4.1 below. More detailed description and motivation for introduction of the ENTSO-E Network Codes can be found on the ENTSO-E web site[10].

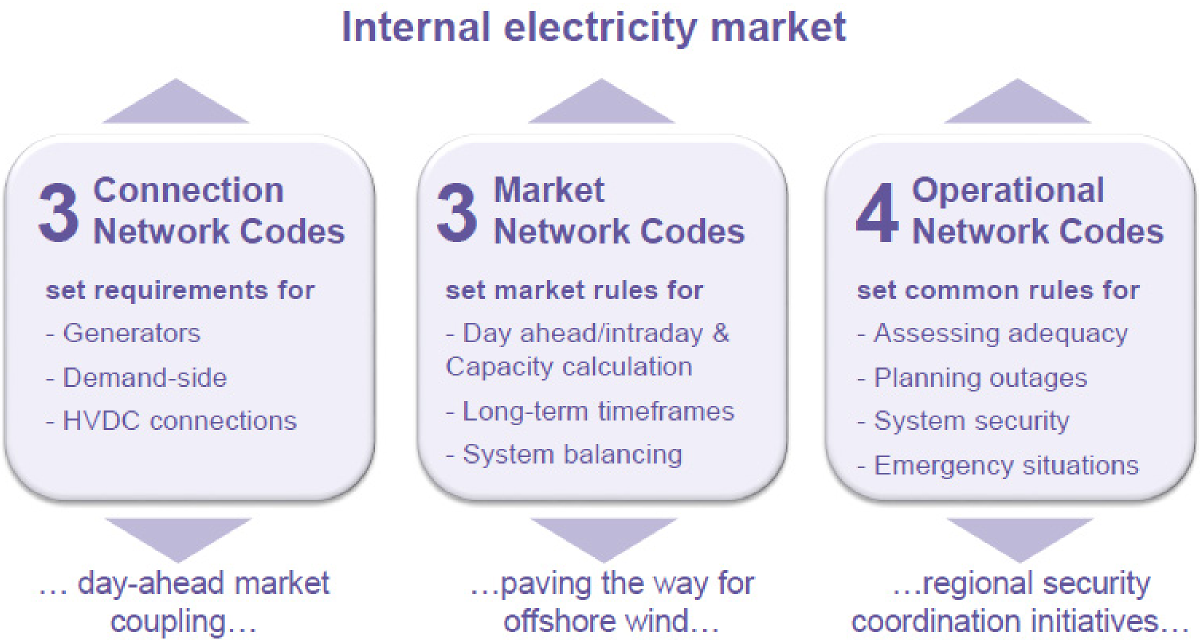

Figure 4-1: An overview of ENTSO-E Network Codes (ENTSO-E 2014b)

The actual status (April 2014) of the various network codes is depicted in Figure 4.2. The figure shows that the network codes for operational security, planning and scheduling are halfway in the approval phase. There are still some steps to go before entry into force. (ENTSO-E 2014b)

[10] Reference: https://www.entsoe.eu/major-projects/network-code-development/

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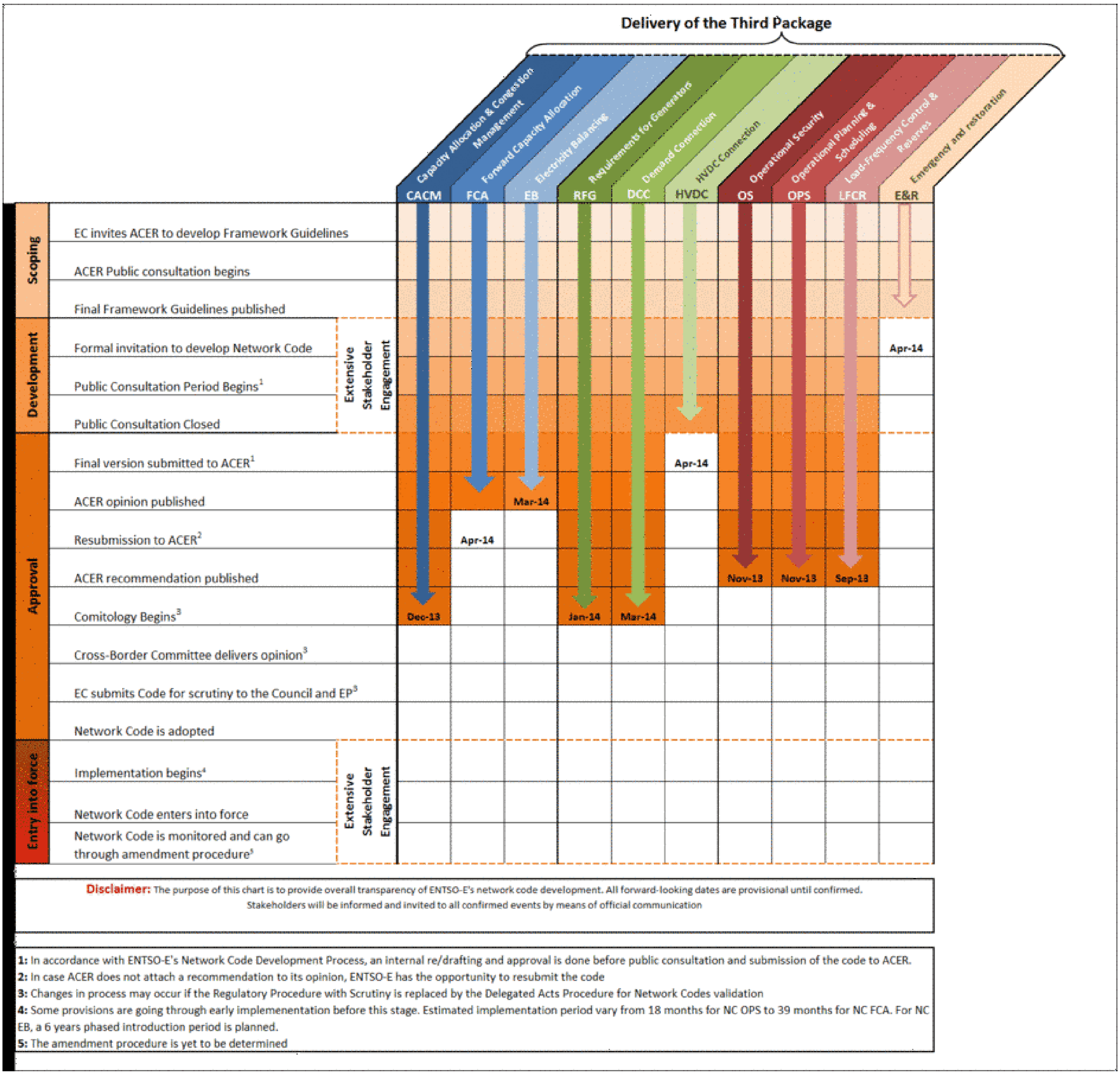

Figure 4-2: Status for the development of ENTSO-E Network codes in April 2014[11]

The proposed new network codes addressing system security and specifying the requirements for calculating the electrical network stability status applying the N-1 criterion are:

- Network Code on Operational Security (OS) (ENTSO-E 2013b)
- Network Code on Operational Planning and Scheduling (OPS) (ENTSO-E 2013d).

Based on the fact that the network codes on operational security and on operational planning and scheduling still are under development, the final outcome is difficult to estimate. Nevertheless, especially

[11] Retrieved on 13 May 2014 from https://www.entsoe.eu/major-projects/network-code-development/latest-updates-milestones/

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

the N-1 criterion seems to be well accepted and is estimated to survive the final committee procedure (comitology) of the evolutionary process.

Compared to the description of the current situation in section 3.1, the proposed OS and OPS network codes are more or less a rephrasing and a textual reorganization of the former UCTE Handbook Policy 3 and 5 and are as such, quite well in line with the current practice within ENTSO-E.

In the proposed network codes, the text is now brought in a more correct contextual relation. In the former policies, the text was spread out in several sections. The unclear statements from the former UCTE Handbook still exist in the proposed network codes and will hopefully be corrected before the final release of the new codes.
For illustrative purpose, the key sections from the OS and OPS network codes are given below.

The N-1 *definitions* given in the proposed Network Code on Operational Security are stated as the following:

- N-1 criterion means the rule according to which elements remaining in operation within TSO's responsibility area after a contingency from the contingency list must be capable of accommodating the new operational situation without violating operational security limits.
- N-1 Situation means the situation in the transmission system in which a contingency from the contingency list has happened. (ENTSO-E 2013b, p.9)

The N-1 *requirements* in the proposed Network Code on Operational Security are stated as the following:

- Each TSO shall assess the risks associated with the potential effects of contingencies and prepare remedial actions after testing each contingency from its contingency lists and after assessing whether it can maintain its transmission system within the operational security limits in the N-1-Situation. The starting point for the contingency analysis in the N-Situation shall at any time be the up-to-date topology of the transmission system including planned outages. In the case of an N-1-situation caused by an unplanned outage, each TSO shall apply remedial actions in order to ensure that the transmission system is restored within operational security limits as soon as reasonably practicable and that this N-1-situation becomes the new N-situation. (ENTSO-E 2013b, p. 29)
- If after a contingency the transmission system is not compliant with the N-1-criterion, the TSO shall initiate remedial actions to recover compliance with the N-1 criterion as soon as reasonably practicable. If there is a risk of a post-contingency disturbance propagation involving interconnected TSOs, the TSO shall initiate remedial actions as soon as possible. Non-compliance with the N-1 criterion is acceptable in the following situations:
  a) during switching sequences;
  b) as long as there are only local consequences within the TSO's responsibility area; or
  c) during the time period required to activate the remedial actions. (ENTSO-E 2013b, p. 30)

If voltage deterioration jeopardises operational security or threatens to develop into a voltage collapse in either N or (N-1)-situation the TSO shall be entitled to instruct the DSOs, closed distribution networks and significant grid users with a connection point directly to the transmission system, to block the automatic voltage and reactive power control of transformers or to follow other voltage control instructions. As a consequence of these measures directed by the TSO, the DSO may have to disconnect significant grid users which are Demand Facilities in order to avoid jeopardising the transmission system. This is part of the defence plan. (ENTSO-E 2013b, p. 27)

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In the N-1-situation in normal state, each TSO shall keep power flows within the transitory admissible overloads, preparing and executing remedial actions including re-dispatching, to be applied within the time allowed for transitory admissible overloads (ENTSO-E 2013b, p. 28).

Each TSO shall include internal and external contingencies in the contingency list. External contingencies shall be defined in line with the methodology developed according to the provisions in the Network Code on Operational Planning and Scheduling. Each TSO shall differentiate between ordinary, exceptional and out-of-range contingencies, taking into account their probability of occurrence. In the treatment of classified contingencies, each TSO shall apply the following principles:

a) Each TSO shall classify contingencies for its own responsibility area;
b) When and as long as conditions significantly increase the probability of an exceptional contingency, the TSO shall include this exceptional contingency in its contingency list. The TSO shall determine the remedial actions necessary to maintain its transmission system within operational security limits or to mitigate the impact of exceptional contingencies as far as reasonably practical and economically efficient;
c) When and as long as out of the ordinary conditions increase the probability of an out-of-range contingency, the TSO shall use all available economically efficient and feasible means under its control to prepare remedial actions to mitigate the impact of these very exceptional conditions;
d) Each TSO shall determine the ordinary and exceptional contingencies based on the up to-date topology;
e) In order to account for exceptional contingencies with high impact on its own or neighbouring transmission systems, or with a high probability of occurrence, each TSO shall include such exceptional contingencies in its contingency list. The included exceptional contingencies shall be reassessed and if necessary the contingency list readjusted in the case of significantly changed operational conditions; and
f) Each TSO shall contribute to the development of a common methodology and criteria for coordination and, as far as technically feasible and economically efficient, harmonization of the key principles for establishment of contingency lists across the synchronous areas. (ENTSO-E 2013b, p. 29–30)

In Article 16 'Operational Security Analysis in operational planning' in the ENTSO-E Network Code on Operational Planning and Scheduling, it is stated that:

- "Each TSO shall perform operational security analyses for each of the time horizons specified[12] in N-situation by simulating each contingency from the TSO's contingency list in accordance with Article 13 of (NC OS) and verifying that the operational security limits defined in accordance with Article 8(5), Article 8(6) and Article 8(8) of [OS] in the N-1-situation are not exceeded.

- When simulating each contingency in accordance with Article 16(2), each TSO shall take into account the capabilities of the Significant Grid Users as mentioned in Chapter 2 of [OS].

- TSOs shall coordinate between them their operational security analyses in accordance with the Article 12(3) and Article 13(3) of [OS] and in accordance with Article 19 of this network code, in order to verify that operational security limits affecting their own responsibility areas are not exceeded.

[12] The time horizons are year-ahead, week-ahead (when applicable), D-1, and intraday (ENTSO-E 2013d, p. 17)

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- Each TSO shall use as a minimum Common Grid Models described in Article 12, Article 13 , Article 15 and where relevant Article 14 to perform the operational security analyses referred to in Article 17 and Article 18." (ENTSO-E 2013d, p. 18)

4.2 Summary

New ENTSO-E network codes are under preparation and halfway in the approval phase. The network codes presented in this chapter comprise operational security, planning and scheduling. According to the actual status of these proposals, the N-1 criterion is still the fundamental principle for reliability management. In addition, the TSOs shall assess the risks associated with contingencies and prepare remedial actions. Each TSO shall also differentiate between ordinary and exceptional contingencies in their contingency lists, taking into account the probabilities of occurrence.

In the proposed network codes, the text is brought in a more correct contextual relation. In the former policies, the text was spread out in several sections. The unclear statements from the former UCTE Handbook still exist in the proposed network codes and will hopefully be corrected before the final release of the new codes.

The description in Chapter 3, of the current mandatory rules and the results of the questionnaire survey, shows that the current practices follow some kind of risk based policy in addition to the purely deterministic N-1 criterion. In the proposals for coming network codes, the risk element is strengthened, e.g., by the inclusion of exceptional contingencies in the contingency lists and the explicit evaluation of probability of occurrence.

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5 RELIABILITY MANAGEMENT OUTSIDE EUROPE

There are some interesting reliability management trends outside Europe that can serve as an inspiration for future improvement of the European practice. In this chapter, experience from North America, New Zealand and Brazil is presented and discussed.

5.1 North America: NERC Preparing Probabilistic Methods

The North American Electric Reliability Corporation (NERC)[13] has the authority to issue mandatory rules on operating reliability[14] in power systems in North America (Canada, the USA and a part of Mexico). The increasing attention on the use of probabilistic tools for power system planning and operation is reflected in the work of the complex structure of NERC committees, subcommittees and task forces.

NERC has published a guidebook (NERC 2012b) on reliability issues. The guidebook clarifies current reliability assessment practices and objectives.

NERC guidebook is a document that is updated regularly by The Reliability Assessment Guidebook Task Force (NERC 2012b, p. v). NERC states two time horizons: long term planning and operational planning. Long-term power system planning encompasses the development, evaluation and assessment of various potential outcomes for one or more years into the future. Operational planning can and does use similar concepts as long-term power system planning except that the focus is the time period between one day and one year into the future. Both long-term and operational planning must address the uncertainty in the assumptions, such as forecast load, generation dispatch, the status of transmission elements. (NERC 2012b, p. 7–8)

According to NERC (NERC 2012b, p. 8) deterministic and probabilistic are different and complementary methods. Even though industry practices generally incorporate both deterministic and probabilistic methods, the requirements of the current NERC Reliability Standards are deterministic. (NERC 2012b, p. 9). NERC guidelines give guidelines for probabilistic adequacy assessment. The purpose of a probabilistic assessment is to produce enhanced resource adequacy metrics for NERC's Long-Term Reliability Assessment. (NERC 2012b, p. 58–60).

In April 2009, NERC published a special report (NERC 2009) on the integration of high levels of variable resource. The report highlights areas for further study, coordination, and consideration, including the use of probabilistic methods. It recommends the NERC Planning Committee to identify necessary data requirements to conduct planning studies and Planning Authorities and Reliability Coordinators to collect and retain such data. This action should identify how probabilistic approaches for transmission planning may go beyond current generally accepted industry approaches.

[13] The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to evaluate reliability of the bulk power system in North America. NERC develops and enforces reliability standards; assesses reliability annually via a 10-year assessment, and winter and summer seasonal assessments; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the Electric Reliability Organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. www.nerc.com

[14] NERC had used the term "security" until September 2001 when security became synonymous with homeland protection in general and critical infrastructure protection in particular. To remedy the increasing confusion over what they meant by security, NERC replaced that term with "operating reliability."

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5.1.1 Risk Assessment

A NERC report from 2010, Integrated Bulk Power System Risk Assessment Concepts (NERC 1020b), argues for an annual risk assessment approach and proposes the development of a set of risk management tools. The report focuses on the conceptual features of risk management while the methodological approach to apply such concept in practice is discussed in considerably less detail. According to the report, the portfolio of risk information includes:

- event driven indices;
- condition driven reliability indicators;
- standards/statute-driven violation risk measures.

Events are arranged according to severity and frequency. The severity of an event has a number of key characteristics, which are reflected in the definition of adequate level of reliability:

- duration of event (hours);
- amount of demand (MW) lost during the event;
- number of bulk power system components (including generation and transmission infrastructure) forced out of service during the event;
- unacceptable facility damage.

Risk is ranked by relative severity levels to quantify the impact of a particular event. Impact can be along multiple dimensions such as load (as proxy for customers) or loss of facilities (such as generators, transmission lines, substations or communications facilities).

The report (NERC 1020b, p. 11–12) defines the severity risk index associated with an event (SRI) to be the product of severity of the event and the rate of its occurrence. Mapping the severity and frequency in a coordinate-system, a curve with a constant risk index SRI, which is the product of severity and frequency (of an event), will be a hyperbola (for instance like the red curve in Figure 5.1).

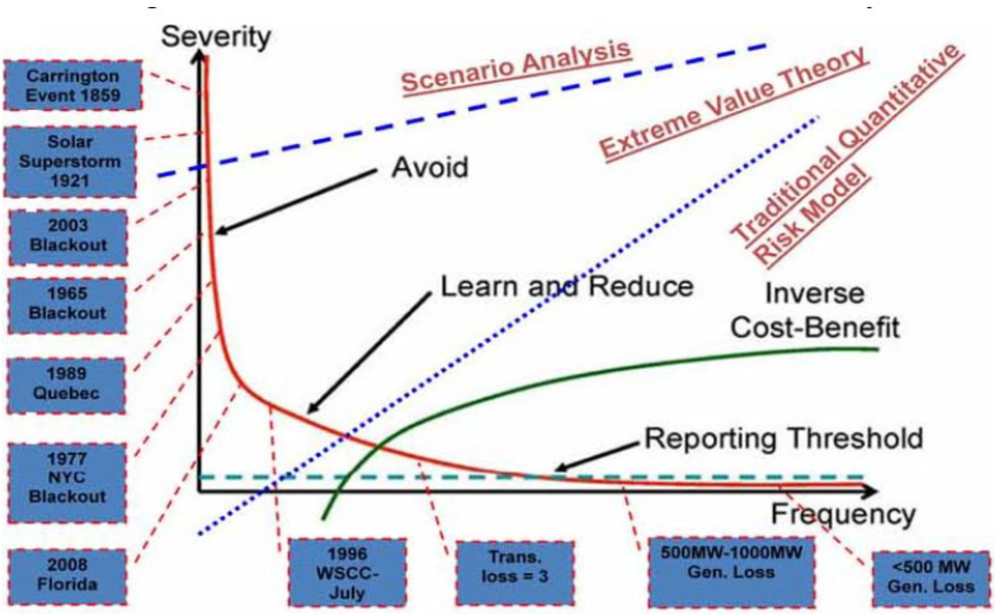

Figure 5-1: NERC recommendation on methods to measure risk in power systems (NERC 2010b, p. 17)

The research leading to these results has received funding from the European Union
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For low impact high frequency (LIHF) events, a large number of observations are available and traditional quantitative risk models are well suited for evaluations. For high impact low frequency (HILF) events, either scenario analysis or extreme value theory are recommended. It is noteworthy that for HILF events NERC also proposes to express impact in cost terms and suggests the following indicators: "cost of repairing damage; cost of re-fortifying systems to ensure no repeat incidents; cost to consumers; cost to industry due to lost productivity, products, or services; cost to government and taxpayers; cost of increased insurance" (NERC 2010b)

Some historic events are shown on the chart in Figure 5.1. According to the chart, events similar to the blackouts in 1965 and 2003 should be prevented and avoided. The incidents in Quebec (1989), New York (1977), Florida (2008) and WSCC (1996) should be evaluated in order to reduce the impact of similar events.

5.1.2 Established procedures and periodic reports

NERC prepares and publishes on its web pages (www.nerc.com) the following reports on the overall reliability and adequacy of the North American Bulk Power System, which is divided into 26 assessment areas, both within and across the eight Regional Entity boundaries:

- Annual Long-Term Reliability Assessment (LTRA) where the time horizon is 10 years;
- Annual Summer Reliability Assessment;
- Annual Winter Reliability Assessment;
- Special Assessments as needed.

To prepare these assessments, NERC collects and consolidates data from the eight Regional Entities. The data includes forecasts for on-peak demand and energy, demand response, resource capacity, and transmission projects. The use of this bottom-up approach accounts for virtually all electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The information is analysed to identify notable trends, emerging issues, and potential concerns regarding future electricity supply, as well as the overall adequacy of the Bulk Power System to meet future demand[15].

5.1.3 NERC's views on probabilistic methods

The following views on probabilistic methods are taken from the special report that discusses accommodating high levels of variable generation, especially from its Section 3.5.

NERC's Transmission Planning (TPL) Standards (NERC 2013b) are the foundation for transmission planning in North America. These standards are deterministic in nature and are based on the pre-specification of critical conditions. However, with the incorporation of variable generation resources, planning process will need to be augmented as the number of scenarios for which sensitivity analysis must be performed can dramatically increase. (NERC 2009, p. 46)

There is a benefit in pursuing probabilistic methods for both long-term and operational planning of the power system in order to more systematically and adequately quantify the risks associated with various planning options due to the high variability and probabilistic nature of many of the elements of the modern power system (variable generation, market forces, etc.). New tools and techniques for system planning are needed to accommodate the increased resource uncertainty and variability to complement existing deterministic approaches. Additional data will be required to support these new planning

[15] http://www.nerc.com/files/2012_ltra_final.pdf

The research leading to these results has received funding from the European Union
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processes: Probabilistic planning techniques and approaches are needed to ensure that bulk power system designs maintain bulk power system reliability. (NERC 2009, p. 46, 47)

5.1.4 The data problem

The report on accommodating large shares on variable generation also discusses the data concerning variable generation (NERC 2009, p. 46): "The necessary detailed datasets to study all types of variable generation are not yet available. To ensure the validity of variable generation integration study results, high-quality, and high-resolution (sub-hourly if possible) output data is required. Currently, historical data of variable generation performance is very limited and difficult to obtain. As substantial amounts of variable generation are expected to be added to the bulk power system during the next ten years, industry must begin obtaining the data as required to design robust bulk power systems. To this point in time, extensive modelling has been used to generate simulated data either directly or indirectly from historical weather data. The use of indirect data is far from ideal and, as real data becomes available, the validity of the original results should be reviewed."

New tools and techniques for system planning are needed to accommodate the increased resource uncertainty and variability to complement existing deterministic approaches. Both NERC actions and industry actions have been organized in order to meet the new requirements. (NERC 2009, p. 47)

It is a decisive precondition for the use of probabilistic tools that sufficient consistent data can be collected and organized. NERC collects data and other information required for the assessments. Some of the data may be considered confidential and will be treated correspondingly.

The following NERC data systems include essential reliability data:

- Generating Availability Data System (GADS) (Started in 2004)
- Transmission Availability Data System (TADS) (Collected since 2008)
- Demand Response Availability Data System (DADS) (Mandatory since 2011).

In December 2010, the NERC Planning Committee approved the final report on Methodology and Metrics (NERC 2010a). Data is supposed to be collected by the same 26 sub-regions (assessment areas) as for reporting for the Long-Term Reliability Assessment (LTRA), but in this context called "metrics reporting areas" (MRA). Figure 5.3 presents the areas.

The analyses for a certain NERC metrics reporting area MRA may require modelling of neighbouring areas. Therefore, a certain similarity of models and data is required. Some differences due to traditions or available tools are unavoidable. Therefore, a set of minimum requirements has been defined. According to the report (NERC 2010a, p. 3), the minimum required results are:

- Annual Loss-of-Load Hours (LOLH),
- Expected Unserved Energy (EUE), and
- Expected Unserved Energy as a percentage of Net Energy for Load (normalized EUE) for two common forecasted years – year 2 and year 5.

5.1.5 Observations on severity risk indices

This section presents observations on severity risk indices SRI during 2008–2012, which quantify system performance and highlight the most critical days. For comparison, Section 5.1.6 presents probabilistic calculations for 2014 and 2016. The comparison between observations and calculations is essential to the calibration of the probabilistic method

NERC's report 'State of Reliability 2013' (NERC 2013c) presents daily severity risk indices (SRI) for the years 2008–2012. The identification of high-stress days (meaning SRI exceeds 5.0) is a useful result. Among the key conclusions for 2012 are (NERC 2013c, p. 18):

- The top-10 most severe days in 2012 were all initiated by weather
- There were fewer high-stress days in 2012, with three days, compared to 2011, with six days.
- For SRI values less than 5.0, 2011 had better average performance than 2012.

The report (NERC 2013c) also presents severity risk indices (SRI) for the North American bulk power system (BPS). As a feature of SRI, it can also be extracted for various levels of the bulk power system. The report includes results for three large interconnections in the USA: Eastern Interconnection, Western Interconnection and the ERCOT Interconnection. The European analogies could be for example Ireland, Great Britain, the Nordic system, and the Continental Europe system. Figure 5.2 shows the results for the bulk power system.

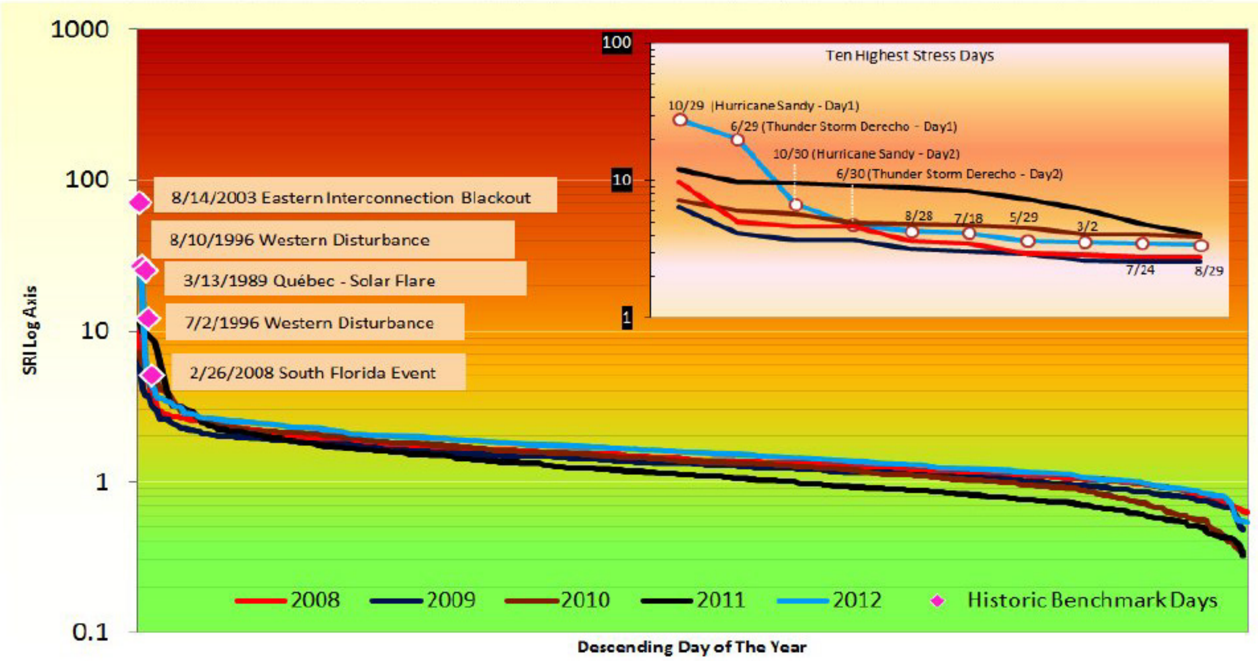

Figure 5-2: NERC daily severity risk Index results for 2008–2012 compared with historic events (NERC 2013c, p. 10)

5.1.6 Probabilistic Assessment for 2014 and 2016

The NERC Probabilistic Assessment (NERC 2013a) for 2014 and 2016 is the first report in the series of biennial probabilistic assessments covering all of the NERC Assessment Areas. It was presented in June 2013 as a complement to the 2012 Annual Long-Term Reliability Assessment LTRA (NERC 2012a), where the ten-year period observed was 2013–2022, with the 2013 summer as the initial season (NERC 2012a, p. i).

The composite generation and transmission assessment includes an assessment of generation adequacy which considers the ability to supply the aggregate electric power and energy requirements. Probabilistic tools are more widely used for the assessment of generation adequacy. Transmission adequacy is generally assessed using deterministic methods but some companies already use probabilistic transmission adequacy methods (NERC 2013s, p. 33).

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

Data has been collected for 26 assessment areas (presented in Figure 5.3). The data providers must meet certain minimum requirements which are listed in the introduction. Among them are:

- Use of an hourly load model that includes load forecast uncertainty;
- Model random outages for all units as random variables as opposed to derating the unit's capacity when modelling dispatchable capacity;
- Use of a transmission modelling method to incorporate major transmission constraints and limitations that is consistent with the assessment area's planning processes. (NERC 2013a, p. 6)

The main results are Expected Unserved Energy (EUE) and Loss-of-Load Hours (LOLH). In the report, the planned reserve margins for 2014 and 2016 are compared with the calculated EUE and LOLH. Most of the regions show small values of LOLH and EUE, which is consistent with the reserve margins.

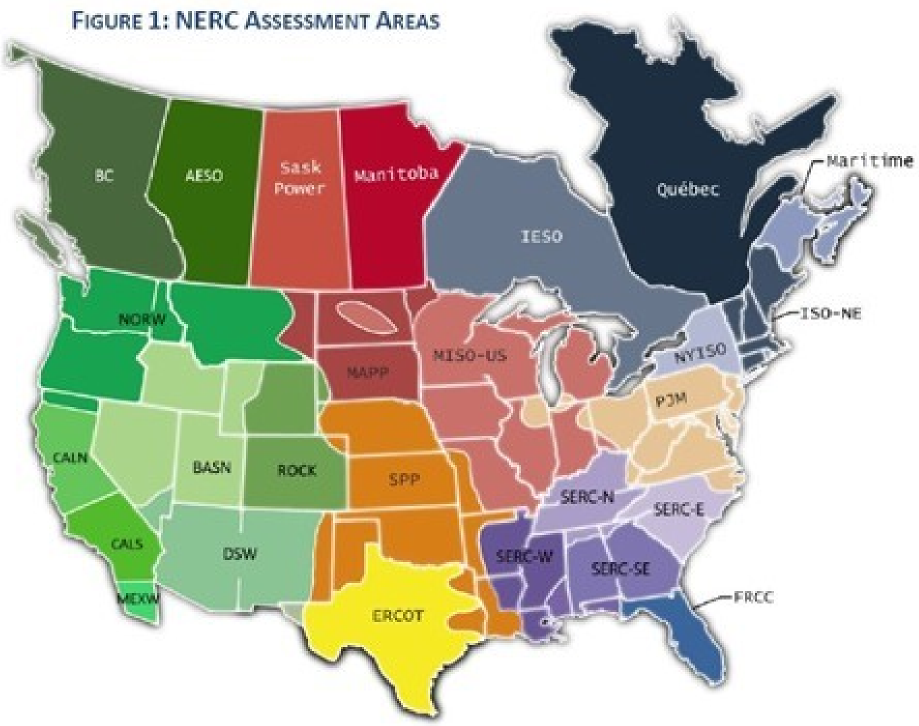

Figure 5-3: Overview of the 26 NERC assessment areas (NERC 2013a, p. 5)

Modelling for the next probabilistic assessment will start in the summer 2014

Improvements are anticipated within several areas such as modelling of load forecast uncertainty, intermittent resources, demand-side resources, and emergency operating procedures. Even the input data reporting will need improvement. More detailed analysis including the impact of specific generation (e.g., wind) or due to including the effect of transmission in this analysis may be possible in the future, at the moment simplified methods are used by some companies.

Another suggestion is to include a scenario analysis as part of the probabilistic assessment. Scenario analysis can help identify leading indicators of system stress and determine where vulnerabilities in the system exist. An example of scenario analyses for HILP event is presented in Section 5.1.1. Scenario assumptions such as non-responsive demand or increased forced outage rates of gas-fired generation due to natural gas unavailability could help gauge an area's resilience to the emerging North American bulk power system (BPS) risks.

The research leading to these results has received funding from the European Union
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5.2 New Zealand: advantages and disadvantages of probabilistic standards

5.2.1 Introduction

In New Zealand, according to the Electricity Industry Act 2010 (NZ Government 2010) and especially its Section 20, the Electricity Authority[16] must appoint a Security and Reliability Council (SRC)[17] with the function to provide advice on the performance of the electricity system and the system operator and reliability of supply issues.
The grid reliability standards are a set of standards against which the reliability performance of the existing grid (or future developments to it) can be assessed. The standards are based on the following principles[18] :

- An economic (probabilistic) standard for the whole grid, and the associated assessment of the costs and benefits of investment for reliability.
- A 'safety net' minimum reliability standard of N-1 for contingencies on the core grid. N-1 means that the system is planned such that, with all transmission facilities in service, the system is in a secure state, and for any one credible contingency event, the system moves to a satisfactory state. However, if more than one contingency event occurs, load may have to be shed to return to a satisfactory state.

The statements reflect an intention to balance the use of probabilistic and deterministic standards.
In 2008, Goran Strbac and Predrag Djapic from Imperial College in London, made an external peer review of the reliability standards in New Zealand (Strbac and Djapic 2008). The report is made for the New Zealand Security and Reliability Council but the comprehensive discussion on deterministic and probabilistic methods is general and relevant also in the European context. Appendix 2 summarises the main views of the report concerning the deterministic and probabilistic methods.

5.2.2 Recording System Performance

The transmission system operator in New Zealand, Transpower, must report essential performance data to the Security and Reliability Council.

At the Security and Reliability Council meetings, Transpower has presented interesting charts on system performance, such as ancillary service cost, frequency management, system events, emergency and warning notices, outage management and constraints binding. Figure 5.4 gives an example of charts on grid emergency and warning notice from 2011 showing a top in January and February that year due to insufficient generator offers and insufficient transmission capacity.

The Electricity Authority publishes informative annual market performance reports (NZ Electricity Authority 2014) including brief sections on transmission grid performance.

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[16] http://www.ea.govt.nz/

[17] Security and Reliability Council (SRC): http://www.ea.govt.nz/development/advisory-technical-groups/src/

[18] Grid Reliability Standards: http://www.ea.govt.nz/operations/transmission/grid-reliability-standards/

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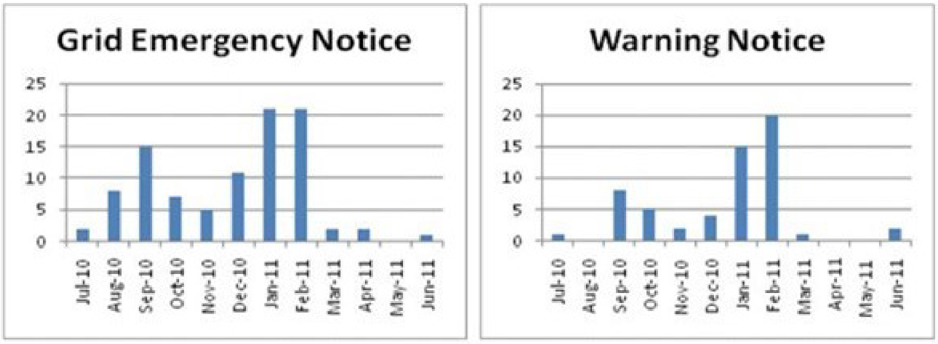
Grid Emergency Notice | Warning Notice



Grid Emergencies and Warning Notices were declared in Jan and Feb 2011 for insufficient generation offers in the Upper North Island and insufficient transmission capacity in the Waikato region.

Figure 5-4: Grid emergency and warning notice statistics for New Zealand 2010/2011 (NZ Security and Reliability Council 2011)

5.3 Brazil: recording operational performance

According to (Cisneiros et al. 2010), the planning of the Brazilian power system is based on the N-1 criterion and a range of measures for re-establishing normal security after the loss of essential elements. The operational rules also consider certain N-2-contingencies. The reference does not mention probabilistic criteria.

Performance indicators are important tools for observing and planning the interconnected power system in Brazil. Performance indicators have been defined for security, adequacy and reliability (Cisneiros et al. 2010):

- Security performance indicators – robustness:
  - Interconnected Power System
  - Interconnected Power System for N-1 Contingency Severity Level
- Adequacy performance indicators:
  - Voltage standards
  - Frequency standards.
- Reliability performance indicators:
  - Load Interruption Equivalent Duration
  - Load Interruption Equivalent Frequency.

The indicators are not fully defined in the paper. They are planned to be simple in order to maximize the use.

The performance indicators reflect the quality of transmission and supply service. They are calculated monthly and yearly and aggregated at different levels: system, subsystem, region, state or agent (Distribution Company or Free Consumer).

Cisneiros et al. present security performance and reliability performance indicators for the years 2000–2008 to (Cisneiros et al. 2010). The reliability performance indicators clearly reflect specific serious events in the years 2002 and 2005. Figure 5.5 shows an example.

The research leading to these results has received funding from the European Union Seventh Framework Programme under Grant Agreement No 608540.

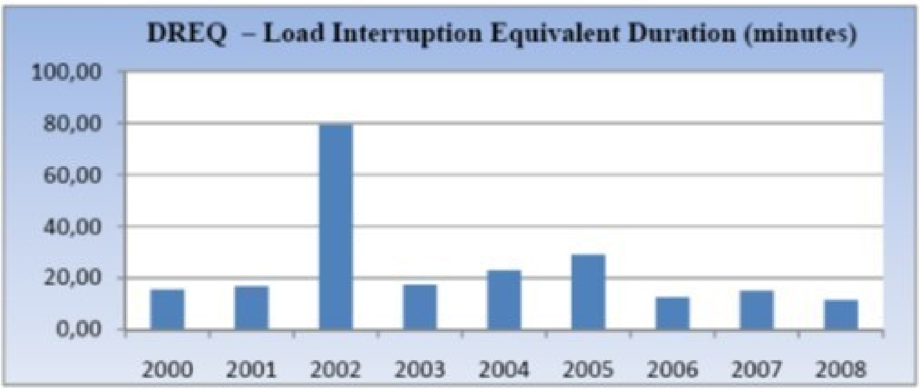


Figure 5-5: Brazilian reliability performance statistics for 2000–2008 (Cisneiros et al. 2010, p. 6)

The essential quality of the procedures described by Cisneiros et al. is the systematic recording of the operational performance of the power system and the use of the results for maximizing transmission system limits with adequate security and quality levels.

5.4 Summary

There is a widespread international interest for achieving the best possible trade-off between cost and risk of disturbances in the power systems. This is the background of the interest for probabilistic methods.

Methods and plans for reliability management in North America, New Zealand and Brazil have been examined in this chapter. Deterministic criteria are still the main tools in planning and operation of power systems. The North American Electric Reliability Corporation, NERC, has prepared probabilistic tools for several years. A huge effort was made and interesting progress has been reported.

The following three elements are central in NERC's preparations of probabilistic planning:

- Availability data has been collected from each of the 26 North American assessment areas for all essential grid elements over a suitable period of time. NERC is developing comprehensive data systems for estimating the availability of generation, transmission and demand response. The aggregated results are publicly available.
- Regional and local participants in the reliability work must have accurate power system models for the analysis of contingencies for their respective responsibility areas.
- For the calibration of the data and models system performance has been observed over a suitable period. The results are regularly published.

The research leading to these results has received funding from the European Union
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6 DRIVERS FOR AND BARRIERS AGAINST PROBABILISTIC RELIABILITY CRITERIA

6.1 Introduction

The aim of the GARPUR project is to explore new probabilistic criteria for reliability management. This chapter provides background information about drivers for and barriers against probabilistic reliability criteria in Europe, identifying why probabilistic reliability criteria should be used and which factors decrease applicability of such criteria.

This chapter has three parts: The first part (Sections 6.2 and 6.3) discusses drivers and barriers as seen from the questionnaire answers, which represent the opinions of nine European TSOs. The second part (Section 6.4) discusses the drivers and barriers based on the opinions provided by TSOs in the GARPUR workshop for the European TSOs on 7 April 2014. Section 6.5 discusses the drivers and barriers from the regulation and recommendation point of view. Section 6.6 presents probabilistic reliability methods proposed in the literature and seeks to identify drivers and barriers. Finally, Section 6.7 presents a synthesis of drivers for and barriers against probabilistic reliability criteria.

6.2 Drivers for probabilistic reliability criteria according to the questionnaire

6.2.1 Overview

To get an overview of drivers, it is interesting to take a look on the benefits that could be achieved by using a probabilistic reliability management framework. According to the answers of the TSOs (Q50 in Appendix 1), a new probabilistic reliability standard can give multiple benefits, as shown in Figure 6.2. The most often indicated benefits are an estimate for the reliability level of the system and a more efficient grid use. TSOs also listed the following potential benefits: (i) increase in wind or other variable production, (ii) less capacity given to the reserves and more capacity to power transmission, and (iii) more transmission capacity given to the market.

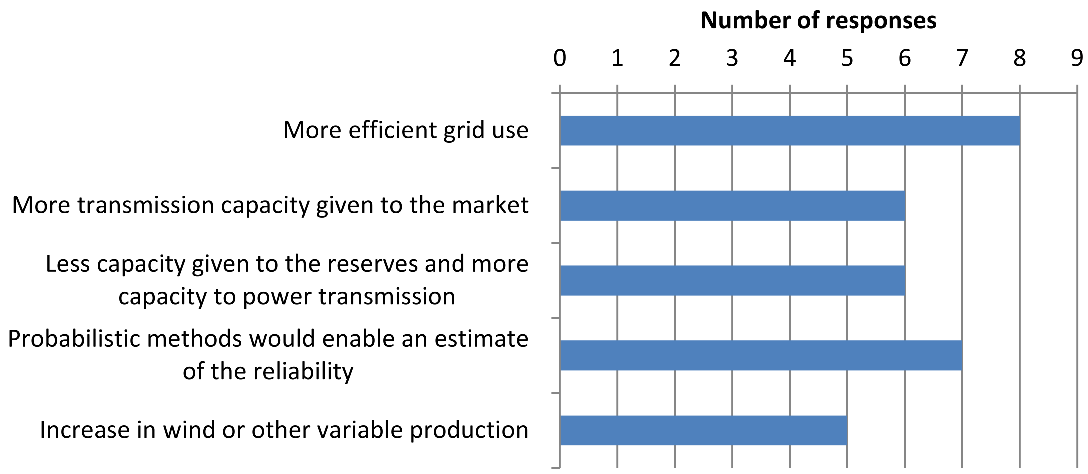

Figure 6-1: Benefits of a new probabilistic reliability standard according to nine TSOs answers to Question 50 in the questionnaire.

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The results are also presented in Table 6.1, where the TSOs' ranking of these benefits is presented. Five TSOs out of 9 said that more efficient grid use would be the most important benefit while 2 TSOs ranked it as the second.

Five TSOs reported that a probabilistic reliability criterion would be more useful regarding the integration of more wind or other variable in-feed.

Based on the questionnaire, the TSOs also find that being able to make an estimate for the reliability would be a useful benefit from performing probabilistic reliability analyses, since 7 TSOs reported this benefit. According to comments of TSOs, a reliability estimate would give a better understanding of the system, could help to rank N-1 secure power system states, and to compare different operation strategies.

Six TSOs out of nine mentioned that with a probabilistic reliability framework, less transmission capacity for reserve can be given and more capacity can be allocated for power transmission. Six TSOs mentioned more transmission capacity can be given to the market as a benefit of a probabilistic reliability framework.

Table 6.1: Benefits of a new probabilistic reliability standard classified according to TSOs and priorities (Q50 in the questionnaire in Appendix 1)

TSO	Priority				
1	More efficient grid use	Probabilistic methods would enable an estimate for the reliability	More transmission capacity given to the market	Increase in wind or other variable production	
2	More efficient grid use	More transmission capacity given to the market	Less capacity given to the reserves, more to power transmission		
3	More efficient grid use	Probabilistic methods would enable an estimate for the reliability	Increase in wind or other variable production	Less capacity given to the reserves, more to power transmission	
4	More efficient grid use	More transmission capacity given to the market	Less capacity given to the reserves, more to power transmission	Increase in wind or other variable production	
5	More efficient grid use	Less capacity given to the reserves, more to power transmission	Probabilistic methods would enable an estimate for the reliability		

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TSO	Priority				
6	More transmission capacity given to the market	Less capacity given to the reserves, more to power transmission	More efficient grid use	Probabilistic methods would enable an estimate for the reliability	
7	More transmission capacity given to the market	More efficient grid use	Increase in wind or other variable production	Probabilistic methods would enable an estimate for the reliability	
8	Other: security of supply	More efficient grid use	More transmission capacity given to the market	Probabilistic methods would enable an estimate for the reliability	Less capacity given to the reserves, more to power transmission
9	Other: rank a set of N-1 secure alternatives	Probabilistic methods would enable an estimate for the reliability			

6.2.2 More efficient grid use

The most important benefit of probabilistic reliability criteria according to Figure 6.1 and Table 6.1 is an efficient grid use, meaning more capacity to the markets and lower security margins. From the socio-economic point of view this means more effective use of the investment[19]. In the following sections, possible reasons for this answer are identified based on other responses in the questionnaire. There have been attempts to identify whether the TSOs that strictly follow the N-1 criterion are the ones that highlight efficient grid use as a benefit of changing to a probabilistic criterion.

Question 3 in the questionnaire asked whether the TSOs obey the N-1 criterion strictly. Six TSOs said they follow the criterion strictly and 3 said they do not follow it strictly (see also Section 3.3.3).

According to the TSOs, reasons for not using the N-1 criterion strictly are either structural properties of the grid or risk-based decision making that is allowed if consequences are limited to a certain geographical area. These answers also confirm that some TSOs consider risk or probabilistic criteria inherently already, as illustrated by the following examples:

[19] It is worth noting that more efficient grid use does not mean lower losses, an issue mentioned by some TSOs but in the category ‘Others (please specify)’.

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The TSOs were asked if they include probabilities in their interpretation of the N-1 criterion, such as ignoring some very rare faults (Q17). Three out of nine TSOs answered yes. They commented their answers (to questions Q17 and Q18) and said that this is only for a few special cases. An example of such a case is that a certain fault is not included in the contingency list even though the system would not withstand it. The problem will disappear in the future since this is temporary. Depending on the weather conditions, some additional double line and busbar faults may be monitored in addition to the standard N-1 faults.

Out of the six TSOs that do not consider probabilities in their N-1 interpretation, four say that the most important reason of changing the reliability criterion from N-1 to a probabilistic one, would be more efficient grid use.

All TSOs found it useful or important to use methods that estimate the reliability level by using information about probabilities and consequences of contingencies.

6.2.3 Deficits in the existing methods

In Q32 of the questionnaire, we asked whether there are deficits in the existing reliability management methods. Five TSOs did not see areas that the existing methods fail to cover. Other TSOs listed that the existing methods fail to cover the following areas:

1. The main problem with current methods is that they do not handle the growing uncertainties we have in operating the grid. This implies that not all cases are covered.
2. A higher degree of probabilistic planning would probably be OK.
3. One of the most difficult parts is to correctly represent the actual handling of outages when planning the grid. In other words, the consequence of a contingency is very difficult to calculate when planning.
4. The probabilistic element is clearly missing in today's methodologies.
5. Interdependencies of faults in large scale power systems

Besides the deficits in methods, the TSOs were also asked about deficits in existing software tools (Q37 in Appendix 1). According to the answers, the software tools fail to cover the following areas:

- Forecasting errors (Generation, load, etc.);
- Possible failure of corrective actions;
- Probabilistic assessment in general;
- Global view on mutual impact of cross border N-1 & remedial actions + worst case combinations cf. Germany winter study;
- Production prediction tools – estimating production from renewables – especially PV
- Congestions in neighbouring countries;
- There is a lack of flexible tool for assessing system related and reliability issues;
- Remedial actions in contingency analysis are missing;
- Some development is needed for getting the probabilities of contingency calculations so that the results would be not just the consequences but also probabilities;
- The biggest problem for the software tools are the data.

6.2.4 Willingness to use probabilities with N-1

The TSOs were also asked how they model or take the probabilities of external threats into consideration (Q28 in Appendix 1) and how they model or take into consideration low probability high impact events (Q31). Some TSOs mention that they consider probabilities or frequencies of some specific events, use expert evaluations or qualitative evaluations, and some use additional back-up personnel during exceptional weather without explicitly mentioning that they have calculated probabilities. The issues

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mentioned below present a step from purely deterministic into more probabilistic approach. Since the N-1 criterion is deterministic in nature, TSOs seeing the need for using probabilities is a driver: the TSOs already now use probabilities in cases where they find it useful and have tools for it.

The TSOs listed the following aspects that they use when considering external threats *in planning* (answers to Q28):

- Strength of towers as a function of wind speed; heightened security at some critical substations.
- Long-time weather conditions, avalanche and landslide threat.
- For substation component faults, long term average probabilities based primary on own system operation experience and fault statistics, for overhead line faults also seasonal variation of disturbance frequencies are considered. FMEA (failure mode and effect analysis) is done with load flow and supplementary dynamic simulation runs on some representative snapshots. Human errors are assumed to be included in primary component failure rates.

In system operation, the TSOs listed the following issues:

- Forecasted values of weather conditions are used to forecast RES production for reliability assessment. However probability of forecasting error is not taken into account. The emergency plans give additional elements to take into consideration when assessing risks.
- Short term weather including lightning. Safety precautions. Personal protections.
- Increase the preparedness level of human resources in control centres and back-up personnel during exceptional weather etc.
- TSOs also mentioned the following aspects *without specifying the time horizon*:
- The N-1 criterion is dependent on the weather conditions.
- Weather condition, expected market (participants) behaviour
- If applicable, such (high impact low probability) events are mostly evaluated and described qualitatively in the decision making process, e.g. at board meetings etc.
- Sometimes such (high impact low probability) events are described using a risk matrix with consequence on one dimension and probability on the other dimension.
- Select the critical stations and define specific measurements e.g. water flooding.

In question Q31, where the TSOs were asked how they model or take into consideration low-probability high-impact events, the TSOs listed following issues:

- On a case by case basis.
- Low-probability high-impact events are considered in planning the grid on selected situations.
- By Major Disturbance probability estimation analyses. These are executed from time to time when fundamental changes in the power system are foreseen. The objective is to estimate analytically possible fault sequences and their consequences with power system simulations in order to support balanced development of the overall system.
- These events should be dealt with the defence plan.
- By expert evaluation of the reliability level of the power system in case of an event with low-probability and high impact.
- Not considered, except tower loss for one critical line to the coast.

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6.3 Barriers against probabilistic reliability criteria according to the questionnaire

6.3.1 Overview

In the previous section, potential drivers for a new probabilistic reliability criterion have been presented. In the questionnaire, potential barriers were inquired as well. Figure 6.2 presents the barriers against a probabilistic criterion based on the responses of the TSOs to question Q51 in Appendix 1.

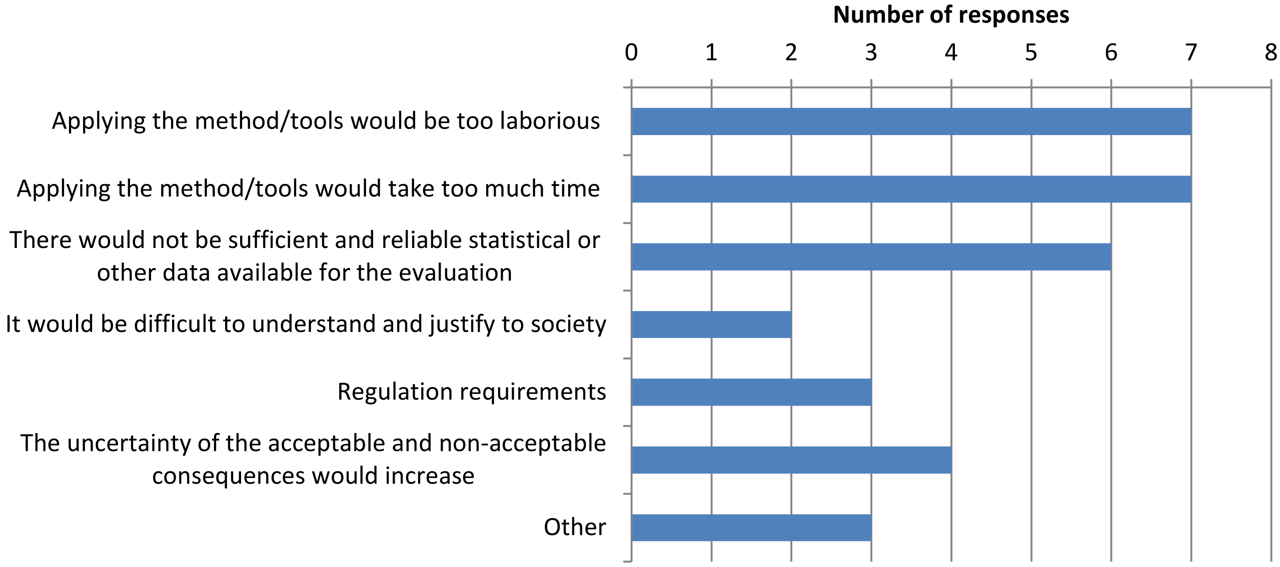

Figure 6-2: Different barriers against probabilistic reliability criterion according to the answers to Q51 in the questionnaire

The figure shows that 7 out of 9 TSOs think that applying the method/tools would be too laborious or take too much time. Six TSOs claim that there would not be sufficient and reliable statistical or other data available for the evaluation of such a criterion. Four of the TSOs are concerned that the uncertainty of the consequences would increase. Some of the TSOs even say that the regulation requirements are barriers against a probabilistic reliability criterion.

The answer 'other' includes the following barriers:

- Difficulty or inability to convince people involved of the added value of the approach.
  Impact of global probabilistic reliability decision making could lead to unacceptable situations for individual grid users while N-1 is a criteria acceptable for each individual user.
- We haven't found tools that are able to calculate probabilistic reliability on meshed grids in a satisfactory manner. There are a lot of practical issues involved as well as inherent problems in the methodology.
- Might be uncomfortable for the operator.

6.3.2 Computational burden and data

The main concerns of TSOs are that the probabilistic reliability criteria are too laborious and time consuming. Also a lack of data is a concern. The TSOs, however, collect data regarding failures of components as the results illustrated in Figure 6.3 shows. The data under the title 'other' includes data on

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phase-shift transformers, current and voltage transformers, switchgears and reactive power devices. Moreover, all TSOs are willing to share data with other TSOs and only few TSOs set conditions on data sharing as responded to Q46.

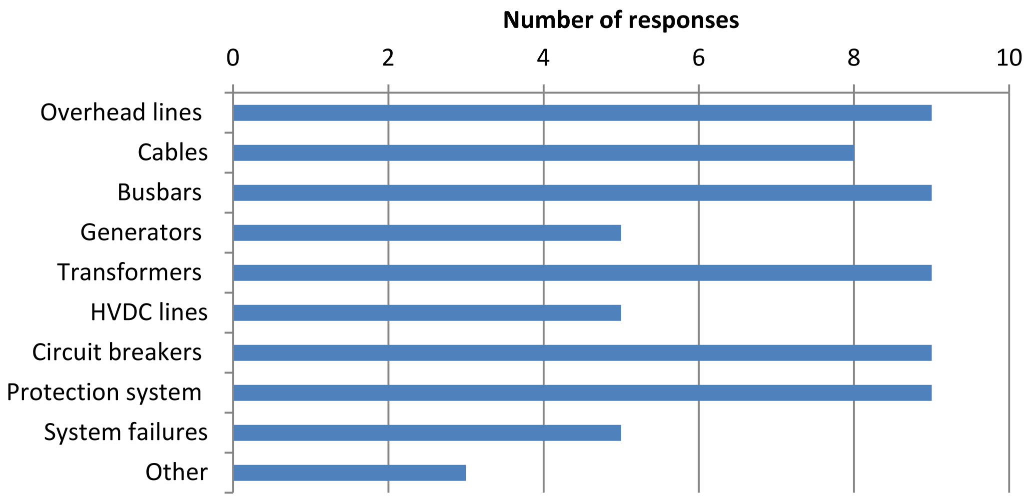

Figure 6-3: Components for which the TSOs collect and process reliability data (number of faults, fault causes, repair time) according to Q46

6.3.3 Regulation and society

Also administrative barriers or regulation may hinder application of probabilistic reliability criteria. The methods and criteria used may be strictly controlled by the national regulators. Therefore, the TSOs may not be able to apply a probabilistic criterion because the regulation is strictly deterministic. Regulatory issues were reported as a barrier by 3 TSOs. Moreover 1 TSO mentioned that one barrier could be the difficulty of compliance monitoring if a probabilistic criterion would be applied. Also some data may have a confidential nature and therefore it is not available for use outside the TSO of origin.
Only 2 TSOs answered they expect probabilistic criteria to be difficult to justify to the society.

6.4 Drivers and barriers according to the GARPUR TSO Workshop

6.4.1 Workshop

The GARPUR Workshop for the European TSOs was organized on 7 April 2014 in Brussels. In the workshop, the participants (both TSOs and other GARPUR partners) were given a task to list drivers and barriers to a probabilistic reliability framework. The answers are grouped in the following. Note that the grouping in the following sections and in Appendix 3 is done by the authors of this report. The only task of the participants was to list the drivers and barriers. The exact answers are in Appendix 3.

6.4.2 Drivers

The drivers can be grouped as follows:

- More efficient grid use (including technical factors and factors related to having a better balance between costs and reliability;
- More transmission capacity given to the market;

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- Probabilistic methods would enable an estimate for the reliability;
- Increase in wind or other variable production.

Among the answers about drivers, there were also answers that do not quite belong to but partly overlap any of the groups mentioned above. One driver mentioned states that since N-1 is already at certain times overruled, there is a need for an accepted method with more accuracy. This calls for a more analytical approach of what is (to some extent) already in use. One answer told that the customers, stakeholders and politicians push the TSOs to keep the reliability high and the tariffs low.

Dealing with probabilities and uncertainties were mentioned in the list of drivers. One answer mentioned open markets that add extra uncertainties to physical flows and to money flows. Some answers looked at the failure rates and claimed that the N-1 principle does not take into account differences in the failure rates of new and old components or between different components (such as transformers and lines). Therefore, with N-1 there is no indication on what to improve or the evaluation of the reliability will not be correct.

Power generation was mentioned as a driver as well. One answer mentioned that large generators (as for instance nuclear power plants) will be phased out and another mentioned the power of large units ("volume of bigger units") compared to the grid. New aspects such as demand side response were mentioned too.

Aging assets, need for more flexibility and large changes in power systems were also drivers in this list.

6.4.3 Barriers

The barriers listed in the TSO workshop (listed Appendix 3) can be grouped as follows:

- Complexity of the computation
- Lack of methods
- Laborious transition
- Reluctance of change
- No data, no accurate data, or no trust in data
- It would be difficult to justify to society
- Regulation requirements
- No experience (with probabilistic reliability criteria) so far.

Compared to the questionnaire answers, most issues listed above are the same. However, there are also new barriers such as reluctance of change and no experience so far. When answering to the questionnaire, many TSOs agreed that applying the probabilistic methods would be too laborious and take too much time. In the workshop answers however, it seems that it is neither much time nor laboriousness in focus but rather the complexity. Only one answer mentioned the time explicitly, the others just listed the complexity. If the probabilistic reliability criterion will be very complex and difficult to understand, it will be difficult to justify to the society. Some answers state that it is not acceptable that the new criterion is a black box; it must be transparent and clear enough.

A detailed list of barriers is given in Appendix 3.

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6.5 Drivers and barriers according to NERC

6.5.1 Drivers according to NERC

According to NERC, with the incorporation of variable generation resources, the planning process will need to be augmented as the number of scenarios for which sensitivity analysis must be performed can dramatically increase. (NERC 2009, p. 46). Also NERC states that there is a benefit in pursuing probabilistic methods for both long-term and operational planning of the power system in order to more systematically and adequately quantify the risks associated with various planning options due to the high variability and probabilistic nature of many of the elements of the modern power system (variable generation, market forces, etc.). (NERC 2009, p. 46)

6.5.2 Barriers according to NERC

NERC identifies the lack of data of variable generation as a barrier that needs to be solved before it is possible to fully use probabilistic methods. According to NERC, the necessary detailed datasets to study all types of variable generation are not yet available. To ensure the validity of variable generation integration study results, high-quality, and high-resolution (sub-hourly if possible) output data is required." (NERC 2009, p. 46). New tools and techniques for system planning are needed to accommodate the increased resource uncertainty and variability to complement existing deterministic approaches. Both NERC actions and industry actions have been organized in order to meet the new requirements. (NERC 2009, p. 47)

6.6 Regulation – a driver or a barrier?

6.6.1 Introduction

Regulators play an important role in promoting efficient energy markets by defining and monitoring rules and targets for TSOs and market players. The regulation can be a major driver for or a barrier against probabilistic reliability management depending on the contents of the rules.

The TSO questionnaire revealed that regulation is considered as a barrier by three TSOs out of nine as Figure 6.2 shows. The regulation can also be seen as a driver. Since regulation is an issue that can be both driver and barrier, two examples from Norway and the Netherlands present how the regulation can be a driver.

6.6.2 Norwegian quality of supply regulation

Socio-economic principles for planning and operation of the power system were introduced in Norway by the Energy Act of 1990. This has been an important driver for gradually introducing quality of supply regulations. The Norwegian TSO (Statnett) is responsible for facilitating an efficient power market and a satisfactory quality of supply (NVE 2014). Since 1995, interruptions of electricity supply shall be recorded and reported (annually) to the Norwegian Water Resources and Energy Directorate (NVE, the energy regulator) (NVE 2014).

This mandatory reporting includes data on the number and duration of interruptions and on energy not supplied to end-users. All network companies including the TSO are required to employ the current requirement specifications for FASIT which is the Norwegian standard for collection and reporting of fault and interruption data (Heggset et al. 2009). In addition, the TSO shall prepare and distribute fault

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statistics based on reporting of operational failures in the transmission and distribution grids including connected generation units. Fault statistics for the Norwegian power system have been issued annually for more than 20 years.

Besides the reporting of interruptions, the quality of supply regulations comprises technical requirements and the cost of energy not supplied (CENS) arrangement which was introduced in 2001. CENS is a model for incentive based financial regulation which is based on the mandatory reporting of interruptions (NVE 2014). In this arrangement, the interruption costs are calculated in FASIT for each interruption using cost data for six different customer groups. The cost data are represented as a function of time of occurrence and interruption duration (Kjølle et al. 2009). These data are based on national customer surveys using state of the art methodologies on estimating costs of interruptions. (Kjølle et al. 2008), (Hoffman et al. 2010

The FASIT standard ensures that fault and interruption data are uniformly recorded. Based on these data, reliability data can be provided as input to probabilistic reliability analysis which is a necessary methodology for estimating future quality of supply as well as expected interruption costs (CENS).

The main reliability principle for the transmission system is the N-1 criterion. However, there are situations where consequences are accepted. The policy for operation states that for an intact grid, a maximum load shedding of 200 MW is acceptable for maximum 1 hour. Higher risk is acceptable during maintenance: the load shed can be up to 500 MW for maximum two hours. A connection point shall not have more than two interruptions per year. After an interruption, the grid shall be operated in such a way that the risk of a new interruption for the same point is low. This policy for operation is based on socio-economic analyses.

The Norwegian regulations relating to contingency planning in the power supply system gives provisions for handling extraordinary situations (high impact low probability events). It is e.g., as of 2003 mandatory to perform risk and vulnerability analyses to identify the risk potential of operations and to have a contingency plan as well as to carry out exercises.

6.6.3 Dutch regulation

Reference (de Nooij et al. 2010) has developed a cost-benefit framework for energy reliability that considers the new rule introduced by the Dutch government at the time of the publication. According to (de Nooij et al. 2010), in 2005 the Dutch Ministry of Economic Affairs changed the rule for design of power systems to a rule where the N-1 criterion is used. The criterion may be ignored if the costs to fulfil reliability exceed the benefits.

The new rule for the design of electricity grids in the Netherlands is (de Nooij et al. 2010): “[…] by law a grid with a voltage of 220 kV or more must be designed and operated in such a way that a single interruption has no impact on the transport of electricity. This rule also applies to the grids with a voltage between 110 kV and 220 kV, *however the rule may be ignored if the costs exceed the benefits*”. The section in italics was added to the existing rules in 2005 (de Nooij et al. 2010).

The framework developed in (de Nooij et al. 2010) is based on the cost-benefit analysis. The benefits are the increased reliability and costs are the costs of an investment. To calculate the benefits, the following parameters are needed before and after an investment:

- frequency of supply interruptions;
- expected duration of interruptions.

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Moreover, a cost parameter is needed that indicates the cost of an electricity supply interruption to society. This parameter is needed in order to get a monetary value for the increased reliability. De Nooij et al. (2010) reviewed the methods to estimate this parameter. In the GARPUR project, this issue has been discussed already in Deliverable 1.1 (GARPUR Consortium 2014) and therefore it is not considered here.

As the investment improves the reliability of the power system for many years ahead, the obtained net value of benefits and costs is discounted to the present value using a discount factor of 5.5 % (de Nooij et al. 2010).

6.7 Drivers and barriers according to literature

6.7.1 Overview of literature

From the drivers and barriers point of view, it is important to consider the benefits and weaknesses present in the existing methods for probabilistic or risk based reliability assessments.

In the following sections, existing literature relevant for the drivers and barriers has been reviewed. The covered literature can be roughly classified into two categories:

- State of the art according to a CIGRE working group (CIGRE 2010)
- Examples of methods for probabilistic or risk based reliability assessment, including comparison of deterministic and probabilistic approaches, are covered, e.g., in publications (Kirschen & Jayaweera 2007), (Karangelos et al. 2013), (Uhlen et al. 2000), (GARPUR Consortium 2014).

6.7.2 State of the art according to CIGRE

CIGRE working group C4.601 reviewed the status of techniques for risk-based and probabilistic planning in power systems. Three major drivers for risk-based and probabilistic methods were identified (CIGRE 2010):

- the liberalization of the electric industry;
- increase of renewable generation and mainly wind generation;
- an increased public concern regarding environmental impact of new transmission facilities.

More specifically, the working group has found the following weaknesses of deterministic assessments that a probabilistic approach would overcome (CIGRE 2010):

- Deterministic assessments do neither evaluate the probabilities of events nor the severity.
- Risk factors such as ambient conditions, substation configuration and line length are not taken into account even though they may affect the likelihood of an event occurring.
- The deterministic N-1 criterion does not deal with the “worst” case. The determination of the technical standard is not based on a probabilistic approach.
- Severe outages may be due to the failure of multiple network components. The alternative is to bring risk management into planning practice and keep system risk within an acceptable level.

CIGRE Brochure 434 (CIGRE 2010) presents that the definition of N-1 may vary including the following cases:

- “N-G-1 where the prior outage of the largest relevant generator is taken into account;
- N-1-1 where the transmission system must tolerate an unplanned outage at the time another item or plant is out of service for maintenance; and

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- N-2 for locations where very high reliability is required, such as central business districts."

According to CIGRE Brochure 434 (CIGRE 2010), the probabilistic approach has a potential to deal with many of the uncertainties facing transmission planners and to assess economic merit of investment proposals. It also highlights that the N-1 criterion does not have a formal trade-off between reliability and the cost of achieving a certain standard. The brochure presents an example of this situation: (CIGRE 2010, p. 2-5):

> "For example, an N-1 approach would not differentiate between a 10 km transmission line supplying a highly meshed part of the network and a 200 km line supplying a less meshed load centre. Clearly both the probability of failure of the long line and the consequences of a failure could be higher.
>
> The probabilistic approach also allows an economic criterion (CIGRE Working Group C4.601, 2010) p. 2-6, exemplified by how this is used in Victoria, Australia: "This approach is used in Victoria (Australia) and in New Zealand, where there is an added 'safety net' on those parts of the transmission grid where consequences of a failure are greater than 150 MW. For these parts of the New Zealand transmission grid a safety net of N-1 is provided."

One identified drawback of a probabilistic approach is the difficulty to measure the benefits. This difficulty contains the following aspects (CIGRE 2010 p. 2-6):

- The variation in reliability of supply to customers and challenges in estimating the corresponding costs where many different customers are served;
- Market benefits of investments when compared with the 'no investment' or 'alternative investment' cases
- Benefits arising from mitigation provided for High Impact Low Probability (HILP) events.

The probabilistic approach has two components: Probabilities and consequences. The estimation of probabilities is done using historical data, but the CIGRE brochure recommends that at least the following issues should be considered (CIGRE 2010), like those mentioned in Section 3.2:

- fault frequencies may be affected by local conditions, maintenance history and operating conditions, making aggregation of data from other regions less reliable;
- there is a lack of useful data on high impact low probability (HILP) events;
- Planners should have confidence in data accuracy and relevance while estimating the probabilities.

The consequences of contingencies can be assessed, e.g., in terms of energy not supplied (CIGRE 2010). There is a wide range of literature on methods to model consequences of contingencies. An extensive review of state of the art on probabilistic reliability assessment methodologies including socio-economic impact is given in the first deliverable from this work package (GARPUR Consortium 2014). Some of the major challenges regarding consequence assessment are, e.g., related to dependent failures and cascading phenomena. Several publications present cascade modelling methods and tools and the strengths and weaknesses of the methods (Vaiman et al. 2012), (Baldick et al. 2008), (Vaiman et al. 2011, (Papic et al. 2011).

The CIGRE report (CIGRE 2010) even points out the importance of control systems in power system planning studies because they have a big impact on the consequences of contingencies. The report presents examples related to the mode of control for the turbine-control system, power factor control, power system stabilizers and automatic stator current limiters.

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6.7.3 Comparison of deterministic and probabilistic approaches

Table 6.2 presents a comparison of the differences between a probabilistic and deterministic planning according to CIGRE brochure 434 (CIGRE 2010).

Table 6.2: Summary of differences between probabilistic and deterministic planning (CIGRE 2010)

	Probabilistic planning	**Deterministic planning**
Contingency levels	Multiple levels of outages can be considered. Probabilistic planning tools can be used for analysis of multiple contingencies beyond N-2 events.	Automatic assessment of worst case scenarios limited to N-2 events due to computational intensity.
Economic decision making	Facilitates economic decision making for investments and provides basis for selection of the best alternative over a range of scenarios.	Often involves subjective judgment and is not useful to assess the economic worth of an investment
System utilization	Probabilistic planning allows increased utilization of assets. Some probabilistic operating tools may be required to realize this.	The system capacity is planned for worst-case scenarios, which have low probability of occurrence. As a result, system capacity utilization is not always efficient.
Consideration to external factors	With probabilistic planning external factors such as environment, social and economic benefits can be considered in the analysis although some are difficult to quantify in monetary terms.	Deterministic planning cannot adequately address external factors.
Selection and ranking of contingencies	A wide variety of contingencies can be selected based on operational criteria. Ranking of contingencies is also possible based on their historical occurrence rates.	A limited number of contingencies are selected based on extreme operating conditions. Economic ranking is not implicit but can be done.
Load profile	Load profiles can be selected based on hourly, daily, or annual patterns. Even seasonal load profiles can be selected. Much more information available on exposure to security risks.	Deterministic planning is based on seasonal Peak, Medium, or Low demand values. A real-time system simulation is normally not considered in the planning process
Analysis Conditions	Both steady state and dynamic conditions are used in probabilistic planning	No difference – both steady state and dynamic analyses are used to assess compliance with the deterministic criteria.

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	Probabilistic planning	Deterministic planning
Reliability Indices	A variety of reliability indices can be calculated	Indices can be calculated but are not normally part of the deterministic criterion.
Criteria for planning process	The probabilistic planning process is still evolving and an analyst has to be careful in selecting models and input data.	The deterministic planning process is well established.
Availability of data	Data for probabilistic planning is difficult to obtain and the quality of the data will largely influence the outcomes. Few utilities maintain and ensure quality of data for probabilistic planning.	Power system models and applications are widely accepted and benchmarked. Not reliant on asset performance data.
Robustness of analysis	Probabilistic planning is often used in conjunction with deterministic planning to provide a check on robustness to the system as a whole.	A utility is satisfied with the use of deterministic planning alone. The planning is normally supported by additional economic and dynamic studies.

Karangelos et al. (Karangelos et al. 2013) investigated the stakes of introducing probabilistic approaches for the management of power system security. In this reference, initial steps have been done in order to construct a globally coherent decision making framework for security management from long-term system expansion, via mid-term asset management to short-term operation planning and real-time operation. The paper concentrates on real-time operation and on decision making between preventive and corrective control alternatives. In this paper, the following issues are mentioned as drivers for a probabilistic approach to power system reliability:

- the new threats related to the ageing of the power system infrastructure;
- the growing uncertainty resulting from increasing penetration of renewable and dispersed generation, and;
- emerging smart grid technologies.

Moreover, the following barriers against using probabilistic tools are also mentioned:

- data quality issues;
- computational limitations;
- the allocation of security provision and service interruption costs amongst control areas and end-users, and;
- methodological limitations in the assessment of the social benefit of moving away from the N-1 criterion.

Kirschen and Jayaweera give a comparison of risk-based and deterministic security assessments (Kirschen & Jayaweera 2007). They argue that the N-1 criterion provides only a limited perspective on the actual level of security of a power system and a risk-based approach provides considerably more information on which to base operating decisions. Moreover, the authors point out that the risk calculation should not be limited to a predefined set of contingencies but should factor in the actual probabilities of outages leading to load disconnections.

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Kirschen and Jayaweera (2007) also show that the deterministic N-1 criterion does not imply a constant level of risk. The results are illustrated in Figure 6.5, where it is illustrated that the N-1 security criterion boundaries do not match with the reliability contours measured in terms of the expected energy not supplied. Indeed, the N-1 security boundaries are almost perpendicular to the contours in the two cases.

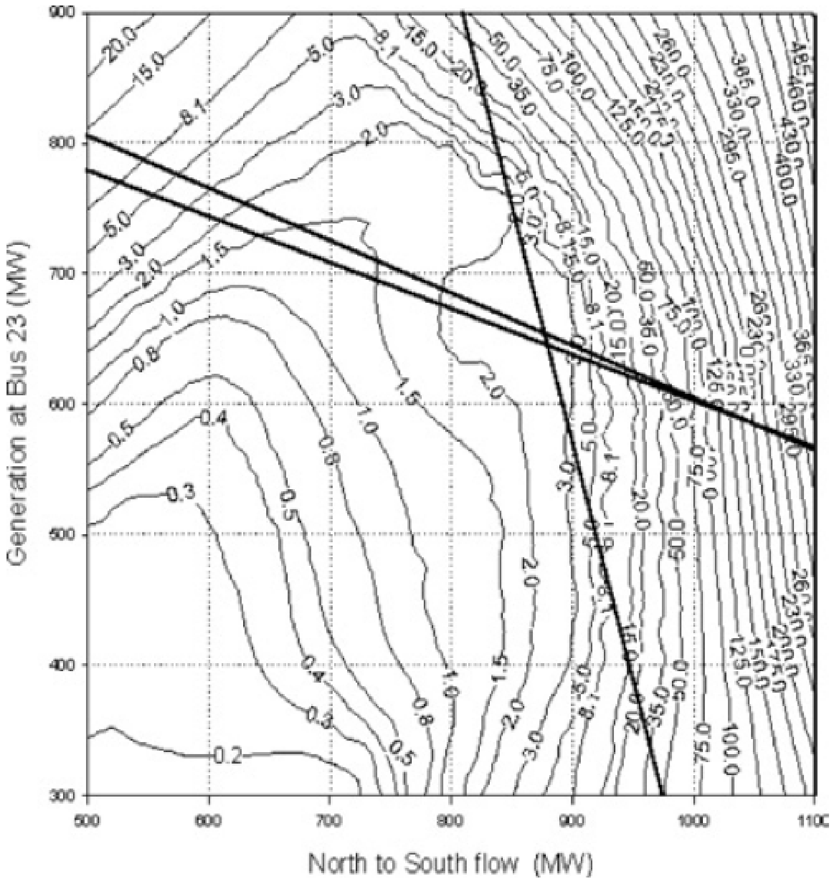

Figure 6-4: This figure presents a result of a risk-based security assessment (Kirschen & Jayaweera 2007). N-1 criterion does not guarantee a constant level of risk in terms of reliability. The contours are the risk levels in terms of expected outage costs and the solid lines are the N-1 security criterion boundaries.

Uhlen at el. (Uhlen et al. 2000) developed a probabilistic security criterion to determine transfer limits of a power system. The criterion considers the sum of expected interruption costs and congestion costs. The transfer limit minimizing the total cost is chosen. The optimal transfer limits based on this approach is compared to the transfer limit based on the deterministic N-1 criterion. Case studies show that by increasing the transfer limit in fair weather considerable economic savings and increased efficiency can be achieved without significant reduction of security. On the other hand, e.g., during adverse weather conditions, the N-1 constrained transfer limit may not provide sufficient security. Such a probabilistic security criterion may in combination with practical measures, provide more flexibility in the determination of transfer limits (Uhlen et al. 2000).

As a driver to a probabilistic reliability criterion, integration of fluctuating in-feed in power systems has been identified in literature. Therefore, for systems with fluctuating in-feed, such as wind power or PV in-feed, methods to re-formulate hard constraints with probabilistic constraints have been presented (Vrakopoulos et al. 2012), (Vrakopoulos et al. 2013a), (Vrakopoulos et al. 2013b), (Roald et al. 2013), and

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(Mäkelä & Andersson 2013). These methods replace the N-1 criterion and hard constraints with chance (or probabilistic) constraints.

6.8 Synthesis of drivers and barriers

Based on the questionnaire, TSO workshop, and literature a synthesis about drivers and barriers is given in Table 6.3. The literature and questionnaire suggest that the main drivers are an efficient grid use, to get an estimate of reliability, and integration of variable production. The main barriers identified based on the literature and questionnaire, are the status of data to provide probabilities and the difficulty to model the consequences.

Table 6.3: Results of a synthesis: drivers for and barriers against probabilistic reliability criteria

Drivers	Barriers
• **Efficient grid use** An efficient grid use and more transmission capacity given to the market are important benefits according to the questionnaire and literature. • **Estimate of reliability** An estimate of the reliability can be useful (stated by 7 TSOs out of 9 in the questionnaire). According to literature, a variety of reliability indices can be calculated. • **Integration of renewables** The European power system is going to integrate a high share of renewable generation in the years to come. Renewables have different characteristics than conventional generation, such as high variability, unpredictability and location far away from load centres. This is a huge driver for grid investments. Using a probabilistic reliability criterion can significantly reduce the socio economic cost of this integration by finding the optimal balance between investment cost and reliability of the power system • **Balancing costs and reliability** There is a need for a better balance between costs and reliability, maximizing social welfare. A general assumption (as stated in the workshop and the questionnaire) is that N-1 is too expensive. The N-1 criterion does not give answers to which investments, network configurations	• **Data** Getting sufficient and accurate reliability data for analyses in risk based system operation and planning is a challenge. This is a shared opinion in the industry experience (as shown by the questionnaire results) and in the research community. On the other hand, data could also be considered as a driver since TSOs already collect data. • **Modelling of consequences of contingencies** Challenges in calculating consequences as mentioned by TSOs in the questionnaire and identified in the literature. On the other hand, numerous methods and approaches exist, being continuously under development in the research community. Still there is a lack of appropriate and practical tools. • **Transparency and understanding of reliability indices** Deterministic analysis with N-k criteria is easy to understand and explain. The analysis process and the results are transparent. Probabilistic reliability indices are more difficult to understand and explain, have several complex contributing factors and it can be difficult to select which information (indices) to base decisions upon.

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Drivers	Barriers
etc., are socio-economically optimal. Moreover, it does not include socio-economic impacts such as effect of high impact low probability events, environmental impact and interruption costs.	• **Methodological limitations** In order to replace the N-1 criterion with probabilistic criteria, there is a need to validate that this would increase the socio-economic benefit of power system operation. At the moment, there is no applicable methodology to demonstrate that the alternative approaches can increase the socio-economic efficiency of electric power systems with respect to the N-1 practice.

It is interesting to note that the need for probabilistic methods and relating economics and reliability, has been acknowledged for many decades, as pointed out in the introduction to the textbook 'Reliability evaluation of power systems' (Billinton and Allan 1996), which is in use all over the world. The following quotation shows that more or less the same drivers and barriers mentioned in 1996 are still relevant:

> "System behavior is stochastic in nature, and therefore it is logical to consider that the assessment of such systems should be based on techniques that respond to this behavior (i.e., probabilistic techniques). This has been acknowledged since the 1930s [2-5], and there has been a wealth of publications dealing with the development of models, techniques, and applications of reliability assessment of power systems [6-11]. It remains a fact, however, that most of the present planning, design, and operational criteria are based on deterministic techniques. These have been used by utilities for decades, and it can be, and is, argued that they have served the industry extremely well in the past. However, the justification for using a probabilistic approach is that it instills more objective assessments into the decision-making process.
>
> … The main reasons cited for this situation are lack of data, limitation of computational resources, lack of realistic reliability techniques, aversion to the use of probabilistic techniques, and a misunderstanding of the significance and meaning of probabilistic criteria and risk indices. These reasons are not valid today since most utilities have valid and applicable data, reliability evaluation techniques are very developed, and most engineers have a working understanding of probabilistic techniques. It is our intention in this book to illustrate the development of reliability evaluation techniques suitable for power system applications and to explain the significance of the various reliability indices that can be evaluated. This book clearly illustrates that there is no need to constrain artificially the inherent probabilistic or stochastic nature of a power system into a deterministic domain despite the fact that such a domain may feel more comfortable and secure."

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7 DISCUSSION

The contribution of this second deliverable in the GARPUR project is a description of the current TSO practices in and outside of Europe, including common rules that dictate current practices considering the multi-area and multi-agent nature of the power system in the European context, and identification of the main drivers for and barriers against new reliability standards. The GARPUR work that continues after the publication of this report should take into account the recognised drivers and barriers and develop methods that enable the realization of benefits resulting from the drivers and seek to overcome the barriers. GARPUR should aim at bridging the gap between existing practice and future needs.

TSOs recognise *more efficient grid use* and hence *more capacity to the market* as an important driver for probabilistic methods. This becomes an even more important driver when interconnecting large shares of variable renewables into the system, especially when the generation is far away from the consumption and the need for transmission capacity increases.

When transmission capacities that are released to the market are too limited, more lines have to be built in order to transmit the power. Using probabilistic methods to balance the reliability with costs will in principle enable higher utilisation of grid capacities and lead to a more socio economically optimal level of grid investments.

The N-1 criterion does not give *an estimate of reliability* and the resulting reliability varies according to the variations in fault frequencies and consequences of contingencies. In principle, probabilistic methods provide this information, enabling TSOs to use estimated reliability levels to support investment decisions. According to the questionnaire and workshop, the TSOs admit that being able to estimate reliability is an advantage.

The TSOs state that probabilistic methods are complex and difficult to understand. The TSOs are responsible for the system reliability and they have to justify their actions to society, which means that they have to understand and trust the methods they use and 'black box' methods are not acceptable. For GARPUR, this means that the developed methods and tools should be understandable, well described and it is necessary that the results can be evaluated and understood. It is important to realise that there is a long way before TSOs and the society to get used to using probabilistic reliability simulations as decision support. The results from Norway and North America indicate that it is possible, and continuously comparing reliability simulation results with actual system performance would help building up trust over time. It is likely that probabilistic reliability methods in practice must be supplemented by deterministic methods for a long period still.

During the last decades there has been extensive development of probabilistic methods and tools, and computational capacity has increased significantly due to better computers and more advanced algorithms. However, TSOs claim that the probabilistic methods are not mature and there are not applicable tools for systems with meshed grids of real size. They also claim that modelling the consequences (in terms of load shed, duration and cost) is difficult. Different methods for modelling consequences can give quite different reliability results. However, very advanced consequence modelling is complicated and time consuming, and not necessarily feasible in the context of simulating reliability, where the number of situations is high. One challenge for the GARPUR project is to develop methods that are sufficiently mature and advanced to be used for real systems and that consequences and costs are among the results. Finding precise ways of estimating consequences without spending too much calculation time would be a particularly useful step towards bridging the gap between theory and practice.

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An important aspect is data, its availability, its accuracy, and the trust in data[20]. This includes both reliability data and data of variable generation. Naturally, the TSOs have data of their own systems but this may not be sufficient for applying probabilistic methods. According to the questionnaire, the TSOs are willing to share the data between each other. This attitude enables a larger data base than a single TSO can achieve alone. Trusting statistical data always requires a good description of how the data is gathered and what it presents. Consequently, sharing the data publicly is a possible way, like it is done by the Nordic TSOs and NERC.

Decision makers – also TSOs – need to have accurate estimates of the consequences of their decisions. With regard to decision support from probabilistic reliability assessment, estimation accuracy is challenged in three dimensions: The probabilities and consequences of faults and the cost per unit of consequence. One challenge for the GARPUR project is to increase the accuracy on these issues, but it would be even more important to find ways to communicate results so that the level of accuracy is accounted for and it is possible to incorporate this information in the decision making process.

Regulation as it is now is seen as a barrier by some European TSOs. The present regulation relies on N-1. Regulation can be a driver towards probabilistic reliability criteria as examples from Norway and the Netherlands show. Therefore, in the European context, the regulators (ACER) should provide incentives (and rules) to use probabilistic criteria, if these criteria are to be implemented by TSOs in practice.

[20] When answering to Q51, 6 TSOs stated that there would not be sufficient and reliable statistical or other data available for the evaluation.

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8 CONCLUSIONS

ENTSO-E's operational security is based on the N-1 principle, which is a deterministic standard. The performed questionnaire among 9 European TSOs shows that each of the nine respondents conscientiously has implemented the N-1 security principle as specified in the ENTSO-E Policy 3 and adapted it to local conditions. The principle is being used with minor differences for both planning, maintenance and operation.

System operators have analysed disturbances carefully in order to understand causes and possible remedies. As a result, the N-1 principle has continuously been updated with new requirements for the grid planning, and the complexity of the rules and the number of contingencies to be included in the contingency list has increased correspondingly. The present level of reliability of supply is the result of this process.

The background of the widespread international interest for probabilistic methods is the need to achieve a better trade-off between cost and reliability in power systems. The consistent implementation of probabilistic methods in short-term (system operation), mid-term (planning and asset management), and long-term (system development) is however, a considerable challenge. The advantages and disadvantages deserve careful consideration. The international observations indicate that deterministic criteria still are the main tools in planning and operation of power systems.

The North American Electric Reliability Corporation, NERC, has prepared probabilistic tools in North America for several year and reported interesting progress. Even though the requirements of the current NERC Reliability Standards are deterministic, NERC presents guidelines for probabilistic reliability assessment. At the moment probabilistic tools are more widely used for the assessment of generation adequacy. Transmission adequacy is generally assessed using deterministic methods but some companies already have used probabilistic transmission adequacy methods (NERC 2013s, p. 33).

The following elements are central in NERC's preparations of probabilistic planning:

- Availability data has been collected from each of the 26 North American assessment areas for all essential grid elements over a suitable period. NERC is developing comprehensive data systems for estimating the availability of generation, transmission and demand response. The aggregated results are publicly available.
- Regional and local participants in the reliability work must have accurate power system models for the analysis of contingencies for their respective responsibility areas.
- For the calibration of the data and models, system performance has been observed over a suitable period. The results are regularly published.

One possible way to go further on the European level would be that ENTSO-E start to analyse disturbances systematically, including component failures, failure causes and consequences in terms of interruptions and energy not supplied, like it is already being done at the Nordic level. This will lay the foundation for providing appropriate reliability data as input to probabilistic methods.

Drivers and barriers for a new probabilistic reliability framework have been identified based on a questionnaire, workshop answers and literature.

The most important drivers identified are more efficient grid use (including a better balance between costs and reliability), more transmission capacity given to the market, getting an estimate for the reliability, and connecting large shares wind or other variable production into the system. Indeed, probabilistic methods should enable achieving these goals.

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The following items have been identified to be barriers: the methods are laborious, complex and take too much time to use, it is challenging to model the consequences of a contingency since there are not sufficient and reliable statistical or other data available for the evaluation. The lack of data is an important issue. The methods need reliability data, data on variable generation as well as data on socio-economic costs. Some of these data are available, but access to data, sharing and publishing data, as well as the accuracy of data are issues that need to be solved. Finally, there is a reluctance of change and little experience so far. These barriers mean that the probabilistic methods should be implementable, understandable and possible to justify to the society. To achieve the latter, it is necessary to develop a methodology to evaluate the socio-economic benefit of probabilistic reliability criteria compared to the N-1 criterion.

Regulation can be seen as a barrier as stated by TSOs in the questionnaire. However, regulation can also be seen as a driver towards probabilistic reliability criteria as examples from Norway and the Netherlands show. Therefore in the European context, the regulators (ACER) should provide incentives (and rules) to use probabilistic criteria, if these criteria are to be implemented by TSOs in practice.

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APPENDIX 1 QUESTIONNAIRE: RELIABILITY MANAGEMENT IN PRACTICE

Part I Current reliability management

Please comment on differences in planning, operation and asset management in questions where relevant. Multiple choices are allowed.

Q1. How do you define the N-1 criterion?	Please define/specify (for each of the three time horizons planning, operation and asset management):
a) for the intact grid?	
b) for a planned outage?	
c) for an unplanned outage (such as a permanent line fault)?	
Comments/remarks:	

Q2. How do you define the N-2 criterion?	Please define/specify (for each of the three time horizons planning, operation and asset management):
a) for the intact grid?	
b) for a planned outage?	
c) for an unplanned outage (such as a permanent line fault)?	
Comments/remarks:	

Q3. Do you follow the N – 1 criterion strictly?	☐ Yes ☐ No
Comments/remarks:	

Q4. Do you sometimes use weaker/stronger criteria?	☐ Yes ☐ No If yes, please describe.
Comments/remarks:	

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Q5. How do you take into account planned outages if you use the N – 1 criterion for the intact grid?	1 ☐ The grid is operated with N – 0 principle 2 ☐ The grid is planned in such a way that during a planned outage, the N – 1 criterion can be used in the operation in a similar way as when the grid is intact 3 ☐ Varies according to the case, such as location, duration of the outage, timing of the outage, load type, severity of the consequences (please specify) 4 ☐ Other (please specify)
Comments/remarks:	

Q6. Do you have different reliability requirements for different areas, for example for a major city vs. a rural area?	☐ Yes ☐ No If yes, please answer the following alternatives
	1 ☐ Important cities have higher reliability requirements 2 ☐ Important industry has higher reliability requirements 3 ☐ Critical societal functions or infrastructures have higher reliability requirements 4 ☐ Other (please specify)
Comments/remarks:	

Q7. What kind of faults are included in the N-1 criterion as N – 1 faults?	1 ☐ Single line faults 2 ☐ Double line faults 3 ☐ Busbar faults without generators connected 4 ☐ Busbar faults with generators connected 5 ☐ HVDC connection faults 6 ☐ Generator faults 7 ☐ Transformer faults 8 ☐ Other (please specify)
Comments/remarks:	

Q8. If you have double lines in your grid (two lines on the same towers, or two cables in the same ditch) and apply the N – 1 principle: Which is the N – 1 fault here?	1 ☐ Fault and trip of one line/cable 2 ☐ Fault (on one or two lines/cables) and the trip of two lines/cables 3 ☐ Varies according to the case (please specify) 4 ☐ Other (please specify)
Comments/remarks:	

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In answering the following question, please have the intact grid situation in mind. If there are big differences between intact grid and outage situations, please comment. Multiple choices are allowed.

Q9. Which limiting factors after N – 1 faults in the intact grid set the limits for the transmission capacity?	1 ☐ Thermal overloading of lines 2 ☐ Thermal overloading of other components (than lines) 3 ☐ Slow voltage instability (Several minutes or more) 4 ☐ Fast voltage instability (from seconds to some minutes) 5 ☐ Transient voltage instability (instantaneous cascading due to voltage instability) 6 ☐ Transient angle instability 7 ☐ Frequency instability 8 ☐ Damping of electromechanical oscillations 9 ☐ Short circuit currents 10 ☐ Other (please specify)
Comments/remarks:	

Q10. In which cases is the N – 1 criterion not fulfilled in your system? (The list is taken directly from ENTSO-E operational security code as it was 17 Oct 2013)	1 ☐ During switching sequences, 2 ☐ as long as the consequences are local, 3 ☐ during the time period required to activate the Remedial Actions. 4 ☐ Other (please specify)
Comments/remarks:	

Q11. a) Have you experienced or do you foresee cases when the N – 1 criterion is *not* sufficient to secure the electricity supply?	☐ Yes ☐ No If yes, please answer the following questions.
b) In what kind of circumstances do you consider the N – 1 criterion is insufficient?	1 ☐ During severe weather conditions 2 ☐ Varies according to the case, i.e. location, timing, load type (please specify) 3 ☐ Where there are long repair times, example for sea cables (not interconnectors) 4 ☐ Other (please specify)
c) If you find the N – 1 criterion is insufficient what do you do?	Please describe
Comments/remarks:	

Q12. Have you estimated the costs and benefits of applying the N – 1 criterion compared to other reliability criteria?	☐ Yes ☐ No If yes, please describe.
Comments/remarks:	

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For the following question, please remember to consider the highest voltage levels (220 kV and above) and concentrate on power transmission components such as lines and cables. A rough estimate is adequate.

Q13. For how long periods (in %) of the year is your grid not intact, i.e., one of the following components are on outage (planned or unplanned), on average per year	1 ☐ Overhead line ..... % 2 ☐ Underground cable ..... % 3 ☐ HVDC link ..... % 4 ☐ Other (please specify) ..... %
Comments/remarks:	

Q14. How large a share of your grid do the following types of lines/cables amount to?	1 ☐ Overhead single lines ..... % 2 ☐ overhead double lines ..... % 3 ☐ underground cables ..... % 4 ☐ submarine cables ..... % 5 ☐ Others (please specify) ..... %
Comments/remarks:	

Q15. Do you include varying repair times of different components in your N − 1 interpretation (related to how detailed do you perform the consequence evaluation)?	☐ Yes ☐ No If yes, please answer the following question (Q16).
Comments/remarks:	

Q16. How do you include varying repair times of different components in your N − 1 interpretation?	1 ☐ Depends on the importance of the component 2 ☐ Depends on the duration of the repair time 3 ☐ Depends on the type and characteristic of the component 4 ☐ Depends on the costs of the outage (please specify) 5 ☐ Other (please specify)
Comments/remarks:	

Q17. Do you include probabilities in your interpretations of the N − 1 criterion, such as, ignoring some very rare faults.	☐ Yes ☐ No If yes, please answer the following question (Q18).
Comments/remarks:	

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Q18. What kind of probability considerations do you take in the N – 1 criterion?	1 ☐ After very rare faults, the consequences can be different than after normal and frequent faults 2 ☐ Grid fault frequency is taken into account 3 ☐ What else? 4 ☐ Other (please specify)
Comments/remarks:	

By using the N-1 criterion, the consequences after a single fault are regarded acceptable. In the following question we investigate cases where this is too restrictive. Please interpret "using the N-0 criterion" as accepting more severe consequences after certain faults.

Q19. Do you sometimes apply the N – 0 criterion, as defined above?	☐ Yes ☐ No If yes, please answer the following questions.
a. When do you apply the N – 0 criterion?	1 ☐ During a certain period 2 ☐ During a fixed duration (e.g. a certain percentage of time) 3 ☐ During planned outages 4 ☐ In some areas (please specify) 5 ☐ Other (please specify)
b. When applying the N – 0 criterion, do you take into account the ambient situation (temperate, wind, other weather or something else).	☐ Yes ☐ No If yes, please define the criteria.
c. Why do you apply the N – 0 criterion?	1 ☐ The probability of a fault is small, i.e., you accept the risk 2 ☐ To use the grid more efficiently 3 ☐ The transmission capacity given to the market would be too small 4 ☐ It is too expensive to apply the N – 1 criterion (for example when connecting wind power to the grid it would be too expensive to build an additional connection for the rated power of the wind power plant). 5 ☐ Other (please specify)
d. Which are the acceptable situations when you apply the N – 0 criterion?	1 ☐ Varies according to the case, i.e. location, timing, load type (please specify) 2 ☐ Low load situation (For instance in summer time or night time) 3 ☐ The duration of the N – 0 situation is short 4 ☐ No risks for personal safety 5 ☐ After a fault there is overload that is acceptable for a short duration, e.g. 20 minutes, during which the necessary remedial actions can be done. 6 ☐ The alternative would be to shed load 7 ☐ Other (please specify)

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e. When applying the N – 0 criterion, how do you evaluate the probability of a fault?	1 ☐ We use the same statistics as always 2 ☐ We have different probabilities (if yes, please specify) 3 ☐ Varies according to the case, i.e. location, timing, load type (please specify) 4 ☐ Other (please specify)
f. Which are the acceptable consequences when you apply the N – 0 criterion and there is a fault?	1 ☐ Load shedding for some loads regardless of the duration 2 ☐ Load shedding for some loads for a short duration 3 ☐ Varies according to the case, i.e. location, timing, load type (please specify) 4 ☐ A blackout 5 ☐ The consequences of a fault are limited to a small number of customers or a local area, i.e. you accept the risk 6 ☐ The consequences are local and limited and can be handled (e.g. overloading of a line, which has overloading capacity for a fixed duration). Please define the criteria (e.g. the maximum permitted overloading) 7 ☐ No cascading trips as a consequence 8 ☐ Other (please specify)
Comments/remarks:	

Q20. When planning the grid, do you…	1 ☐ Take into account the repair time of components (or time to restore electricity to customers that are (partly) interrupted)? 2 ☐ Take into account the type of load, for example do you interpret the N - X criterion differently for industrial load and domestic load? 3 ☐ Use system protection schemes for mitigating the consequences? 4 ☐ Plan re-dispatching for mitigating the consequences of a fault? 5 ☐ Other (please specify)
Comments/remarks:	

Q21. When operating the grid, do you…	1 ☐ Take into account the repair time of components (or time to restore electricity to customers that are (partly) interrupted)? 2 ☐ Take into account the type of load, for example do you interpret the N - X criterion differently for industrial load and domestic load? 3 ☐ Use system protection schemes for mitigating the consequences? 4 ☐ Use system protection schemes for increasing the transmission capacity? 5 ☐ Plan re-dispatching for mitigating the consequences of a fault? 6 ☐ Other (please specify)
Comments/remarks:	

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Q22. When operating the grid during maintenance work, do you…	1 ☐ Take into account the repair time of components (or time to restore electricity to customers that are (partly) interrupted)? 2 ☐ Take into account the type of load, for example do you interpret the N - X criterion differently for industrial load and domestic load? 3 ☐ Use system protection schemes for mitigating the consequences? 4 ☐ Plan re-dispatching for mitigating the consequences of a fault? 5 ☐ Other (please specify)
Comments/remarks:	

The following question is important to see how you evaluate grid investments and operations today. Multiple choices are allowed.

Q23. How do you include socio-economic benefits and costs in the transmission system today? (Please comment on differences in planning and operation)	<u>Benefits</u>: 1 ☐ Increased transmission capacity 2 ☐ Reduced expected loss of load (expected interruption costs) 3 ☐ Increased security margins 4 ☐ Other (please specify) <u>Costs</u>: 5 ☐ Congestion costs 6 ☐ Expected interruption costs 7 ☐ Costs of reserves 8 ☐ Re-dispatch costs 9 ☐ Outages that lead to high electricity market prices in some areas 10 ☐ Other (please specify)
Comments/remarks:	

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Part II Reliability methods, tools and data in use

II.1 Reliability methods in use (incl. socio-economic impact assessment)

Multiple choices are allowed.

Q24. Which methods are used to assess the reliability of planned grid developments?	1 ☐ Power flow analysis 2 ☐ Dynamic analysis 3 ☐ Reliability analysis including probabilities (or frequencies) of failures and consequences (please specify) 4 ☐ Short circuit analysis 5 ☐ Other (please specify)
Comments/remarks:	

Q25. Which methods are used to assess the operational reliability?	1 ☐ Power flow analysis 2 ☐ Dynamic analysis 3 ☐ Reliability analysis including probabilities (or frequencies) of failures and consequences (please specify) 4 ☐ Short circuit analysis 5 ☐ Other (please specify)
Comments/remarks:	

Q26. Which methods are used for mid-term planning (asset management?	1 ☐ Reliability-centred maintenance (RCM) 2 ☐ Failure mode and effect analysis (FMEA) 3 ☐ Reliability analysis including probabilities (or frequencies) of failures and consequences (please specify) 4 ☐ Other (please specify)
Comments/remarks:	

Q27. Do you also assess the socio-economic impacts for the above mentioned time horizons?	1 ☐ In planning of grid developments 2 ☐ In operational planning 3 ☐ In online operation 4 ☐ In asset management If yes, please specify the methodology in use time for each time horizon.
Comments/remarks:	

Please comment on differences in planning, operation and asset management in questions where relevant.

Q28. How do you model or take into consideration the probabilities of external threats (e.g. weather, human errors etc.) and the actual consequences of interruptions to the loads (customers)	Please describe:
Comments/remarks:	

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Q29. How do you model or take into consideration corrective control (remedial actions) and its probability of failure?	Please describe:
Comments/remarks:	

Q30. How do you model or take into consideration demand side management and energy storage?	Please describe:
Comments/remarks:	

Q31. How do you model or take into consideration low-probability high-impact events?	Please describe:
Comments/remarks:	

Q32. Are there any areas you feel the existing methodologies fail to cover?	☐ Yes ☐ No If yes, please specify.
Comments/remarks:	

II.2 Software tools in use

Multiple choices are allowed.

Q33. Which software tools are used to assess the reliability of planned grid developments? Please provide name of tools.	1 ☐ In-house developed software (one or more, in Matlab, Excel or other) 2 ☐ Commercial or external software (one or more, please specify) 3 ☐ Other (please specify)
Comments/remarks:	

Q34. Which software tools are used to assess operational reliability? Please provide name of tools.	1 ☐ In-house developed software (one or more, in Matlab, Excel or other) 2 ☐ Commercial or external software (one or more, please specify) 3 ☐ Other (please specify)
Comments/remarks:	

Q35. Which software tools are used for mid-term planning (asset management)? Please provide name of tools.	1 ☐ In-house developed software (one or more, in Matlab, Excel or other) 2 ☐ Commercial or external software (one or more, please specify) 3 ☐ Other (please specify)
Comments/remarks:	

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Q36. Which software tools are used for socio-economic impact assessment? Please provide name of tools.	1 ☐ Same tool as for reliability assessment (please specify 2 ☐ In-house developed software (one or more, in Matlab, Excel or other) 3 ☐ Commercial or external software (one or more, please specify) 4 ☐ Other (please specify)
Comments/remarks:	

Q37. Are there any areas you feel the software tools fail to cover?	☐ Yes ☐ No If yes, please specify.
Comments/remarks:	

II.3 Reliability metrics/indicators in use

Multiple choices are allowed.

Q38. Which metrics/indicators are used to assess the effect of planned grid developments on the system reliability?	1 ☐ Load point indices 2 ☐ Bulk power system indices 3 ☐ Annual number of interruptions 4 ☐ Annual interruption duration 5 ☐ Average interruption duration 6 ☐ Annual interrupted power 7 ☐ Annual energy not supplied 8 ☐ Annual interruption cost (cost of energy not supplied) 9 ☐ Value of lost load 10 ☐ System minutes 11 ☐ Electricity market prices in the system (with or without a certain investment) 12 ☐ Other (please specify) Metrics: .....
Comments/remarks:	

Q39. Which metrics/indicators are used to assess operational reliability?	1 ☐ Load point indices (please specify 2 ☐ Severity indices: 3 ☐ Overload (or risk of overload) 4 ☐ Voltage deviations (or risk of voltage deviations) 5 ☐ Frequency deviations (or risk of frequency deviations) 6 ☐ Margin to instability (please specify) 7 ☐ Duration of the system being in alert state 8 ☐ Critical fault clearing time 9 ☐ Probability of load curtailment 10 ☐ Other (please specify) Metrics: .....
Comments/remarks:	

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Q40. Are there any aspects you feel the metrics/indicators fail to measure?	☐ Yes ☐ No If yes, please specify.
Comments/remarks:	

II.4 Reliability data and interruption cost data

In this section we investigate collection of reliability data in the TSOs. By this, we mean outage statistics on lines and components, typically registering fault, failure causes and repair times.

Multiple choices are allowed.

Q41. Do you collect the following type of data about faults on components?	1 ☐ Faults 2 ☐ Outage times 3 ☐ Failure causes 4 ☐ Other (please specify)
Comments/remarks:	

Q42. How do you use these data?	1 ☐ System development, grid investment planning 2 ☐ Asset management in general (please specify) 3 ☐ Maintenance planning 4 ☐ Grid performance statistics 5 ☐ Other (please specify)
Comments/remarks:	

Q43. Do you process the data, like calculating…?	1 ☐ Failure frequency 2 ☐ Repair time 3 ☐ Long-term unavailability 4 ☐ Other (please specify)
Comments/remarks:	

Q44. For which components do you collect and process reliability data (number of faults, fault causes, repair time)?	1 ☐ Overhead lines 2 ☐ Cables 3 ☐ Busbars 4 ☐ Generators 5 ☐ Transformers 6 ☐ HVDC lines 7 ☐ Circuit breakers 8 ☐ Protection system 9 ☐ System failures such as under-frequency situations, islanding 10 ☐ Other (please specify)
Comments/remarks:	

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Q45. What kind of data do you use when you perform socio-economic impact assessment in planning or operation (in relation to the reliability assessment, i.e. estimate VOLL, CENS or other)?	1 ☐ Cost rates for different customer groups (please specify) 2 ☐ One fixed average cost rate (please specify) 3 ☐ Cost rates as a function of interruption duration 4 ☐ Cost rates as a function of time of day, day of week, season 5 ☐ Other (please specify)
Comments/remarks:	

Q46. Are you willing to share data with other TSOs?	☐ Yes ☐ No
Comments/remarks:	

Q47. Do you collect data about human errors (e.g. when somebody is working at a substation or at a line)?	☐ Yes ☐ No If yes, please specify
Comments/remarks:	

Q48. Do you collect data of faults on corrective control measures (remedial actions)?	☐ Yes ☐ No If yes, please specify
Comments/remarks:	

Q49. Do you collect real time information (from PMUs and other) for reliability assessment?	☐ Yes ☐ No If yes, please answer the following questions
a. Is PMU applied in detecting unstable voltage situations?	☐ Yes ☐ No
b. At which voltage levels is PMU applied?	1 ☐ 220 kV and above 2 ☐ 132 - 150 kV 3 ☐ 50 - 60 kV 4 ☐ Other (please specify)
c. Are the PMU measurements aggregated in one or more data concentrators?	☐ Yes ☐ No
d. For how long time is the PMU measurements archived in full resolution?	1 ☐ one month 2 ☐ two months 3 ☐ three months 4 ☐ Other (please specify)

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e. Which time normal is applied for the PMU in your grid system?	Please specify:
Comments/remarks:	

IV. Drivers and barriers

In this section we are asking for your opinion. Multiple choices are allowed.

Q50. If the reliability criterion is changed from N-1 to one that in some way considers the probability and consequences of contingencies would you achieve one or more of the following benefits?	1 ..... More efficient grid use 2 ..... More transmission capacity given to the market 3 ..... Less capacity given to the reserves and more capacity to power transmission 4 ..... Probabilistic methods would enable an estimate of the reliability 5 ..... Increase in wind or other variable production 6 ..... Other (please specify) Please rank the alternatives you have chosen:
Comments/remarks:	

Q51. Which factors will prevent or act as barriers to introducing a reliability criterion that in some way considers the probability and consequences of contingencies instead of the strict N-1?	1 ☐ Applying the method/tools would be too laborious 2 ☐ Applying the method/tools would take too much time 3 ☐ There would not be sufficient and reliable statistical or other data available for the evaluation 4 ☐ It would be difficult to understand and justify to society 5 ☐ Regulation requirements 6 ☐ The uncertainty of the acceptable and non-acceptable consequences would increase 7 ☐ Other (please specify)
Comments/remarks:	

Q52. Do you think that it would be useful or important to assess the reliability level taking the probability and consequences of contingencies into account?	☐ Yes ☐ No If yes, please specify.
Comments/remarks:	

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APPENDIX 2 VIEWS ON GRID RELIABILITY STANDARDS FROM THE REPORT BY STRBAC AND DJAPIC

A peer review to the New Zealand Security and Reliability Council by Strbac and Djapic (Strbac and Djapic 2008) discusses the shortcomings of the traditional deterministic planning and the potential and challenges of probabilistic planning. Some selected views from the report are given in the following. Driving factors for changes in approaches to network planning (Strbac and Djapic 2008, p. 5):

- Need to incorporate non-conventional generation, such as wind power;
- Need to demonstrate that investments in monopoly functions are efficient and deliver the best value for consumers and
- Need to ensure that network planning and operational standards do not impose unnecessary barriers to entry and do not prevent timely connection of new generating plant and demand.

Issues with deterministic standards:

- The deterministic criteria in grid planning and operation have been gradually developed since the 1950’s. Analyses of blackouts and other serious events have given rise to updates and extensions of the criteria (Strbac and Djapic 2008, p. 12).
- There is no close alignment between transmission project costs with expected economic benefits; the deterministic standards are unable to reflect the levels of risk that the power system consumers actually face and hence cannot be used to assess network investment efficiency (Strbac and Djapic 2008, p. 6).
- Deterministic standards will always produce a non-optimal solution. A deterministic standard is likely to lead to overinvestment in cases of supplying relatively small demand that is located away from generation and underinvestment in cases of relatively larger demand that is located relatively close to generation. (Strbac and Djapic 2008, p. 6–7)
- Deterministic standards do not consider the likelihood of network component outages. Outages rates are different for different components and in many cases strongly depending on weather. (Strbac and Djapic 2008, p. 6)

The change from deterministic to probabilistic planning standards:

- Change from the historical deterministic approach to transmission investment to a probabilistic cost-benefit framework may have a wide-ranging impact on the over-all philosophy and development of transmission operation and planning processes in future. (Strbac and Djapic 2008, p. 17–18)
- In particular a transition from the historical deterministic practice of providing net-work capacity and flexibility mostly via investment in network primary assets, to-wards a new paradigm where a much wider range of options is considered (including the application of non-network solutions; the development of advanced maintenance practices; the introduction of more sophisticated network protection; and system operation and control practices). (Strbac and Djapic 2008, p. 17–18)
- Probabilistic standards quantify the economic benefit of reducing risk of interruptions due to investment and conceptually explicitly and accurately reflect the level of operational risk and provide a framework for network and non-network solutions comparison (Strbac and Djapic 2008, p. 6).

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Data and modelling (Strbac and Djapic 2008, p. 7)

- The evaluation of reliability benefits for alternative network reinforcement options over time requires *forecasts* of growth in demand, including its temporal and spatial distribution and forecasts of generation capacity, including its temporal and geographical distribution as well as its technical characteristics.
- Stochastic data is required for the *failure rates* of various network assets and generating units (including common mode failures where relevant), repair times, protection and control system behaviour.
- An important parameter that will have a potentially significant impact on the performance of the network reinforcement options considered is the *value of lost load* (VOLL).
- Analysis and derivation of figures of VoLL suggests that the numerical value of this parameter is very dependent on the *duration of interruptions*, ranging from relatively high values for short-term interruptions to relatively low values for long-term interruptions.
- In order to ensure that a robust solution is identified among available alternatives, given the uncertainly of input data, it is essential to determine the extent to which each of the critical input parameters can vary before the solution changes.
- Two modelling approaches are considered. The Frequency-Duration (FD) method is particularly suitable for the consideration of relatively small areas. Monte Carlo based reliability approaches generally offer a higher degree of flexibility and the ability to consider a wider range of uncertainties.

Blackouts and High Impact Low Probability events (HILP) (Strbac and Djapic 2008, p. 9)

- Many recent power system blackouts were triggered by a credible contingency whose effect was compounded by an internal failure that often involved a protection malfunction.
- It is interesting that the lack of investment in the primary transmission infrastructure has not been specifically identified as a cause of the major blackouts. In a number of cases, this was explicitly excluded as a cause of failures (e.g. Tokyo 1987, WSCC 1996, Brazil 1999, UK 2003, North America 2003, Sweden 2003, UCTE 2007).
- A probabilistic standard provides a natural framework for including effects of High Impact Low Probability events (HILP) events on the network design.
- The consequences of HILP event may be possible to assess for given causes and expected actions to be taken to remedy the situation. However, the likelihood and probability distribution of HILP events is very difficult to estimate given the sparse data.

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APPENDIX 3 ANSWERS FROM THE GARPUR TSO WORKSHOP

This appendix presents the answers given by TSOs participating at the GARPUR Workshop on 7 April 2014. The task given to the TSOs was to list possible drivers and barriers of a new probability reliability framework. The classification of answers is done by the authors of this document and not by the TSOs.

DRIVERS

More efficient grid use

-"General assumption that N-1 is extremely expensive"
-"Better balance between costs and reliability"
-"Analyse/describe/differentiate between conditions that are [or not] N-1 secure (but may still be very different in terms of cost and/or security)"
-"Non-economic to have assets loaded to only 50 % 98 % of the time"
-"Prevent huge investments in grid"
-"Difficult to build new infrastructure"
-"N-1 does not give an answer to what network configuration is economically better"
-"To avoid (large) investments with (very) low utilization"
-"Increase grid utilization"
-"And in the end to do a better job in maximizing social welfare, accommodating more RES, etc…"
-"Maximise use of assets"
-"Increase performance of grid/efficiency"
-"Better use of existing infrastructure"
-"Less investments needed"
-"Avoid 'overshooting' prudence"
-"There are cases when N-1 criterion is too restrictive regarding the consequences of its application (for example more than one line on a tower)"
-"Save money on investments"
-"Cost reduction"
-"Efficiency of costs"
-"Need for better cost optimization"
-"Reduce investment and maintenance costs"
-"Investment on new infrastructure saving today's and future needs is not possible because: Investment cannot be made 'money-wise', investment cannot be made because of right of way"

More transmission capacity given to the market

-"Rapidly available of additional transmission capacity"
-"Provide more transmission capacity"
-"There are cases when N-1 criterion is too restrictive regarding the consequences of its application (for example more than one line on a tower)"
-"Pressure from the market in a system with increasing load level and delay in investments → N-1 is limiting and creating unnecessary costs for society"

Probabilistic methods would enable an estimate of the reliability

-"Analyse/describe/differentiate between conditions that are [or not] N-1 secure (but may still be very different in terms of cost and/or security).
-"To be able to document your risk attitude"
-"Avoid 'overshooting' prudence"
-"To provide more (and better information to make decisions. Especially about the risk level (i.e. whether you use N-1 or what ever criterion)"
-"Better indication of actual operational security"

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Increase in wind or other variable production
-“RES integration”
-“And in the end to do a better job in maximizing social welfare, accommodating more RES, etc…”
-“RES (variable gen.)”
-“System vision, integrating demand, DSO, storage, generators, market”
-“Renewable deployment: the cost of a line linking a wind farm to the pan European transmission network (working less than 3000 hours/year): N-1 requires probably those identified lines (including the one for maintenance)"
-"Low cost RES on critical equipment which allow real time management of “health status” of the equipment: increased capacity and feasibility”

Other answers
-“Lack of infrastructure of IT resources to accomplish N-1”
- “N-1 is already at certain times overruled → need for a accepted method with more accuracy”
-“Push from customers/stakeholders/politics to push reliability to the limit to keep tariffs low – ind. Re-dispatch – and unforce taking risks”
-“Phase out of large generators (nuclear)”
-“Open market → add extra uncertainties physic flow + money flow”
-“Demand-side response: EV, heat pump,…”
-“N-1 does not take into account for example which elements have more faults or which elements are younger/older (tend to have more problems). This no indication on what to improve.”
-“The volume of the bigger unit in comparison with the size of the grid”
-“Aging assets”
-“Other changes in system”
-“The probability of an outage has an impact on the evaluation of the reliability (for example the outage of a transformer is not as probable as the outage of a line)”
-“Need for higher power system flexibility”
-“Large changes in power systems in the future”

BARRIERS
Complexity of the computations
-“Very complex computations”
-“Complex mathematical description and complex methodology for solution”
-“Complexity of f.c. probabilistic modelling → high computation time”
-“Calculations using complex criteria are time-consuming to do”
-“Too complicated in real-time application”
-“The simplicity of N-1 is very intuitive and very hard to find out similar basic method. Everything has to be more complex”

Lack of methods
-“Unavailability of tools”
-“Non-existence of applicable, unified tools”
-“Lack of proven methodology”
-“Find a practical way to calculate the indexes in different time spans (plan, asset, operation)”

Laborious transition
-“Criteria other than N-1 would take much effort to implement: collect data, train people, recognize workflows and practices, change planning software (maybe)”
-“Current TSO workforce (e.g. operation) is not ready for radical or dramatic changes”
-“Difficulty to understand and explain methods so the operational people trust them”

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Reluctance of change
-“Why change a functioning criterion, N-1, to something different?”
-“’Business as usual’ practices”
-“Fear of changing a simple way to handle risk management”
-“Fear of implementing a more complex (segmented!) way of addressing risk management”
-“N-1 is simple enough and convenient to use”
-“N-1 feels so secure and comfortable”
-“Unwillingness (I suppose) of operators to think out of the box and experiment and accept new methodologies and tools.”
-“Cultural issues, attitudes, resistance of change”

There would not be sufficient and reliable statistical or other data available for the evaluation
-“Data availability”
-“Lack of trust in data (probabilities and costs)”
-“Lack of accuracy of data/methods (for instance: what is actually the consequence of a contingency?)”
-“Back testing not possible/easy (lack of outage observations)”
-“Lack of appropriate input data”
-“The lack of accurate data for probability of failure”
-“Lack of information”

It would be difficult justify to society
-“Acceptance by traditional operations managers”
-“Risk discussion will not be solved between stakeholders: regulator, customers, operators, investors”
-“Customer’s awareness of reliability”
-“Lack of confidence (acceptance by the user)”
-“Not understanding by decision makers (politicians, regulator, TSO-board)”
-“Public acceptance of risk of power system failures”
-“Unknown risks”

Regulation requirements
-“Acceptation by the regulator”
-“Regulation”

No experience so far
-“Not enough evidence for the risk level of new approach → Who takes risks first”
-“First-in-class i.e. no pioneer!”
-“Lack of standards /track records (from peers)”
-“Lack of own experience”
-“The new alternative methodologies haven’t been proven in practice”

Other barriers
-“Reliability costs are not well identified neither considered”
-“Electricity is more and more relevant in EU society”
-“Relying on corrective actions”
-“Uncertainties in forecasting”
-“Blackout part of system”
-“Unclear link between probability of failures and cost for the society of a failure”
-“Financial crisis → constraint for extra investment”
-“Lead time (construction time) of new lines. We have to start early, and must avoid an urgent problem (large congestion, for a longer period)”

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-“Higher losses in the grid”
-“Find a way to estimate the balance between reliability and economy (social) costs”
-“What is the minimum security level acceptable by society”
-“How do deal with environmental aspect”
-“Conservative way of thinking”
-“Uncertain degree of reliability of results from probabilistic reliability analysis”
-“More risks”
-“Changes in the way decisions are taken, from deterministic figures to probabilistic”
-“Black boxes not acceptable for this”
-“Operation staff is well aware on N-1 way of work”
-“Will new method be clear enough”
-“Not as transparent as N-1”
-“Present reliability (N-1) in Europe is outstanding”

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