Reliability and Cost-Benefit-Based Standards for Transmission Network Operation and Design

A thesis submitted to

Imperial College London

For the degree of Doctor of Philosophy

by

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February 2012

Declaration

This is to certify that:

1. The material contained within this thesis is my own work.

2. Other work is appropriately referenced.

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Abstract

The growing interest in decarbonising electricity systems together with advances in communication and information technologies that may support the application of demand and generation solutions to solve network problems has initiated reviews of traditional operational practices and security grid standards in a number of jurisdictions. The key concern is that these historical practices and standards, mostly developed in the 1950's, might be inappropriate for the new emerging systems as they may pose entry barriers for both renewable generation and smart grid technologies. This thesis presents a probabilistic cost-benefit framework for the development of future efficient operating and design strategies and network security standards enabled by new technologies. By optimally balancing the costs of network constraints with various operational measures composed of preventive and corrective control actions, considering potential outages of network and generation facilities, optimal network capacity that could be released to network users in real time is determined along with its impacts on network design. This framework is compatible with smart grid concepts which integrate new generation, network, and demand technology.

Together with the aforementioned framework, a full optimisation model that serves to scrutinise the characteristics of the proposed probabilistic standards in the presence of high penetration of wind is developed by means of a Benders algorithm. To reduce the computational times and memory usage, a novel technique that eliminates redundant scenarios (i.e. outages) that do not contribute towards the optimum solution and hence simplifies the optimisation procedure is presented and successfully tested.

The studies demonstrate that various operational measures (such as generation and demand response) can be effectively used to release additional network capacity with small (or even nil) increases in risk. It is also demonstrated that the GB system would benefit in terms of network investment and congestion costs if the changes proposed were adopted.

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Journal papers:

Moreno, R., Pudjianto, D., Strbac, G., "Integrated Reliability and Cost-Benefit Based Standards for Transmission Network Operation", Proceedings of the Institution of Mechanical Engineers, Part O: Journal of Risk and Reliability, Vol 226, Issue 1, pp. 75-87, 2012.

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“Economic Considerations for the Sustainable Development of the Electric Transmission Network in Chile”, a report elaborated by P. Miquel, S. Mocarquer, R. Moreno, and H. Rudnick for Transelec, Chile, 2010.

"The Impact of Intermittent Generation on Transmission Network Investment", a report elaborated by Imperial College London for DECC, UK, 2009.

"Transmission Access Review: Analysis of Constraint Costs and Strawman Models", a report elaborated by Poyry and Imperial College London for OFGEM, UK, 2008.

Abbreviations

AC	Alternating current
CBA	Cost-benefit analysis
CCGT	Combined cycle gas turbine
CHP	Combined heat and power
DC	Direct current (in this thesis, it refers to HVDC assets)
DG	Distributed generation
DLR	Dynamic line rating
DSM	Demand side management
DR	Demand response
EC	European Commission
EENS	Expected energy not supplied
ENS	Energy not supplied
ENSG	Electricity networks strategy group
FACTS	Flexible alternating current transmission system
GB	Great Britain
HVDC	High voltage direct current
ICG	Shared collector substations (for its name in Portuguese)
LMP	Locational marginal prices
LP	Linear programming
MILP	Mixed integer linear programming
MITS	Main interconnected transmission system
MSG	Minimum stable generation
N-1	Deterministic security policy that refers to single outages
N-2	Deterministic security policy that refers to double outages
O	Operational cost

O+X	Summation of the cost of network operation and expected unsupplied demand / It is also the name of the operational probabilistic model developed
OFGEM	Office of gas and electricity markets
OPF	Optimal power flow
PDF	Probability distribution function
P-OPF	OPF with probabilistic security
SC-OPF	Security constrained OPF
SPS	Special Protection Scheme
SQSS	Security and quality of supply standards
SO	System operator
T	Transmission investment cost
T+O+X	Summation of the cost of network investment, operation and expected unsupplied demand / It is also the name of the investment probabilistic model developed
TSO	Transmission system operator
UK	United Kingdom
VoLL	Value of lost load
X	Expected cost of unsupplied demand

List of symbols

Mathematical symbols are defined in the beginning of each chapter or along the text.

Acknowledgements

Firstly, I would like to acknowledge the unconditional patience and love of the person who has heard me say “O plus X” and “T plus O plus X” on a daily basis, my beloved wife Leslie Lira.

After her, all the rest:

The support and friendship of Goran Strbac and Danny Pudjianto were crucial in the development of this research. A considerable large volume of this work was stimulated from inspiring and fruitful discussions with them.

Thanks to Marcelo Moreno, Hugh Rudnick, Luiz Barroso, Bernardo Bezerra, Christos Vasilakos, Robert Sansom, Juan Carlos Araneda, Alex Sturt and colleagues from Scottish Power, Scottish and Southern Energy and National Grid, in particular Paul Plumptre. All of whom have had their influence on this work through the sharing of knowledge and interesting discussions about future wonderful electric grids and equitable energy markets.

The comments of Lewis Dale and Richard Vinter, two examiners of this thesis, are very much welcome.

Thanks also to the ones that actually distracted me (i.e. help me to relax) from programming and solving optimisation models: Soha, Pierluigi, Jelena, Connie, Daniele, Dimitrios, Makis, Carlos, Vera, Maria, John, David, Yousef, Marcela, Barbara, Alejandro, Wolfram, Luigi, Pablo, Juancho, Ginette, Jorge, Pedro and Claudia.

Most importantly, my thanks and love to Maria, Marcelo and all my brothers’ and sisters’ families.

The financial support of Beca Presidente de la Republica of the Chilean government is very much appreciated.

Dedication

To the ones who dream and fight

CHAPTER 1: Introduction

1.1 Motivation

1.1.1 Need for network investment to integrate renewables

Electricity systems worldwide face challenges of unprecedented proportions. In response to addressing climate change, governments of a number of countries are already committed to the support of renewable and other low carbon generation technologies. Interesting initiatives are:

- The European Commission (EC) directive of March 2008 [1] set a legally binding target of having 20% of the energy consumed in the European Union (EU) coming from renewable energy sources by 2020.
- The 2008 Climate Change Act [2] in the United Kingdom (UK) set legally binding targets to reduce greenhouse gas emissions by 26% by 2020 (when compared to 1990 levels).
- The American Recovery and Reinvestment Act of 2009 [3] included about 70 billion US$ in spending and tax credits related to clean energy.
- An array of developing countries such as China and Brazil [4,5] has already significantly invested in renewable generation.

Furthermore, more radical programmes like the one included in the Climate Change Act [2] in the UK that sets 2050 targets at 80% CO_2 reduction from 1990 levels, are likely to result in significantly increased levels of electricity demand from the incorporation of heat and transport sectors.

To address this challenge, the electricity network will play a key role in facilitating cost-effective integration of large amounts of low carbon technologies. In fact, the need for significant investment in network infrastructure has been already recognized not only by engineers but also by policy makers. For instance in October 2008, the future US president, Barack Obama declared: “One of…the most important infrastructure projects that we need is a whole new electricity grid. Because if we are going to be serious about renewable energy, I want to be able to get wind power from North Dakota to population centres like Chicago”.

Consequently, companies in North America have already identified approximately US$40 billion in transmission investment by 2021 in order to facilitate integration of renewables [6]. For similar reasons, other countries such as the United Kingdom and Spain are currently considering transmission investment plans of about £15 billion (2010-2020) and €4 billion (2010-2014), respectively [5,7]. The European Commission has also recently (2010) allocated €910 million for 12 electricity interconnection projects as part of its European Economic Recovery Plan [5].

The costs above can be sharply escalated if the network investment necessary is considered for the (nearly) total decarbonisation of the energy matrix by 2050. In a European perspective, reports [8, 9] show an investment cost of around €182 billion necessary for the transmission network sector by 2050.

1.1.2 Need for network investment efficiency

In light of the large amount of network infrastructure needed, there is a concern about how network investment is being planned. Furthermore, as this sector has been historically developed under a monopoly structure with conventional thermal generation, there is an increasing need to prove that all the activities related to the network business are now conducted efficiently.

Therefore, the need to facilitate connection and integration of renewables will not only require significant amounts of investment but also fundamental reviews of the overall framework for electricity network operation and investment. These reviews include areas such as network access, network planning and operation, security, and regulation and revenue requirements. In effect, the results of a survey undertaken over three countries (the UK, Brazil and Chile) show an array of changes in transmission arrangements caused by the authority's willingness to introduce renewable generation and ensure that the network sector remains efficient [5]. These changes can be observed in Table 1.1.

Table 1.1: Network infrastructure and arrangements changes for renewables: UK, Brazil and Chile

Network Infrastructure for Renewables	**UK (Transmission)**	**Brazil (Transmission)**	**Chile (Transmission)**
Investment needed (current estimates)	£7-8 billion in the Onshore network. £7-8 billion in the Offshore network. (by 2020 to connect ~11GW of onshore wind, ~19GW of offshore wind and ~3GW of nuclear – source: National Grid Vision).	About US$ 500 million has been needed so far in transmission assets and Shared Collector Substations for generators (ICG) to connect biomass and wind power already auctioned. Billions of dollars will be needed if an aggressive penetration (>15 GW) takes place.	US$3.0 – 6.5 billion in upgrades in the whole transmission system for the 2010 -2020 period. This also takes account of the high demand growth about 5-6%.

Network Arrangement Changes for Renewables	**UK (Transmission)**	**Brazil (Transmission)**	**Chile (Transmission and Distribution)**
Access	Transmission Access Review completed. Change from invest-then-connect to connect-and-manage access arrangement (to provide timely long-term access rights and not to impose short-term cost signals).	Transmission open access policy always in place but now boosted by a special regime that enables renewables' connection though ICGs.	Introduction of distribution open access and rules that regulate DG payments within distribution networks. Toll discounts for renewables in trunk transmission system (open access). Recognition of problems about unfair tolls in new transmission investments.
Planning	Transmission Access and SQSS Review being undertaken. Transmission planning driven by SQSS may be replaced by market driven investment.	Optimisation model developed to integrate renewable through centrally-planned collector substations. Driven by economics criteria.	Central planning scheme modified to recognize special requirements for substations that connect wind power.
Investment philosophy	Regulator approves investment proposals at present. Proposal to introduce anticipatory investment regime to enable speculative network investment prior to users' commitments (i.e. Strategic Investment proposal).	Regulator approves investment proposals made by the Agency for Planning Studies. Transmission construction takes about 18-36 months since rights-of-way are easier to obtain than in dense-populated developed countries. Wind is located closer to consumption centers (along the coast), where transmission is more developed. Anticipatory investment no needed so far.	No changes. The authority approves investment proposals. Transmission expansion based on generation scenarios, including renewables, with no anticipatory investment (generation backgrounds given by committed new generators).
Security	SQSS Review being undertaken. Probabilistic cost-benefit framework considered to replace historical deterministic N-k criteria.	No changes. Security standards are partly based on probabilistic and cost-benefit concepts (N-0, N-1 etc depending on the transmission line), particularly in operational timescales.	No changes. Security standards are partly based on probabilistic and cost-benefit concepts (N-0, N-1 etc depending on the transmission line) in both operation and planning.

Regulation and revenues	RPI-X Review completed to provide additional incentives to TSOs. A more outcome focused approach (RIIO) has now been introduced.	Definition of ICG's cost recovery through fixed rates on investments. Same tariff scheme already in place for network remuneration.	No changes. Cost recovery through fixed rates on investments in transmission and yardstick competition model in distribution.
Network operation technologies	Pressure to increase capacity through advance operational measures. The option to increase investment in smart technologies has been promoted as a potential outcome by companies under RIIO. Smart meters roll out approved, demand side participation expected post 2020.	No changes. Application of advanced intertripping schemes (or SPS) to increase transfer capability of the network already in place.	No changes. Application of intertripping schemes (or SPS) to increase transfer capability of the network already in place.
Network (re)classification	Development of Offshore networks, under offshore network design standards (different from onshore). Whistle onshore network is defined as monopoly, offshore networks are competitive.	Definition of the "shared facilities for generators" (ICG) concept.	No new definitions because of renewables.

The array of changes of network arrangements for renewables shown in Table 1.1 covers from the need to facilitate generation access to the need to define new classifications for particular types of network assets like the offshore transmission. The array of changes also covers the potential need to have a probabilistic approach for security in both network operation and planning, to undertake proactive network investment ahead of users' requests, and to incentivise the integration of new network (and communication) technology by means of an appropriate regulatory scheme.

1.1.3 Network investment efficiency through network security

The rules that determine the level of capacity that is released to network users in real time are codified in the form of security standards. These security standards have been based, in most of the countries, on deterministic operation and design criteria, i.e. electricity transmission networks should be able to withstand a loss of one or two circuits (i.e. N-1 or N-2 deterministic network criteria) without causing overloads of any other circuit and such outages must not threaten the integrity of system operation [10]. For this credible or secure set of faults, demand cannot be shed. In the context of the delivery of large amount of future network investments, it is critical for network users to know how much capacity is available in the transmission network in real time and whether this level of capacity is efficiently determined by the historical deterministic security N-1/N-2 type rules. Hence, a key component of the analysis of new network investment is to evaluate the existing rules by using cost-benefit analyses that include consideration of the appropriate balance between investment costs, operational costs and risks.

Furthermore, given the pressing need for additional transmission capacity to accommodate renewable generation, there is a concern that the existing deterministic network security standards may be a barrier for the application of a range of advanced technically effective and economically efficient non-network solutions. For example, corrective or post-fault actions that can release latent network capacity of the existing network. Rules used to determine the amount of capacity that can be released to network users in real time might be inefficient and limited to the application of asset-heavy network solutions to network problems, i.e. network redundancy. If updated within an improved cost-benefit framework, this would result in lower network constraints costs and facilitate more efficient connection of renewables. It is expected that the levels of transmission capacity that are released to users in operational timescales would vary with the magnitude of constraints costs, probability of outages (e.g. weather conditions), cost of post contingency services, etc. In turn, this could reduce the need for future network investment [11].

In light of these considerations, renewables' entry could be accelerated by substituting requirements for network investment with operational measures supported by information and communication infrastructure, including Special Protection Schemes (SPS), coordinated voltage control techniques, wide-area monitoring and control systems, advanced dynamic security assessment techniques and Demand Response (DR).

1.1.3.1 Specific drivers for a change in security standards

Recently, there have been various debates associated with updates and reviews of network operation and planning standards and practices in a number of jurisdictions. This is driven by a variety of factors including [12] the need to:

- incorporate non-conventional generation such as wind power (as this has exposed the inadequacies of the existing peak security driven standards given the limited capacity value of wind generation);
- demonstrate that investment in monopoly functions is efficient and delivers the best value for consumers, i.e. provides the right balance between costs involved (paid by the users) and benefits that users derive from it, including reliability improvements;
- ensure that network planning and operational standards do not impose unnecessary barriers to entry and do not prevent a timely connection of new generating plants and demand;
- consider the application of advanced communication and information technologies as a part of electricity grid infrastructure, combined with recent developments of SPS, Wide-Area

Monitoring and Control Systems (WAMC), Dynamic Security Assessment techniques (DSA), Dynamic Line Rating (DLR), grid friendly controllers for Demand Side Management (DSM) etc. These techniques can provide an efficient solution for the provision of network security and lower the level of network redundancy [10-11,13-17]. For example, the new technology allows the use of corrective actions in the form of generation and demand response (both reductions and increases) to more efficiently manage network faults. In turn, the management of network injections and withdrawals following a network failure will allow network operators to accommodate increased power transfers through the existing grid, reducing the need for network redundancy.

1.1.3.2 Fundamental problems with the deterministic security standards

Deterministic rules for security are a binary measurement of risk, which is fundamentally problematic as highlighted in [18]: system operation in a particular condition is considered to be exposed to no risk at all if the occurrence of any selected single contingency does not violate the operational limits, while the system is considered to operate at an unacceptable level of risk if the occurrence of a credible contingency would cause some violations of operating limits. Evidently, neither of these is correct, as the system is indeed exposed to risks of failure even if no single circuit outage leads to violations of operating constraints, and the risk of some violations may be acceptable if these can be eliminated by an appropriate post-fault corrective action.

Furthermore, [18] points out that given that the outage probabilities, failure rate and repair time of transmission lines and other equipments are very different, it is not possible to deduce a single value to be used in a deterministic standard to quantify the risk the system is exposed to. In this context, it is important to recognise that deterministic standards assume that all contingencies are equally likely, which is fundamentally incorrect. For example, faults on a long, exposed line are much more frequent than failures of a closely monitored transformer.

Additionally, it is important to note that line outage probabilities change according to the prevailing operating conditions. For instance, during an adverse weather condition (thunderstorms, high winds, ice etc) the probability of failure is higher than under fair weather condition. Hence keeping the same levels of redundancy for all types of circuits under all conditions, as dictated by a deterministic standard, is inefficient. Such a deterministic standard might be good on average but it will not be appropriate for any individual event. Therefore, probabilistic standards must be used to adequately identify the risk for each individual event as shown in [19-22].

In general, deterministic criteria are applied by using preventive control which means that grid operation is secured by merely using redundancy, ignoring corrective actions. These actions range from adjusting control transformers, changing the network configuration, and modifying the economic schedule of units to a precalculated set of load-shedding alternatives as described in [23,24]. Although there are experiences of deterministic criteria with corrective control, the expected post-fault costs of those actions are ignored. This is problematic since the post-fault cost of operating SPS, for instance, over both demand and generation can be associated with significant costs (e.g. VoLL = £30,000/MWh and cost of tripping a generator £400,000)[1]. Ignoring these post-fault costs can lead to suboptimal operation and design.

In addition, the degree of security provided by deterministic criteria is unlikely to be optimal in any particular instance, as the cost of providing the prescribed level of security is not compared with the reliability benefit delivered[2]. In contrast, a standard that is established within a cost-benefit framework (probabilistic) is, in principle, superior over the deterministic approach, as it balances more accurately the reliability (and other) benefits against operation and investment costs incurred to deliver these benefits. Given the developments in reliability analysis techniques over the last 20 years, the evaluation of appropriate levels of security within a cost-benefit framework is now feasible.

Security standards in Chile, New Zealand, Victoria (Australia) and NERC have already incorporated some of these new technologies together with changing part of their security standards towards a more probabilistic framework [25-28].

Overall, the current concerns regarding present deterministic standards can be summarised as follows:

- they are inefficient and do not deliver value for money to network users, i.e. the system operators, following the present rules, unduly restrict users to access to the system and hence prevent optimal utilisation of the existing network infrastructure; and
- they require that network security is provided through asset redundancy, i.e. historical asset-heavy paradigm. This fundamentally contradicts the concepts of smart grid that focus on non-asset solutions to network problems. In other words, the current standards impose a barrier for innovation in network operation and design, preventing implementation of technically effective and economically efficient solutions that enhance the utilisation of the existing network assets and maximise network users' benefits.

[1] Actual costs in GB used in the assessments within the Fundamental Review of the Security and Quality of Supply Standards.

[2] The reliability benefit of an investment reflects the reduction in risk of service interruptions that accounts for the probability of an undesirable outcome and for the consequences of such an outcome.

1.2 Scope of the work and research questions

This thesis focuses on the problems originated by the current transmission network security standards in both operational and planning timescales. An alternative security framework is proposed and scrutinised. The new framework is based on probabilistic concepts and is more optimal in the delivery of transmission capacity to network users. It is therefore more efficient in terms of investment in new network assets and in the integration of renewable generation.

1.2.1 Research questions

This thesis questions the current network security framework and argues that transmission capacity delivered to network users (i.e. levels of utilisation) in operational timescales should include the contribution of non-network solutions composed of preventive and corrective operational measures. Apart from the typical switching actions and congestion management measures introduced by previous work, such as that detailed in [19], this thesis also considers the contribution of different allocations of generation reserves across the network to support higher network transfers. It is argued that the right balance between redundancy and contribution to security from non-network solutions has to be undertaken on a cost-benefit basis with full consideration to the probabilistic nature of the security problem; when and where the risk associated to outage events is low, redundancy levels should be minimised in order to permit higher power transfers. Consideration is given to the role of an array of system's parameters such as wind outputs (that can change the price of congesting the network and therefore of having forced unutilised network), weather conditions (that drive different outage probabilities and risk profiles) and prices or availability of generation reserve (that can support higher transfers through the network).

The questions addressed in this thesis are presented below. They are divided into several categories with the intention of helping the reader to understand the different dimensions of this research.

A. Security standards in operational timescales:

1. Does the current deterministic security standard deliver value for money to network users?

   There are debates in a number of jurisdictions regarding the balance between network costs and risks that are implicit in the network standards. This balance, although has delivered secure network operation in the past, will need to be recalibrated in the presence of new technology and renewables.

2. Should weather conditions impact the levels of network utilisation?

   Real reliability data suggest that network failures are significantly less frequent during fair weather conditions. These reduced outage rates could encourage network operators to lower their levels of network redundancy without having much increase in risk.

3. Can network operators deal with weather uncertainty in operational timescales?

   Since the system operation is planned ahead, there is a level of uncertainty associated to weather conditions. In this context, real advantages of potentially higher transfers that can be accepted under the assumption of 100% certainty in fair weather could not be realised under forecast uncertainty.

4. Can a better allocation of generation reserves facilitate higher network transfers?

   It is proposed that generation reserve, when competitive, could also be committed to deal with network problems and therefore reduce the levels of network redundancy.

   Furthermore, volumes of generation reserves will be at various times higher in order to deal with the uncertainty related to wind generation in the future. This increased volume of generation reserve could be shared and hence also used to cope with network outages. All these might facilitate the increase in transfers in the intact system.

B. Security standards with high penetration of new technology:

5. Can network redundancy be displaced by the deployment of alternative non-network solutions?

   Network redundancy can be minimised by using DR measures as shown in [29]. System-to-generation intertripping has similar effects on redundancy. There is also a need to investigate whether a more efficient system operation itself (e.g. different allocation of generation reserves) can actually decrease the level of network risks.

   All these suggest that there is a potential opportunity to minimise network costs and wind curtailments without the need to have large network redundancy levels.

6. How can the risk of malfunction of operational measures be addressed?

   The key concern regarding new technology (of network and communication) is with respect to its ability to react fast with reliability under outage events. As corrective actions can also fail, it is relevant to study whether the application of such technologies will decrease the levels of reliability of the network.

C. Security standards in planning timescales:

7. Can operational measures displace network assets?

   If networks can be used more intensively, then there is an opportunity to reduce future investment and still be able to integrate new wind generation.

8. If so, at which reliability cost?

   If network utilisation can increase, this will be accompanied with higher levels of operating costs or/and risks that have to be determined and understood.

9. With lower network investment, is the cost of congestion necessarily higher?

   Lower investment will necessarily drive higher congestion costs under deterministic security. However, because network utilisation can be also increased on the basis of non-network solutions or deployment of operational measures, it is not clear if this will actually increase the levels of congestion in a probabilistic framework.

D. Wind integration:

10. Can the present network assets be used to integrate more wind power?

    There is an opportunity to reduce the levels of network redundancy and allow higher power transfers and hence facilitate more cost effective integration of new renewable generation.

11. Can deterministic standards efficiently integrate wind in the long term?

    It is very likely that deterministic standards drive higher levels of network investment than probabilistic ones. However, as the current standards also imply lower levels of network utilisation, it is not clear that increased network investment will actually facilitate higher wind generation utilisation.

E. Economic benchmark with current security standards in the GB:

12. Are the current levels of transmission network redundancy in GB aligned with the levels of redundancy observed in a cost-benefit analysis?

    The current levels of network redundancy were derived in the 1950's and for an energy matrix composed mainly of conventional thermal generation. In light of the new context, these levels of redundancy should be carefully analysed and ultimately validated (or rejected and retuned).

13. What is the economic value of applying a probabilistic approach for security instead of the current deterministic one?

    If the current rules for network security are not efficient, then it is necessary to determine what the efficient levels of redundancy are and also their associated economic costs and risks.

F. Modelling of network security:

14. How can the potentially large computational burden of a probabilistic framework be handled in terms of mathematical modelling?

    Probabilistic analyses should consider, in theory, an uncountable number of different scenarios and their probabilities. Therefore, it is not clear how this very large set of potential network states can be limited without affecting the quality of the solution.

15. Can mathematical models be applied on a reasonable large transmission network?

    The size of the network also contributes to the aforementioned computational burden and thus it has to be proved whether the final proposal is, in real terms, applicable.

16. What types of simplifications are appropriate to balance accuracy and computational burden?

    All simplifications will have implications in terms of the accuracy of the optimum solution. Therefore, it is important to minimise these implications or, at least, to understand the impacts of the simplifications made.

17. Can critical network components for risk or critical outages be identified?

    In the context of both computational burden and component importance for risk, it can be meaningful to rank outages and network components in terms of their impacts on system reliability. This may serve to simplify calculations as well as to have a better understanding about what the critical outages and components are for system reliability.

1.3 Original contributions of the research

The original contributions of this thesis are described in chapters 3, 4 and 5. Chapter 3 sets out a complete probabilistic framework for network security to be used in operational timescales under high wind penetration. This shows, like other works [19, 29], how operating costs and risks can be balanced, but also how this approach can be used to facilitate integration of increased levels of wind generation while taking into account weather conditions, and the support of generation- and demand-based services to network problems. A framework is presented that can handle an array of system uncertainties to support network transfers like weather, wind generation and the malfunction of operational measures.

In Chapter 4 a probabilistic based model is presented that can optimise network redundancy in a complex transmission network. Due to the very large computational burden given by the number of operating condition and states that have to be analysed, especially in the planning problem, a novel algorithm is proposed which identifies the relevant outage scenarios that have to be loaded in the model and so eliminates the redundant information that does not contribute towards the optimum solution. This list of relevant outages can be also utilised to rank the importance of each network component according to its contribution to system reliability. It is proved that the reduced problem which considers only a selected subset of outages is (nearly) optimum and, in fact, converges to the same operational and planning solution as when all operating states are considered. In planning timescales, this scenario reduction is accompanied by the application of multi-threading techniques and by the proposal of a simple but accurate heuristic that improve the computational times. Based on this model, this chapter also demonstrates various fundamental advantages of the proposed probabilistic framework (and disadvantages of the deterministic framework) in a meshed network.

Finally, Chapter 5 contains three main original contributions. Firstly, that the current N-2 deterministic standards in GB actually drives a heterogeneous distribution of risk across the system (i.e. risk of demand curtailment in England is various times higher than the risk of demand curtailment in Scotland). Secondly, that the application of deterministic standards in planning timescales will drive higher levels of wind curtailment by 2020 even in the presence of increased network investment. Thirdly, that different weather patterns over parts of the UK (e.g. fair weather in Scotland and adverse weather in England or vice versa) have different impacts on the England-Scotland interconnector. An interesting numerical result shown in this chapter is that the application of probabilistic standards will lead to significant levels of saving in investment cost in GB, in particular, with respect to the proposed HVDC assets.

It is important to mention that while we have described security standards implications of the research carried out, it can be also viewed more broadly as providing optimisation tools to aid decision and analysis of transmission networks to take account of a wide range of phenomena, including random outages.

1.4 Thesis structure

This thesis is organised into three technical chapters (3, 4 and 5) plus Chapter 2 that describes the general concepts and international experience regarding security standards, and Chapter 6 that poses the main conclusions and further work. Chapters are ordered from general to particular albeit each chapter could be read in isolation[3]. The relevant literature review is included within each chapter.

Chapter 2 describes the main concepts in network security and the international experience in security standards.

Chapter 3 describes the overall framework which forms the basis of this thesis. The fundamental principles are described and scrutinised based on a 2-busbar system and GB data obtained during the Fundamental Review of the Security and Quality of Supply Standards (SQSS).

Chapter 4 shows the modelling concepts that are relevant to address the probabilistic evaluation of network security in a meshed system. In here, several techniques are applied to solve a large MILP such as Benders decomposition, heuristics and scenario reduction.

Chapter 5 shows a complete evaluation of the framework presented in Chapter 3 by using the model in Chapter 4 over the GB transmission network. Operational and planning studies are undertaken.

Chapter 6 poses the main conclusions and the further work to be done. In particular, the importance of incorporating the malfunction of corrective control in the meshed model is stressed as well as a new scenarios-selection module that can identify the relevant wind output conditions.

[3] Content repeated to make each chapter independent was carefully minimised.

CHAPTER 2: Review of main concepts and experiences in network security

Abstract

This chapter presents the main concepts of deterministic and probabilistic network security and reviews the international practices and experiences associated with security of network operation and design in 10 countries. Furthermore, the reasons and barriers to shift towards probabilistic security, considering the international context, are presented in this chapter. The incorporation of new advances in network control (and communication) technologies and new available computational tools within network operation and design practices are also reviewed. In light of the expected high penetration of renewables, the benefits of probabilistic standards are described in terms of delivering timely and efficient network capacity.

2.1 Introduction

To address the increased expected penetration of renewables, transmission network planning and operation will require fundamental changes together with considerable volumes of investment [5]. However, before the need for new network investment can be established, it is critical to ensure that rules that are used to determine the volumes of network capacity that should be released from current assets to network users in operational timescales are efficient. For instance, it is common to observe levels of underutilisation in transmission lines imposed by the network operator to preserve sufficient margins for system security[4] purposes. These security margins may, in turn, constrain network operation and make it more inefficient.

The basis for establishing an optimal level of network capacity that should be made available to network users (by network operators) in real time is a key issue. According to historical practice, this is achieved through various operational rules codified in the form of network standards that define minimum levels of network redundancy that must be maintained to cope with unexpected events, e.g. line outages. These security standards can be defined within either a deterministic (current situation) or a probabilistic framework. A description of the main concepts and experiences in security standards is presented next.

2.2 Main concepts in security standards

2.2.1 Main principles in deterministic security standards

Security standards have been traditionally based on deterministic operation and design criteria: electricity transmission networks should be able to withstand a loss of one or two circuits (i.e. N-1 or N-2 deterministic network criteria) without causing overloads of any other circuit and such outages must not threaten the integrity of system operation [10]. Under these events, demand cannot be shed[5]. In this framework, the outages against which the network is considered to be secured are called *credible events* and these are arbitrarily prescribed. The occurrence of further outage events (beyond

[4] Reliability is a broad concept used to indicate the overall ability of the system to perform its function. Power system reliability is divided into adequacy and security. Whilst adequacy is associated with the existence of sufficient facilities to satisfy demand or system operational constraints in static conditions, security relates to the ability of the system to respond to dynamic disturbances [30].

[5] Furthermore, in principle, no corrective action can be exercised if its utilisation cost is different to zero. Nevertheless, in practice contracts can exist that allow the network operator to curtail demand under the occurrence of outage events (note that the exercise fee of such a contract cannot be incorporated under the deterministic method).

the credible ones) is ignored. Example 2.1 illustrates the application of an N-2 deterministic rule over a simplified network in operational timescales.

Example 2.1: Deterministic security standards

The application of an N-2 deterministic criterion over a 4-identical-circuit transmission link will drive a maximum utilisation of 50% of the net physical capacity in the pre-fault condition. This level of network redundancy serves to have sufficient transmission capacity to withstand a double circuit outage (i.e. the capacity of the remaining network assets in the post-fault condition –right after the outage– must be sufficient to transport the same volume of power transfers as in the pre-fault condition). This situation is illustrated in Figure 2.1 where the post-fault line rating is assumed to be equal to the pre-fault one.

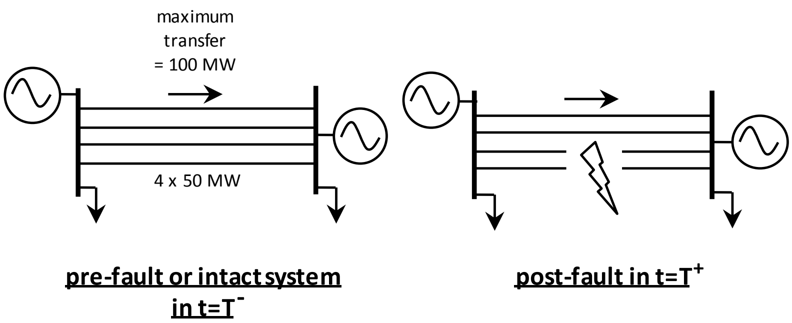

Figure 2.1: Deterministic N-2 principle illustrated under a fault occurring at t=T

In planning timescales, the philosophy above remains the same and the exercise is usually divided into 5 steps [31]:

1. Selection of the future demand scenario and the loading conditions to be analysed (peak, partial peak, minimum demand, etc);
2. Selection of the network configuration and generation outputs;
3. Selection of the set of credible outage events;
4. Simulation of the events over the conditions given by 1 and 2;
5. Identification of the solutions for any event resulting in the violation of the performance criteria.

Due to the presence of significant redundancy, deterministic practices have historically delivered a successful operation of large-scale and complex electric networks in the absence of advance technology to monitor, predict, simulate and control them in real time.

2.2.1.1 Mathematical formulation

The structure of the optimisation problem that represents the Security Constrained Optimum Power Flow (SC-OPF) that determines the levels of redundancy in operational timescales is [32]:

$$min\ C_0(\overrightarrow{x_0}, \overrightarrow{u_0}) \qquad \text{Eq. 2.1}$$

$$\overrightarrow{g_0}(\overrightarrow{x_0}, \overrightarrow{u_0}) = \vec{0} \qquad \text{Eq. 2.2}$$

$$\overrightarrow{h_0}(\overrightarrow{x_0}, \overrightarrow{u_0}) \leq \overrightarrow{L_l} \qquad \text{Eq. 2.3}$$

$$\overrightarrow{g_k^s}\left(\overrightarrow{x_k^s}, \overrightarrow{u_0}\right) = \vec{0} \qquad \text{k = 1..c} \qquad \text{Eq. 2.4}$$

$$\overrightarrow{h_k^s}\left(\overrightarrow{x_k^s}, \overrightarrow{u_0}\right) \leq \overrightarrow{L_s} \qquad \text{k = 1..c} \qquad \text{Eq. 2.5}$$

$$\overrightarrow{g_k}(\overrightarrow{x_k}, \overrightarrow{u_k}) = \vec{0} \qquad \text{k = 1..c} \qquad \text{Eq. 2.6}$$

$$\overrightarrow{h_k}(\overrightarrow{x_k}, \overrightarrow{u_k}) \leq \overrightarrow{L_m} \qquad \text{k = 1..c} \qquad \text{Eq. 2.7}$$

$$|\overrightarrow{u_k} - \overrightarrow{u_0}| \leq \Delta\overrightarrow{r_k} \qquad \text{k = 1..c} \qquad \text{Eq. 2.8}$$

Where C_0 is the cost in the intact system or pre-fault condition; $\overrightarrow{x_k}$ and $\overrightarrow{u_k}$ are the vectors of state (e.g. voltages at all nodes) and control (e.g. generators' output) variables, respectively, in the k-th outage (k = 0 is intact system); and $\overrightarrow{x_k^s}$ is the vector of state variables right after the outage and before the System Operator (SO) has had time to modify the control variables. $\overrightarrow{L_s}$, $\overrightarrow{L_m}$ and $\overrightarrow{L_l}$ are the short-, mid- and long-term line rating; and $\Delta\overrightarrow{r_k}$ denotes the maximal allowed adjustment (or rate) of the control variables. The number of contingencies analysed (i.e. c) correspond to only the credible ones. Importantly, $u_k = u_0$ when no corrective actions are allowed. Since Eq. 2.1 only considers pre-fault costs, the modification of control variables that have high cost associated (e.g. demand shedding) is in principle not permitted.

Eq. 2.2, 2.4 and 2.6 represents the AC or DC power flow equations and constraints Eq. 2.3, 2.5, 2.7 and 2.8 are aimed at preventing unrealistic results regarding the maximum line rating and control variables' rate limits. These equations are based on a steady-state analysis.

In here, the planning problem corresponds to the balance between the (annuitized) transmission investment cost and the total cost of operation over a year as shown in Eq. 2.9.

$$min\ C_{inv}\left(\overrightarrow{L_s}, \overrightarrow{L_m}, \overrightarrow{L_l}\right) + \sum_{i=1..n} C_0\left(\overrightarrow{x_{0,i}}, \overrightarrow{u_{0,i}}\right) \Delta T \qquad \text{Eq. 2.9}$$

Where $\overrightarrow{L_s}$, $\overrightarrow{L_m}$ and $\overrightarrow{L_l}$ are now control variables, n is the number of intervals used for the discretisation of time across the year and ΔT denotes the length of the time window. The subscript 'i' refers to the operating condition[6] (e.g. demand snapshot). C_{inv} is the cost of investment associated with network enhancements.

2.2.2 Main principles in probabilistic security standards

Instead of making a decision on the levels of network redundancy (for example, to secure the network against all single and double circuit outages) a probabilistic calculation of risk can be undertaken in order to derive the efficient levels of mitigating actions.

From the point of view of economic efficiency, improvements in the levels of reliability of a bulk power system should continue up to the point that the cost associated with such improvements exceeds the benefits of doing so [33,34]. Therefore, an optimal transfer in the operational timescale for a given operating condition (e.g. demand snapshot) will correspond to the point of minimum total costs that balances operating costs (O), such as the cost of transmission constraints and losses, and the expected unsupplied demand cost (X). This is carried out over an array of operating states[7] (i.e. outages) that are weighted according to their probabilities. As a result, levels of network utilisation (and redundancy) will be the efficient and balance the levels of risks associated with that particular operating condition. Figure 2.2 shows how different levels of power transfers through an existing transmission interconnector influence the key cost components. Also, the efficient transfer that optimally balances the cost of transmission constraints with the cost of expected unsupplied demand, among other costs, is shown.

[6] An “operating condition” is a particular snapshot of demand across the interconnected system.

[7] An “operating state” is a status of the system given by the availability state (available or outaged) of each element (generation and transmission) of the power system. Intact system is also an operating state.

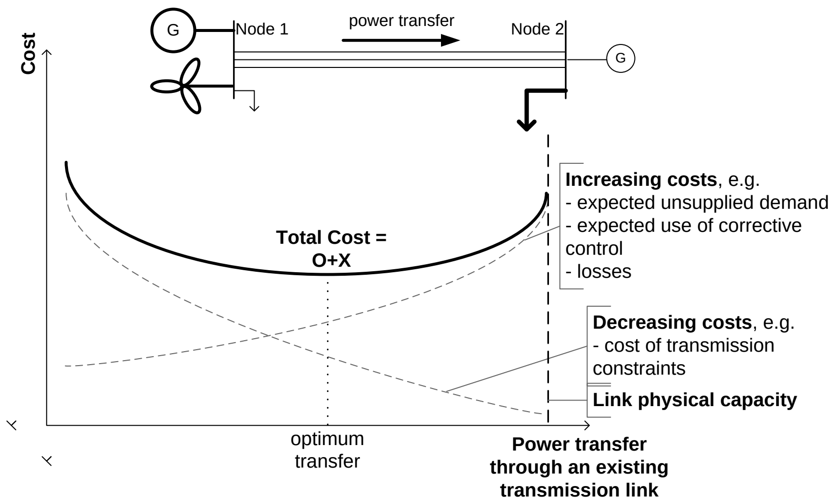

Figure 2.2: Balance to determine optimum transfer in a single transmission link – O+X optimisation

Design standards should also minimise, in the similar manner, the total optimum investment cost (T) against all operational costs (O) and risks (X). Figure 2.3 shows the efficient investment decision, when simultaneously optimising power transfers through an enhanced or new transmission link that optimally balances the cost of transmission constraints with the expected unsupplied demand cost, among other costs.

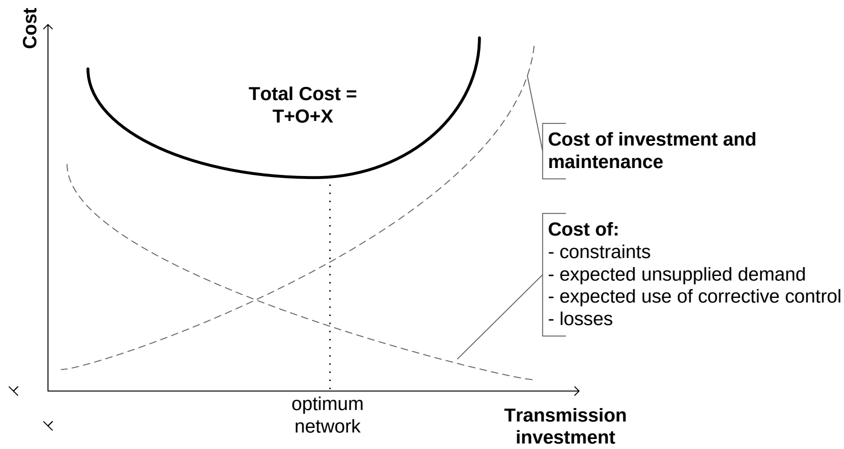

Figure 2.3: Balance to determine optimum investment decision – T+O+X optimisation

Given the probabilistic nature of the O+X and T+O+X optimisations (abbreviations that refer to the operational and planning problem, respectively, and introduced in [35]), these should include a range of outages (beyond typical N-1 and N-2 events).

It is important to mention that this equilibrium position is different across different system boundaries, will depend on the network characteristics and change with market (e.g. balancing prices) and system conditions (e.g. weather).

2.2.2.1 Mathematical formulation

Following the notation introduced by expressions Eq. 2.1 to 2.9, the formulation of the Probabilistic Optimum Power Flow (P-OPF) is given by:

$$min\ C_0(\overrightarrow{x_0},\overrightarrow{u_0}) + \sum_{k=1}^{M} p_k C_k(\overrightarrow{x_k},\overrightarrow{u_0},\overrightarrow{u_k}) \qquad \text{Eq. 2.10}$$

$$\overrightarrow{g_0}(\overrightarrow{x_0},\overrightarrow{u_0}) = \vec{0} \qquad \text{Eq. 2.11}$$

$$\overrightarrow{h_0}(\overrightarrow{x_0},\overrightarrow{u_0}) \leq \overrightarrow{L_l} \qquad \text{Eq. 2.12}$$

$$\overrightarrow{g_k^s}\left(\overrightarrow{x_k^s},\overrightarrow{u_0}\right) = \vec{0} \qquad k = 1..M \qquad \text{Eq. 2.13}$$

$$\overrightarrow{h_k^s}\left(\overrightarrow{x_k^s},\overrightarrow{u_0}\right) \leq \overrightarrow{L_s} \qquad k = 1..M \qquad \text{Eq. 2.14}$$

$$\overrightarrow{g_k}(\overrightarrow{x_k},\overrightarrow{u_k}) = \vec{0} \qquad k = 1..M \qquad \text{Eq. 2.15}$$

$$\overrightarrow{h_k}(\overrightarrow{x_k},\overrightarrow{u_k}) \leq \overrightarrow{L_m} \qquad k = 1..M \qquad \text{Eq. 2.16}$$

$$|\overrightarrow{u_k} - \overrightarrow{u_0}| \leq \Delta\overrightarrow{r_k} \qquad k = 1..M \qquad \text{Eq. 2.17}$$

Where C_k is the cost in the operating state k and p_k is the probability of that outage. M represents the number of total possible outages. A fundamental difference between the deterministic and the probabilistic formulation is that, in the latter, demand is also a control variable.

In here, the planning problem corresponds to the balance between the (annuitized) transmission investment cost and the total cost of pre- and (expected) post-fault operation over a year as shown in Eq. 2.18.

$$min\ C_{inv}\left(\overrightarrow{L_s},\overrightarrow{L_m}\ ,\overrightarrow{L_l}\right)\ + \sum_{i=1..n}\left[C_0\left(\overrightarrow{x_{0,\iota}},\overrightarrow{u_{0,\iota}}\right) + \sum_{k=1}^{M} p_{k,i} C_k\left(\overrightarrow{x_{k,\iota}},\overrightarrow{u_{0,\iota}},\overrightarrow{u_{k,\iota}}\right)\right]\Delta T \qquad \text{Eq. 2.18}$$

As in Eq. 2.9, n is the number of intervals used for the discretisation of time across the year and ΔT denotes the length of the time window. The subscript ‘i’ refers to the operating condition. C_{inv} is the cost of investment associated with network enhancements.

2.3 International experience

In almost all countries, the Main Interconnected Transmission System (MITS) is operated and designed based on deterministic decision-making methods in order to deliver network capacity to users. Several jurisdictions have already carried out reviews and changes in their regulatory framework to include probabilistic and cost-benefit-analysis (CBA) considerations for security. These considerations, however, have been mainly applied on particular cases [31, 36-38] or in combination with deterministic concepts (see Table 2.1).

For example, a recent survey over ten countries[8] shows that only one of them, Chile, applies (nearly) full probabilistic concepts on its MITS. In addition, two countries, New Zealand and Brazil, use combinations of deterministic and probabilistic whilst all the rest only apply deterministic concepts.

Table 2.1: International experience in operational and planning security over the MITS

Country (body surveyed)	Operational security	Planning security
Chile (Transelec)	N-1 with probabilistic relaxation	N-1 with probabilistic relaxation
New Zealand (Transpower)	N-1 in the core network N-k in the economic network, with k derived by a CBA	N-1 in the core network N-k in the economic network, with k derived by a CBA
GB (National Grid)	N-2	N-2
USA (National Grid)	N-1	N-1-1 (considering one planned outage)
France (RTE)	N-1 and N-2 for double circuit	N-1 and N-2 for double circuit
Spain (REE)	N-2	N-2
Ireland (Eirgrid)	N-1	N-1
Belgium (Elia)	N-2	N-2
Japan (Tohoku)	N-1 and some N-2	N-1 and some N-2
Brazil (PSR)	N-1 with probabilistic relaxation	N-1

Levels of redundancy driven by N-2-type standards are, however, being questioned. For instance, in Sweden security standards were recently changed from N-2 to a mix of N-1 and N-2 [40]. Furthermore, there is an interest in the European Union to explore the benefits of applying probabilistic security standards, especially in the context of facilitating a cost effective integration of new renewable resources (e.g. iTesla in [41]). The interest in this topic has increased because of the concerns with costs associated with transmission expansion plans potentially required to integrate both off and onshore infrastructure for wind generation and the potentially growing complexity of system operation.

In countries with probabilistic standards like Chile, each outage is assessed in a cost-benefit fashion when considering its (average[9]) probability of occurrence together with its impacts on demand curtailment at a certain price or Value of Lost Load (VoLL). As a result, network investments justified by reliability reasons are only carried out if their associated improvements in the expected

[8] Original data obtained from [5, 39]. The author of this thesis participated in both studies.

[9] Changes in the probability of occurrence of an outage due to different operating conditions (e.g. weather) are not considered in Chile.

cost of unsupplied demand are higher than their investment costs. This assessment leads to a situation where certain areas of the transmission system are, in effect, N-1 secured whilst other areas have higher or lower levels of security. This case is depicted in Figure 2.4.

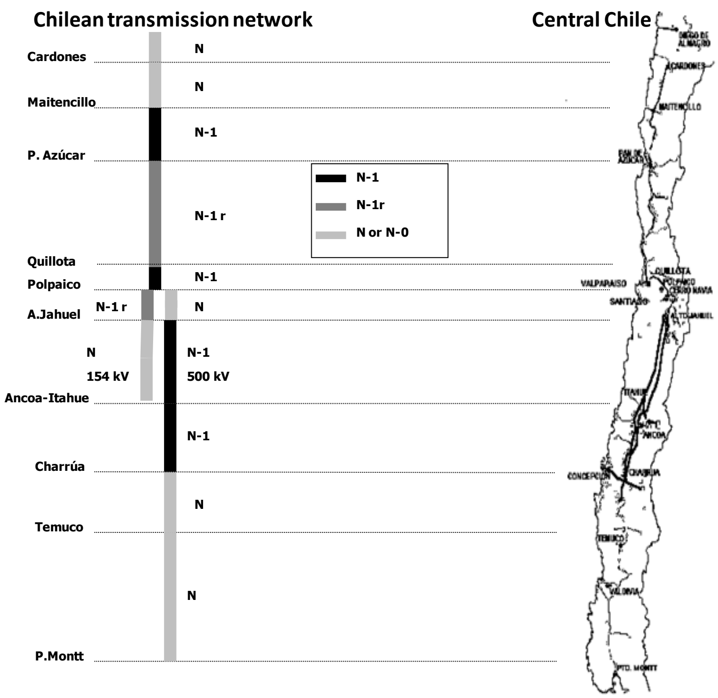

Figure 2.4: Security criteria of the main interconnected transmission system of Chile [27]

In Figure 2.4, "N" indicates areas where a single network fault drives controlled volumes of demand shedding (i.e. N-0 areas) through SPS, "N-1" indicates areas that can withstand a single transmission outage with no corrective actions and "N-1r" indicates areas that can withstand single transmission outages by accepting network overloads during the first 15 minutes and then using generation re-dispatch as a corrective measure. In N-0 areas, the cost of the necessary network investment to comply with an N-1 criterion is more expensive that the saving levels in the cost of reliability or expected unsupplied demand.

In the Chilean example, it is important to highlight the participation of SPS that allows the SO to control the amount of demand or generation being shed when certain network outages occur. If neither corrective actions nor redundant network capacity were in place, the occurrence of an outage would lead to the cascading failures of network components that could potentially lead to an entire system collapse [10]. The relationship between new network technology such as SPS and probabilistic methods for network security is illustrated in Example 2.2.

Example 2.2: Support from new technology

Recent experiences show that SPSs can be used to effectively solve numerous post-fault problems ranging from steady state to constraint violations to potential loss of stability. They can enhance the transfer capabilities of the existing network, and hence postpone or even eliminate the need for network reinforcement. A body of industry practices and experiences recently presented at CIGRE show that SPSs can be used to postpone or eliminate reinforcement related investment in grid infrastructure. Since the seminal article of SPS performance, presented in 1994 by a joint IEEE-CIGRE working group [14], there have been a number of papers presented by practitioners (particularly at the last three CIGRE conferences) reporting very successful and reliable operation of SPS. These schemes were all employed to increase the existing transmission network capability and avoid costly reinforcement in countries such as Canada, Brazil, and Sweden [36-38, 42-47].

The Norway-Sweden interconnector presents an interesting case where even high risk operations like N-0-type transfers are allowed provided that the selected undesirable events can be managed through a set of post-fault actions. In this case, the corrective actions comprise shedding or fast reduction of hydro generation, fast regulation of HVDC links, selective disconnection of big industrial loads and network splitting. The capacity increase achieved was from 2 GW up to 3.6 GW [37].

Corrective actions are not only limited to curtailment of generation and demand. In fact, generation re-dispatch (including the dispatch of fast generating units), topology configuration, use of Flexible AC Transmission Systems (FACTS) and phase shifters can serve as a remedial action after a transmission network outage occurs in order to minimise the possibility and time duration of network overload [48]. For instance, generation re-dispatch is a useful measure used in Chile after a network fault occurs so as to eliminate the temporary overload produced in areas with N-1r security criteria. Post-fault topology configurations are used in PJM as a corrective measure [49].

The Fundamental Review of the Security and Quality of Supply Standards (SQSS) in the UK together with the derogation of these standards over a main GB MITS corridor (i.e. the England-Scotland interconnector) gives evidence about the need to move towards a more probabilistic approach. In fact, the OFGEM's consultation CAP 170 [50] establishes that SPS, due to the low probability of tripping, should represent a more economic and efficient means for managing constraints than the alternative bid-offer action to constrain generation pre-fault. Although the application of this new initiative has been so far deterministic (given that the penetration of SPS is still very limited and the constraints cost is high), it can be demonstrated that a probabilistic assessment should be used if the current standards are derogated on more boundaries. This is because probabilistic standards can determine the appropriate level of penetration of these measures. In other words, costly post-fault generation shedding (£400,000 per unit tripped) makes the exploitation of further SPSs in a deterministic basis unsustainable since utilisation costs are not considered under this framework.

To sum up, there is an increasing interest in the application of probabilistic methods for network security in a number of countries and a natural departure from deterministic practices towards more probabilistic ones since the penetration of new network technology has already started. These probabilistic methods will permit the replacement of network redundancy for a number of corrective actions that will allow SOs to deliver more network capacity to users through the already installed network assets.

2.4 Towards probabilistic network operation and design standards

Although transmission networks, designed and operated in accordance with the historic deterministic standards, have broadly delivered secure and reliable supplies to customers, the key issue regarding the future evolution of the standard is associated with the question of efficiency of the use of existing assets and the role that advanced, non-network asset based technologies could play in the future development.

Recently, there has been a recognition from both industry and academia, at an international level, about the potential benefits of moving towards probabilistic standards [31, 32]. A comprehensive report recently published by CIGRE in collaboration with utilities from Canada, Denmark, Sweden, USA, Ireland, New Zealand, Italy, Australia, Spain, Japan, Belgium, Germany, France, South Africa, UK, Switzerland, Norway and Greece, establishes the need for risk-based and probabilistic tools for power system planning and operation [31].

Overall, there are two key types of concerns:

- Is the present network operation and design standard efficient? Does it deliver value for money to network users? In other words, does it balance the cost of network infrastructure with the security benefit delivered to network users?
- Given that the present network design standards require that the network security is provided through asset redundancy, will this impose a barrier for the innovation in the network operation and design and prevent implementation of technically effective and economically efficient solutions that enhance the utilisation of the existing network assets and maximise network users' benefits?

Under these two key areas, there are a number of specific issues that should be considered:

- The binary approach to risk as in the present deterministic standard is fundamentally problematic: system operation in a particular condition is considered to be exposed to no risk at all if the occurrence of faults, from a preselected set of contingences, do not violate the operational limits; while the system is considered to operate at an unacceptable level of risk if the occurrence of a credible contingency would cause some violations of operating limits. Clearly, neither of these is correct, as the system is indeed exposed to risks of failure and outages even if no single circuit outage leads to violations of operating constraints, and the risk of some violations may be acceptable if these can be eliminated by an appropriate (post fault) corrective action.
- In several cases, asset redundancy may not be good proxy for actual security delivered. In this context, it is important to recognize that deterministic standards assume that all contingencies are equally likely, which is clearly problematic: for example, faults on a long exposed line are much more frequent than failures of a closely monitored transformer.
- The present standards do not deal well with common mode failures and do not provide any guidance for dealing with high impact low probability events.
- There is a growing interest in incorporating non-network solutions, such as flexible generation and flexible demand, in the operation and design of future networks. It is not, however, clear to what extent the application of such solutions changes the security of supply delivered to the end consumers. This is critical for quantifying the ability of non-network solutions to substitute for network assets.
- At present, the choices that network users (both demand and generation) can exercise in relation to their security of supply are limited. This may be a barrier for connections, particularly for generation. If choice is to be offered to users, understanding of the network reliability profile will be essential (in addition to the development of reliability differentiating charging/reward mechanisms).

The concerns about the inefficiencies associated with the deterministic operation and investment are discussed in [19,21,22,51].

Although the majority of the issues concerning deterministic standards are well-understood [52], probabilistic standards have presented historical opposition because of the reduced knowledge of practitioners about risk-based assessment and the scarce existing computational support [31]. In addition, the current regulatory framework impedes the proliferation of solutions based on innovative non-network solutions rather than asset-heavy network investment [5].

2.4.1 Barriers to the application of probabilistic standards

As mentioned earlier, although probabilistic methods are being considered, the actual application is still limited. This is because there is a number of concerns regarding probabilistic criteria that constrain their applications such as: the lack of accurate reliability data; the need for effective reliability and economic assessment/simulation tools that can study several operating/planning alternatives over an array of network operating conditions and planning scenarios; and uncertain reliability performance of communication and corrective control components.

Population of reliability data

In general, transmission companies and SOs have little experience in collecting standardised network performance data such as outage rates and repair times. For instance, the recent effort of the 3 licensees in the UK[10] to gather historical reliability data over the entire GB was, in fact, the first time that GB-wise data were collected and jointly analysed by the transmission licensees [53]. Moreover, in some areas of Scotland only data from 2005 could be collected.

Probabilistic tools

Reliability analysis is not only limited by the lack of enough representative and accurate data but also by the limited number, capability and flexibility of probabilistic commercial tools developed worldwide. Although these tools are very accurate in power flow calculation and outage state analysis, these are mainly utilised to measure risk indices such as the Lost of Load Probability (LOLP) and the Expected Energy not Supply (EENS) [31]. Tools for transmission operation and planning analysis can be observed in Table 2.2.

Table 2.2: Commercial tools for probabilistic transmission analysis

ID	Tool	Programmer
1	TRELSS & TransCARE	EPRI
2	TRANSREL	GR USA
3	OSCAR	Kinectrics
4	PROCOSE	Hydro One Canada
5	TPLAN	Siemens PTI
6	CREAM	EPRI
7	MECORE	U of Saskatchewan and BC Hydro Canada
8	NH2	CEPEL Brazil
9	CORAL	PSR, Inc
10	PowerFactory Reliability Analysis Tool	DIGSILENT
11	ASSESS	RTE, France and NGT, UK

The full probabilistic planning exercise involves more than the calculation of reliability indices, however. In principle, costs and risks have to be measured over a large number of outages and operating conditions that in theory form an uncountable set of network scenarios. The very large

[10] National Grid, Scottish Power and Scottish and Southern Energy.

number of interrelated scenarios to be analysed remains a challenge. In addition, more difficulties arise when considering the presence of discrete variables, for example to represent the action of SPS, and the non-linearity elements of the optimisation in complete AC power flow models [32].

Reliability of smart grid technology

Applications of more complex network control, automation and advanced protection schemes, such as potentially more sophisticated intertripping schemes are supported by high-speed telecommunication networks. These might pose additional operating risk if they fail to operate correctly due to inappropriate settings, faults, corrupted data, communication delay, etc and this risk needs to be understood, quantified, and managed to ensure that the integrity and security of the overall system is not compromised. Efficiently managing risks associated with the increased application of operational measures is critical for the future development and implementation of alternative network control and design philosophies. In this context, it is possible to observe an increased interest from network operators to investigate the implications of communication delay or failures when applying corrective control [54].

2.5 Key benefits of probabilistic standards

A probabilistic approach provides a consistent cost-benefit based framework for the development of future network operation (and development) standards. It provides the basis for the evaluation of the network capacity that could be released to network users in real time. It enables the costs involved in system operation to be balanced against the benefits that the released network capacity delivers to network users. Through a probabilistic approach, economic efficiency in maintaining security of supply can be achieved.

Probabilistic standards enable reliability to be graded below and above the level provided by the conventional deterministic N-1/N-2 criteria, depending on costs and benefits involved. Probabilistic standards provide a framework within which both network and non-network solutions for solving network problems can be objectively compared. As shown earlier, probabilistic network standards are conceptually superior to deterministic planning standards, are in line with recent developments overseas (VENCorp, Chile, New Zealand), and are consistent with the initiatives driven by the development of smart grid concepts.

Additionally, probabilistic frameworks can provide reassurances to all parties, i.e. the system operator, the network users and the regulators that appropriate balance is being struck between costs and benefits in the decision making process associated with the release of network capacity in the short and long term. This is important for demonstrating that the network delivers maximum benefits to its users.

Furthermore, there has been a trend in making use of advances in various technologies that can be utilised to provide the security through a more flexible and complex system operation, rather than through asset redundancy only. This includes advanced technologies such as dynamic line rating, coordinated special protection schemes, coordinated corrective power flow and voltage control techniques (potentially supported by wide area monitoring, protection and control technologies), use of wind generation with power electronic interfaces to enhance the stability performance of the network, application of advanced maintenance techniques, advanced decision making tools etc, combined with the application of demand and generation based solutions to network problems. It is however important to stress that probabilistic standards provide an opportunity for a range of non-traditional reliability enhancements to be consider and conceptually this should, in the long term, lead to an improved network reliability profile.

There is a consensus that there is now an important opportunity to shift the network operation and design philosophy from being restricted to solutions based on network assets only to become open to all solutions.

<u>CHAPTER 3:</u> Integrated reliability and cost-benefit-based standards for transmission network operation: the fundamental framework

Abstract

This chapter presents a probabilistic cost-benefit framework for the development of future efficient operating strategies and network security standards enabled by new technology. By optimally balancing the costs of network constraints with various operational measures composed of preventive and corrective control actions (considering potential outages of network and generation facilities) optimal network capacity that could be released to network users in real time is determined. This framework is compatible with smart grid concepts integrating new generation, network, and demand technology.

The studies demonstrate that any attempt to fix a single generic rule for operating the network, as in the present deterministic standards, will lead to potentially significant inefficiencies. It is also shown that various operational measures (such as generation and demand response) can be effectively used to release additional network capacity. The results show that the probabilistic approach provides the basis for the development of future network operation and design standards that would maximise the value of transmission network to users, enhance the utilisation of existing networks, foster the entrance of new technologies that may complement and provide alternative network reinforcement and hence facilitate more efficient integration of renewable generation.

3.1 Chapter's nomenclature

3.1.1 Parameters

Parameters' names are all set in normal font.

d_n	Total power demand at node n	MW
$\overline{\mathrm{f}}^{c,pf}$	Seasonal, post-fault and normal circuit ratings at operating state c during post-fault period pf	MW
M	Number of operating states	
Ng	Number of generators	
$\underline{\mathrm{p}}_g, \overline{\mathrm{p}}_g$	Minimum stable generation and maximum output of generator g	MW
$\mathrm{p}_\mathrm{g}^\mathrm{ED}$	Unconstrained dispatch output for generator g	MW
$\mathrm{pout}_n^{c,pf}$	Power outage on node n at operating state c during post-fault period pf due to generation failure and/or wind variations	MW
Pr_i	Probability that individual network component i will be outaged	p.u.
$\mathrm{P}_{state\ c}^{transmission}$	Probability of occurrence of the transmission configuration associated with operating state c	p.u.
$\mathrm{P}_{state\ c}^{generation}$	Probability of occurrence of the generation configuration associated with operating state c	p.u.
$\mathrm{pe}_\mathrm{x}^\mathrm{c}$	Probability of occurrence of the component status (x=g –generator–, x=l or –circuit–) associated with operating state c	p.u.
$\mathrm{p}_{\mathrm{l,y}}$	Probability of outage of line l. If l is a single circuit (y=1) or a double circuit (y=2)	p.u.
voll_n	Value of lost load at node n	£/MWh
$\Delta\mathrm{rspup}_g$	Net response that generator g can provide when ramping up	MW
$\Delta\mathrm{resup}_g$	Net reserve that generator g can provide when ramping up	MW
$\Delta\mathrm{resdwn}_g$	Net ramping down limit for generator g during reserve period	MW
λ_i	Failure rate of individual network component i	occ/h
λ_x	Failure rate of component x (generation unit x=g, single circuit x=l,1 and double circuit x=l,2)	occ/h

$\pi\mathrm{bid}_g$	Bid price submitted by generator g	£/MWh
$\pi\mathrm{itrp}_n$	Utilisation price of SPS (also called inter-tripping schemes) provided at node n	£/MW
$\pi\mathrm{off}_g$	Offer price submitted by generator g	£/MWh
$\pi\mathrm{res}_g$	Price of holding reserve services provided by generator g	£/MWh
$\pi\mathrm{rsp}_g$	Price of holding response services provided by generator g	£/MWh
ρ^c	Probability of occurrence of operating state c	p.u.
τ^{pf}	Duration of the post-fault period pf. pf=1 response period, pf=2 reserve period	h

3.1.2 Variables

Variables' names are all set in *italic* font.

bid_g^c	Accepted bid from generator g at operating state c	MW
$f^{c,pf}$	Power flow at operating state c during post-fault condition pf	MW
$itrp_n^c$	SPS (also called inter-tripping) utilised in node n at operating state c	MW
$ll_n^{c,pf}$	Loss of load at node n at operating state c during post-fault period pf	MW
$nres_g$	Accepted reserve service from generator g	MW
$nrsp_g$	Accepted response service from generator g	MW
off_g^c	Accepted offer from generator g at operating state c	MW
$p_g^{c,pf}$	Output of generator g at operating state c during post-fault period pf	MW
res_g^c	Utilised reserve service from generator g at operating state c	MW
rsp_g^c	Utilised response service from generator g at operating state c	MW
γ_g	Scheduling status of generator g. 1 if on, 0 otherwise	binary

3.2 Introduction

In light of the significantly increased levels of transmission network investment needed to integrate renewables, it is critical to ensure that rules used to determine the volume of network capacity that can be released from current assets to network users in operational timescales are efficient. Therefore, it is necessary to determine the optimum level of power transfer that balances risks and benefits. As highlighted in the previous chapters, this can be considered within an appropriate probabilistic framework.

In this context, the aim of this chapter is twofold. First, it presents a framework for the development of probabilistic network operation and design criteria that incorporates various operational measures based on alternative smart grid concepts which allows generation, transmission, and demand corrective actions to be coordinated in both pre- and post-fault time windows. This is important for systems with high penetration of wind generation located in remote areas that would, under deterministic rules, require additional network reinforcements that can be partially substituted by a number of more cost-effective operational measures.

Second, the framework developed in this chapter is illustrated on a simplified case of future operation of the England-Scotland interconnector and this is used to assess its potential benefits together with addressing the current concerns regarding the present deterministic Security and Quality of Supply Standards (SQSS).

3.3 Optimum power transfer: a probabilistic framework adapted for new technology

3.3.1 Fundamentals

From a probabilistic cost-benefit viewpoint, system security should be improved up to the point that the cost associated with such improvements exceeds the benefits of doing so [33]. As explained in Chapter 2, the marginal benefits for customers due to an extra unit of security can be measured by the customer outage cost or expected unsupplied demand cost as defined in [34]. Consequently, in this proposal, the efficient level of security of a given operating condition[11] is disclosed by an optimal balance between operating costs (O), i.e. cost of transmission constraints, various forms of generation reserves, losses, cost associated with availability and potential exercise of various operational

[11] An “operating condition” is a particular snapshot of demand across the interconnected system. Usually, it is assumed fixed in 30-min intervals.

measures (Special Protection Schemes –SPS–, Demand Response –DR–, etc.), among others, and the expected unsupplied demand cost (X). Figure 3.1 in which significant amounts of less expensive (more efficient) generation are located in node 1 and the majority of demand in node 2, shows how different levels of power transfer through an existing transmission link (composed of potentially several circuits) influence the key cost components.

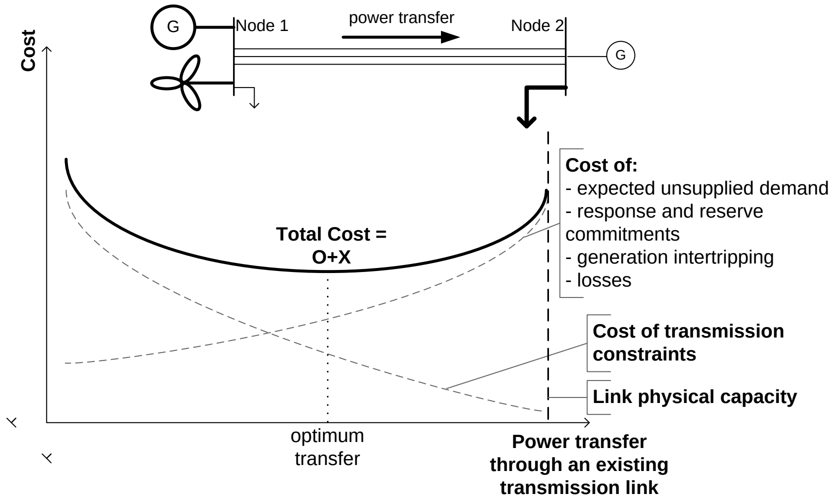

Figure 3.1: Balance to determine optimum transfer in a single transmission link

This equilibrium position may be different across each system boundary and is dependent on the network characteristics and changes in the weather and system conditions. For example, during fair weather conditions the probability of network failures would be lower than that observed under adverse weather (thunderstorms, high winds, ice etc) [55]. Hence, under fair weather conditions, given the lower probability of transmission line outages, system operators could make available to users larger amounts of network capacity than under adverse weather as shown in Figure 3.2a.

Similarly, the optimal power transfer may vary with system loading conditions and/or wind availability. Given that constraints costs, due to restricted power transfers, will be the highest when wind power is constrained, it may be more cost-effective to accept higher power transfers in such conditions as illustrated in Figure 3.2b.

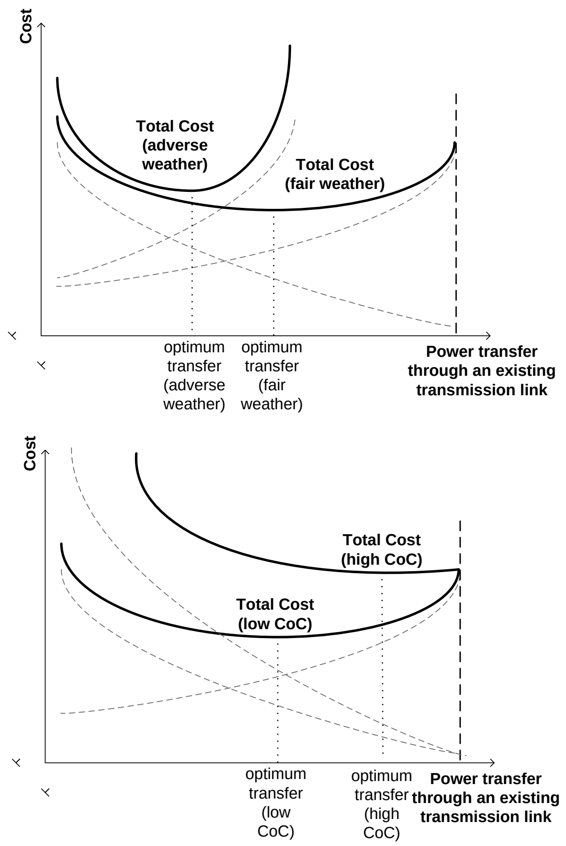

Figure 3.2: Balance to determine the optimum transfer in a single transmission link under different weather conditions (a. upper) and cost of constraints (CoC) levels (b. lower)

There may be some correlation between weather conditions, wind generation outputs and the overall physical transmission capacity, assuming that Dynamic Line Rating (DLR) techniques are applied. These changes in the overall physical capacity would have to be included in the proposed cost/risk balance in order to obtain more efficient levels of power transfers.

The optimum transfer can be affected by a number of other parameters such as constraints prices, Value of Lost Load (VoLL), response and reserve holding levels and their associated costs, cost of availability and exercise of various operational actions, etc. To assess the impact of these on the GB system, a probabilistic model named O+X has been developed. This analyses power transfers through a single boundary when considering: (i) a comprehensive list of contingencies or operating states[12] (beyond N-1 and N-2 types) in a probabilistic fashion in order to achieve global optimality; and (ii) coordination of dispatch and re-dispatch actions between generation, transmission, and demand response during pre- and post-fault periods to take account of smart grid technology.

[12] An "operating state" is a status of the system given by the availability state (available or outaged) of each element (generation and transmission) of the power system. Intact system is also an operating state.

3.3.2 The model for assessment

Given the initial market or contract position of every network user in a particular operating condition (i.e. energy committed between generators and consumers through contracts), it may be necessary to vary generators' outputs with respect to their initial positions by constraining generators off and on (i.e. accepting bids and offers, respectively) in order to satisfy network constraints and to manage system risks. Apart from modifying generator's output, and therefore modifying power transfers in transmission, it is also possible to commit different levels of generation reserves, which take account of the amounts of spare capacity needed, at a generation level, to deal with unexpected events, e.g. outages of generation units and transmission circuits. For instance, in order to cope with the outage of the biggest unit running in the system without disconnecting demand, there must be sufficient generation capacity available to restore demand-supply balance, i.e. system frequency. Depending on how fast this spare generation capacity can react, different services are defined.

In this model, services related to the automatic very fast response from generation (in the order of seconds), i.e. primary frequency response; and services related to the slower (in the order of minutes) centrally controlled generation reaction, i.e. synchronised reserve, are considered. Also, the model considers the application of SPS that can modify generation and demand volumes right after an outage of a line occurs. These are used to enhance the utilisation of the network assets by enabling higher pre-fault power transfers between exporting and importing areas of the system. Following an outage of a circuit that disconnects exporting and importing areas of the system, SPS automatically disconnects (or instigate rapid reduction of) generation in exporting areas to avoid network overloads. Disconnection of generation in exporting areas would lead to imbalance of generation and demand in the system, which would then be restored by increasing generation or by reducing demand in the importing area. In this framework, holding generation reserves (or demand side management) can deal with outages not only of generating plants but also of transmission circuits. Given that all of these actions are associated with costs, it will be important to balance them with the consequences of outages.

Therefore, the objective function of the proposed O+X model is to minimise Eq. 3.1 as follows:

$$Min\left\{\begin{array}{l}\sum\limits_{g=1..Ng}\left\{(\tau^{pf=1}+\tau^{pf=2})\cdot(\pi\mathrm{off}_g\cdot off_g^{c=1}-\pi\mathrm{bid}_g\cdot bid_g^{c=1})\right\}+\\ \sum\limits_{\substack{c=2..M\\ g=1..Ng}}\left\{\rho^c\cdot\tau^{pf=2}\cdot(\pi\mathrm{off}_g\cdot off_g^{c}-\pi\mathrm{bid}_g\cdot bid_g^{c})\right\}+\\ \sum\limits_{g=1..Ng}\left\{(\tau^{pf=1}+\tau^{pf=2})\cdot(\pi\mathrm{rsp}_\mathrm{g}\cdot nrsp_g+\pi\mathrm{res}_\mathrm{g}\cdot nres_g)\right\}+\\ \sum\limits_{\substack{c=2..M\\ n=A,B}}\left\{\rho^c\cdot\pi\mathrm{itrp}_\mathrm{n}\cdot itrp_n^c\right\}+\sum\limits_{\substack{c=2..M\\ pf=1..2\\ n=A,B}}\left\{\rho^c\cdot\tau^{pf}\cdot\mathrm{voll}_n\cdot ll_n^{c,pf}\right\}\end{array}\right\} \qquad \text{Eq. 3.1}$$

The five summations in the objective function respectively represent: (i) cost of transmission constraints in the intact system[13] which arises from offers and bids accepted ($off_g^{c=1}; bid_g^{c=1}$) which are charged regardless of outages occurring and for the entire time window ($\tau^{pf=1}+\tau^{pf=2}$); (ii) cost of expected transmission constraints under contingencies or reserve utilisation cost or re-dispatch cost which considers all operating states' probabilities (ρ^c) and is charged only when re-dispatching actions are taking place (i.e. during $\tau^{pf=2}$); (iii) cost of generation response and reserve availability which is charged regardless of outages occurring, for the entire time window and is paid to all generators that held these services; (iv) cost of expected SPS utilisation to shed generation which considers all operating states' probabilities and is charged regardless of the time window's duration because this service corresponds to a fee applied per tripping event; and (v) cost of expected unsupplied demand (which is also shed by using SPS) that depends on operating states' probabilities and the duration of the interruptions. All these summations are based on the multiplication of a power volume (in MW), a price (in £/MWh or £/MW/h or £/MW per event), and, in some cases, a time period (in h) and a probability (in p.u.).

In the model, the first operating state (c=1) is the intact system and this is coupled with all considered contingent states because the post fault generation re-dispatches must consider the intact system operation as an initial condition. The outage probabilities of individual network components are obtained from their failure rates assuming an exponential distribution according to [56] as shown in Eq. 3.2. More details about outage rates can be found in Appendix A.

$$\mathrm{Pr}_i = 1 - e^{-\lambda_i \times \mathrm{T}} \qquad \text{Eq. 3.2}$$

By simplifying Eq. 3.2 according to its first order Taylor approximation (i.e. $1-e^{-\lambda\cdot t} \xrightarrow{t\to 0} \lambda\cdot t$), we compute the probability of outage of generation and transmission as shown in Eq. 3.3 where common mode failures for double circuits are also considered.

$$\begin{aligned}
&\rho^c = \mathrm{P}_{state\ c}^{transmission} \times \mathrm{P}_{state\ c}^{generation} \\
&\mathrm{P}_{state\ c}^{generation} = \prod_{g \text{ dispatched}} \mathrm{pe}_g^c \ ; \text{ where } \mathrm{pe}_g^c = \begin{Bmatrix} \lambda_g \cdot \mathrm{T} & \text{if failed in c} \\ 1-\lambda_g \cdot \mathrm{T} & \text{if working in c} \end{Bmatrix} \\
&\mathrm{P}_{state\ c}^{transmission} = \prod_{l=1..Nl} \mathrm{pe}_l^c \ ; \text{ where } \mathrm{pe}_l^c = \begin{Bmatrix} 1-2\times \mathrm{p}_{l,1} + \mathrm{p}_{l,2} & \text{if N-0 in c} \\ 2\times(\mathrm{p}_{l,2}-\mathrm{p}_{l,1}) & \text{if N-1 in c} \\ \mathrm{p}_{l,2} & \text{if N-2 in c} \end{Bmatrix} \text{ if } l \text{ is double} \\
&\qquad\qquad \text{or } \mathrm{pe}_l^c = \begin{Bmatrix} 1-\mathrm{p}_{l,1} & \text{if N-0 in c} \\ \mathrm{p}_{l,1} & \text{if N-1 in c} \end{Bmatrix} \qquad \text{if } l \text{ is single} \\
&\text{with } \mathrm{p}_{l,1} = \lambda_{l,1}\cdot \mathrm{T} \text{ and } \mathrm{p}_{l,2} = \lambda_{l,2}\cdot \mathrm{T}
\end{aligned} \qquad \text{Eq. 3.3}$$

[13] Before a fault occurs

Common mode probability is derived when considering that single outages in a double-circuit line are not mutually exclusive. Therefore, for example, the probability of having an N-0 state in a double circuit configuration is equal to P{circuit A works and circuit B works} = P{A works} + P{B works} – P{A works or B works} = P{A works} + P{B works} – (1 – P{A fails and B fails}) = (1 – $p_{l,1c}$) + (1 – $p_{l,1c}$) – (1 – $p_{l,2c}$) , where P{X} represents the "probability of occurrence of X".

In addition, the analysis of one operating condition, i.e. 30-min snapshot, is divided into two discrete time windows for all operating states: the fast action or response time period (pf=1), i.e. right after the outage occurs and up to 10 minutes, and the slow action or reserve time window (pf=2), i.e. following 20 minutes. This allows the model to take account of both response and reserve actions from generation and to track the progress of all other variables whilst re-dispatch actions are taking place after a fault occurs.

To speed up the optimisation, this model uses linear DC power flow equations and an average unique generation size rather than real ones, e.g. 500 MW. Main equations are presented next.

3.3.3 Optimisation constraints

In each operating state, supply and demand must be balanced (Eq. 3.4).

$$\sum_{g=1..Ng} p_g^{c,pf} - \sum_{n=A,B} (itrp_n^c + \mathrm{pout}_n^{c,pf}) = \sum_{n=A,B} \mathrm{d}_n - \sum_{n=A,B} ll_n^{c,pf} \quad \forall c, pf \qquad \text{Eq. 3.4}$$

Eq. 3.5 ensures that there is no load shedding and no generation intertrips during intact condition (c=1).

$$\begin{aligned} &ll_n^{c=1,pf} = 0 \quad \forall pf, n \\ &itrp_n^{c=1} = 0 \quad \forall n \end{aligned} \qquad \text{Eq. 3.5}$$

Output of a generator must be between the minimum stable generation limit and the installed capacity of that generator. Reserve and response cannot exceed the installed capacity of the generator holding the services. These constraints are shown in Eq. 3.6.

$$\begin{aligned} &\underline{\mathrm{p}}_g \cdot \gamma_g \le p_g^{c,pf} \le \overline{\mathrm{p}}_g \cdot \gamma_g \quad \forall c, pf, g \\ &\gamma_g \text{ is binary } \forall g \\ &p_g^{c=1,pf} + nrsp_{\mathrm{g}} + nres_g \le \gamma_g \cdot \overline{\mathrm{p}}_{\mathrm{g}} \quad \forall \mathrm{g} \end{aligned} \qquad \text{Eq. 3.6}$$

Prior to running the O+X model, an unconstrained economic dispatch is run to determine the initial dispatch of generators based on fuel costs. Then, in the O+X model, it may be necessary to constrain generators off / on by accepting bids and offers in order to satisfy network constraints and to manage system risks. In Eq. 3.7, the volume of accepted bid and offer for a particular generator in an intact system is calculated.

$$p_g^{c=1,pf} = p_g^{ED} + off_g^{c=1} - bid_g^{c=1} \quad \forall pf, g \qquad \text{Eq. 3.7}$$

In Eq. 3.8 below, the bid or offer accepted is measured during a contingent state for generator g.

$$p_g^{c,pf=2} = p_g^{c=1,pf=2} + off_g^{c} - bid_g^{c} \quad \forall c \neq 1, g \qquad \text{Eq. 3.8}$$

Following a loss of production because of an unplanned outage (post-fault period pf=1), generators will respond. The amount of response from generator g is limited by its maximum response characteristics and the response that has been purchased to be available in this operating condition (Eq. 3.9).

$$\begin{aligned} & p_g^{c,pf=1} = p_g^{c=1,pf=1} + rsp_{\mathrm{g}}^{\mathrm{c}} \quad \forall c \neq 1, g \\ & rsp_{\mathrm{g}}^{\mathrm{c}} \leq \Delta \mathrm{rspup}_g \quad \forall c \neq 1, g \\ & rsp_{\mathrm{g}}^{\mathrm{c}} \leq nrsp_g \quad \forall c \neq 1, g \end{aligned} \qquad \text{Eq. 3.9}$$

Response will be used temporarily during pf=1. Generators need to be re-dispatched and reserve is used to balance again the supply and demand taking into account network constraints. The amount of reserve that can be utilised during contingency is limited by the amount that has been purchased/planned for this operating condition and also limited by the generator's characteristics such as ramp rate (up and down). These constraints are modelled in Eq. 3.10.

$$\begin{aligned} & p_g^{c,pf=2} \leq p_g^{c=1,pf=2} + res_g^c \quad \forall c \neq 1, g \\ & res_g^c \leq \Delta \mathrm{resup}_g \quad \forall c \neq 1, g \\ & res_{\mathrm{g}}^{\mathrm{c}} \leq nres_g \quad \forall c \neq 1, g \\ & p_g^{c,pf=2} \geq p_g^{c=1,pf=2} - \Delta \mathrm{resdwn}_g \quad \forall c \neq 1, g \end{aligned} \qquad \text{Eq. 3.10}$$

In all operating states, the power flows cannot exceed the rating of circuits. Pre-fault rating is used in intact system (c=1), short-run post-fault rating is used in c≠1 and pf=1, and long-run post-fault rating is used in c≠1 and pf=2 (Eq. 3.11).

$$-\bar{\mathrm{f}}^{c,pf} \leq f^{c,pf} = \sum_{g \in A} p_g^{c,pf} + ll_A^{c,pf} - (\mathrm{d}_A + itrp_A^c + \mathrm{pout}_A^{c,pf}) \leq \bar{\mathrm{f}}^{c,pf} \quad \forall c, pf \qquad \text{Eq. 3.11}$$

Intertrip is modelled as a linear variable (*itrp*) that can trip the optimal amount of generation output when it is necessary, e.g. in order to avoid thermal overloading of other circuits when outage happens at one or more network circuits. Intertrip is only used during contingent states which involve network circuit outages as shown in Eq. 3.12.

$$itrp_n^c \leq \sum_{g \in n} p_g^{c=1,pf=1} \quad \forall c \neq 1, n$$
$$itrp_n^c = 0 \quad \forall c \neq 1, n \text{ with no line outages}$$ Eq. 3.12

All variables can be zero or take positive values with the exemption of the power flow, $f^{c,pf}$.

This model has been developed in FICO Xpress with an Excel interface which has allowed the 3 GB transmission licensees[14] to run studies during the Fundamental Review of the SQSS[15].

3.4 The assessment: England – Scotland interconnector

3.4.1 System parameters and data

The 4-circuit England-Scotland interconnector is assessed along with future wind, conventional generation and demand backgrounds. The analysis considered various levels of wind output up to a total of 10 GW of wind generation connected in Scotland.

Annual outage rates for fair and adverse weather were populated and provided by the 3 GB transmission licensees. Value of Lost Load (VoLL), SPS utilisation prices, response and reserve prices represent typical values observed which correspond to 30 k£/MWh, 1k£ per MW tripped, 20 £/MW/h and 10 £/MW/h, respectively. Constraints prices are assumed to be cost-reflective, i.e. generators' outputs can be modified at a price equal to their fuel costs. Operating cost of each generator is represented through a constant marginal cost. Additionally, VoLL is fixed and does not vary across different consumer types. Figure 3.3 briefly shows a general scheme of the problem.

[14] National Grid, Scottish Power and Scottish and Southern Energy

[15] The aforementioned review was commissioned by Ofgem in order to identify the flaws and the potential room for improvements in the current deterministic security standards.

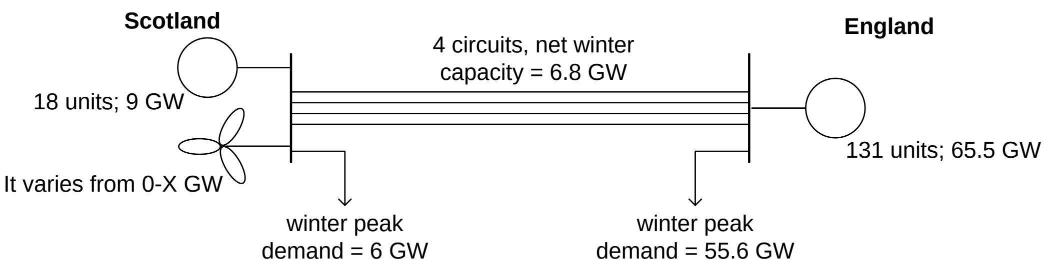

Figure 3.3: Simplified electric diagram of the analysed example

The 4 circuits are symmetric and their line rating is 1.7 GW (each circuit in winter) which is adjusted per season according to the following multiplying factors: 1 for winter, 0.85 for spring and autumn, and 0.7 for both summers.

Generation technologies modelled along with their capacities, availabilities, prices and further relevant information is presented in Table 3.1.

Table 3.1: Generation data – (1) installed capacity in Scotland -No.units; (2) installed capacity in England - No.units; (3) fuel cost -£/MWh; (4) bid price -£/MWh; (5) offer price -£/MWh; (6) maximum response per unit - MW; (7) maximum reserve per unit -MW; (8-11) winter/spring/summer/autumn generation availability -%

Generation Technology	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Wind	3	0	0	-50	N/A	0	0	N/A	N/A	N/A	N/A
Nuclear	5	17	0	-100	N/A	0	0	88%	85%	79%	73%
CHP	0	3	0	-50	N/A	0	0	73%	67%	57%	58%
Base Gas	0	24	30	30	30	50	200	96%	90%	78%	92%
Base Coal	1	27	35	35	35	50	200	95%	87%	80%	90%
Interconnector	0	4	50	50	50	0	0	99%	99%	91%	99%
Water	2	0	80	80	80	50	200	98%	97%	77%	97%
Marginal Gas	3	21	90	90	90	50	200	96%	90%	78%	92%
Marginal Coal	6	23	100	100	100	50	200	95%	87%	80%	90%
Pump Storage	1	3	200	200	200	50	200	98%	97%	77%	97%
Oil	0	7	210	210	210	50	200	95%	94%	81%	94%
Peakers	0	2	300	300	300	50	200	95%	94%	81%	94%

The statistics of line failures used for the interconnector were calculated by the licensees according to an average value per km and considering a length for the targeted boundary of 100 km. Table 3.2 shows their results.

Table 3.2: Faults rates and outage probabilities

	Single circuit		Double circuit		Generation
	Fair weather	**Adverse weather**	**Fair weather**	**Adverse weather**	**All weather**
Fault rate (occ/day)	1.4E-03	4.6E-02	1.4E-04	4.6E-03	4.9E-02
Lead time (h)	0.5	0.5	0.5	0.5	0.5
Pr	2.9E-05	9.5E-04	2.9E-06	9.5E-05	1.0E-03

In the following simulations, both of the following were considered: (a) certain values of wind outputs for a given operating conditions (e.g., analysis in sections 3.4.2.1, 3.4.2.2, 3.4.2.3, 3.4.2.5 and 3.4.2.8); and (b) uncertain wind availability (e.g., analysis in Section 3.4.2.4). In the latter, the occurrence the 5 low frequency events scenarios (due to wind uncertainty) that can ultimately affect the amount of response and reserve held in the intact system (Figure 3.4) were considered.

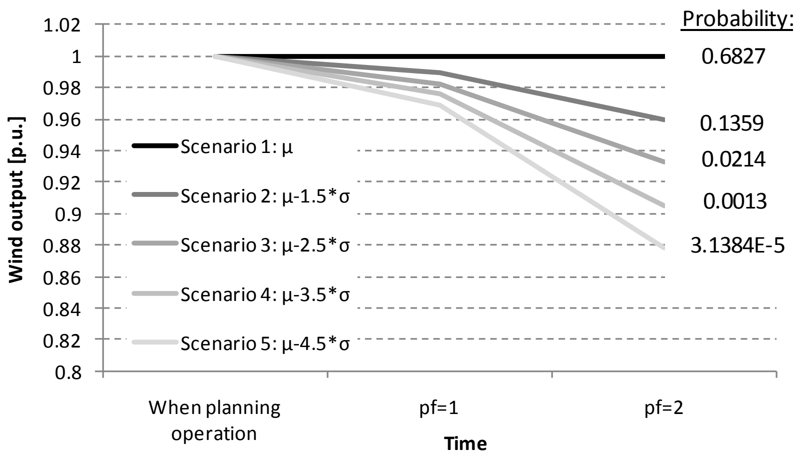

Figure 3.4: Wind forecast errors (when 1 p.u. indicates the expected wind output at the time when planning the operation)

To obtain the data shown in Figure 3.4, a simple forecast criterion was used that estimates the expected value of wind output during the next hour: wind outputs in t+30min (utilised for pf=1) and t+60min (utilised for pf=2) are expected to be equal to the wind output observed in t. The wind profile utilised for this exercise is depicted in Figure 3.5.

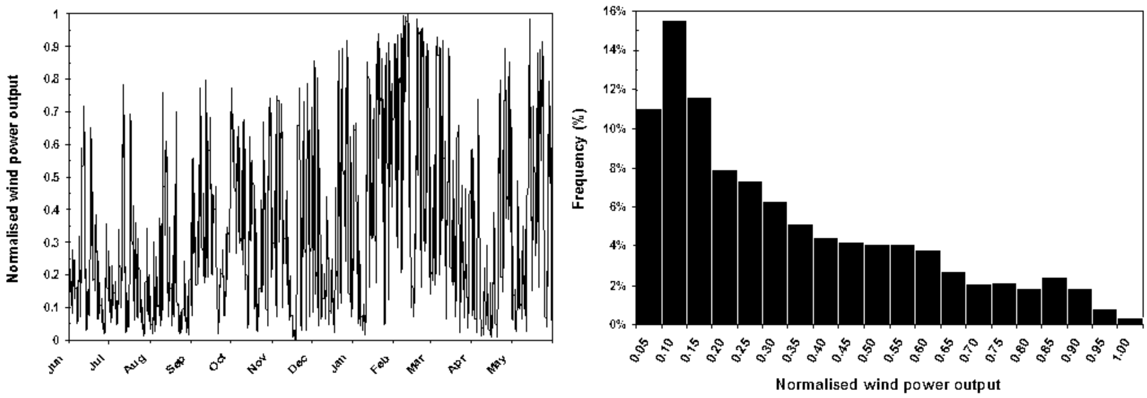

Figure 3.5: Annual wind profile (load factor of 30%)

3.4.1.1 Wind/demand scenario formation for year round studies

The 8,760 hours[16] are represented through 510 operating conditions or snapshots which combine: 5 typical days per season (summer intact, summer planned outage, winter, spring and autumn), 5 demand levels per day, 2 type of weather conditions (fair and adverse), 10 wind levels. In addition, an extra demand level was added in order to represent the peak demand condition, this considers only adverse weather and winter period along with 10 wind levels.

The difference between the two summers is that only 3 circuits are considered available during the summer planned outage period.

For the purpose of building the aforementioned 510 operating conditions, the wind profile used is that depicted in Figure 3.5 and the demand profile utilised is the one in Figure 3.6.

[16] In this exercise, a year of 365 days is considered.

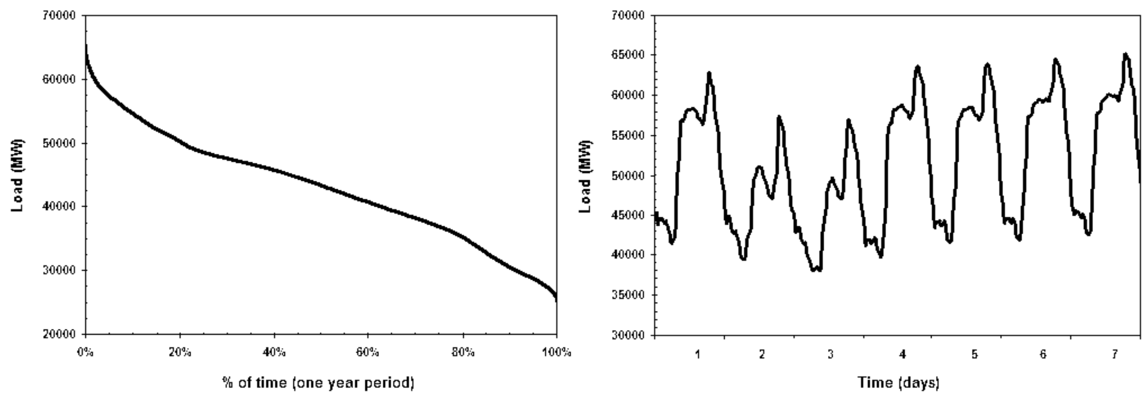

Figure 3.6: Yearly duration curve and load curve in the week of the peak demand (load factor 66%)

The weight (or durations) of each snapshot in the overall yearly O+X cost function represents: 5 weeks of summer intact, 8 weeks of summer planned outage and 13 weeks of winter, spring and autumn. Both summers contain a fair/adverse weather ratio of 97%/3%. Remaining seasons are composed of 88% and 12% of fair and adverse weather, respectively.

3.4.2 Results and analysis

In this section, a number of sensitivities are carried out. Also, year round studies are performed. The aim is to analyse main drivers for optimum power transfer and evaluate the efficiency of the current N-2 deterministic security policy.

3.4.2.1 Weather conditions

Weather conditions have been already identified in previous investigations as one of the important non-intrinsic equipment variables that can affect system security [55].

In this respect, Table 3.3 shows the total cost of network operation with different levels of power transfers across the simplified England-Scotland interconnector. It can be observed that the optimum balance of operating costs (O) and interruption costs (X) is achieved when power transfers are equal to 6.1 GW for fair weather condition and 4.4 GW for adverse weather condition. If transfers are limited at lower levels, the system operates at a higher operational cost (mainly driven by constraint costs). In contrast, if higher transfers are accepted, then the system is exposed to increased levels of risk.

Table 3.3: Net O+X cost for fair (a. left) and adverse weather (b. right) – 5.5 GW of wind output

Transfers MW	O	X	Total O+X
	£/30mins		
3,400	22,788	2,281	25,069
3,967	19,617	2,285	21,902
4,400	16,764	2,289	19,053
5,100	16,426	2,327	18,752
5,667	16,089	2,386	18,475
6,100	15,752	2,640	18,392
6,800	15,438	3,370	18,808

Transfers MW	O	X	Total O+X
	£/30mins		
3,400	22,788	2,306	25,095
3,967	19,618	2,381	21,999
4,400	16,796	2,645	19,440
5,100	16,518	3,877	20,395
5,667	18,787	3,077	21,864
6,100	19,222	4,546	23,768
6,800	22,551	5,625	28,176

For adverse weather conditions, it can be observed in Table 3.3 that the total operational costs increase when power transfers are above 5.1 GW. Although constraint costs reduce with increase in power transfer, increased levels of generation reserves (in this case) need to be held to support higher power transfers (this will be further elaborated in Section 3.4.2.3).

It is important to note that an N-2 deterministic rule, currently used in the UK, would limit power transfers to 3.4 GW, under all conditions.

3.4.2.2 Wind outputs

It is expected that about more than 10 GW of wind power will be connected in Scotland in the next decade. In this section the impact of wind outputs on the optimal power transfer between Scotland and England is analysed (Figure 3.7).

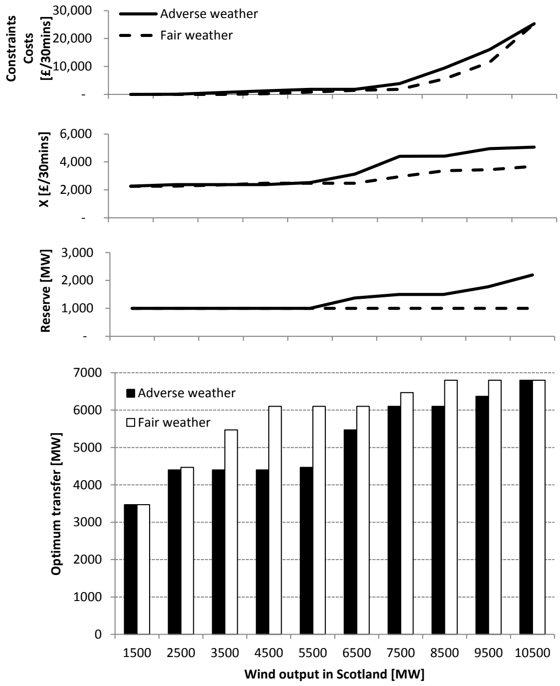

Figure 3.7: Optimum transfer, reserve, expected unsupplied demand cost and constraints cost for adverse and fair weather when considering various levels of wind output

It is observed that the optimal power transfer increases with the wind power output in order to prevent constraint costs escalating. However, it is also noted that levels of risk increase with higher wind power outputs in Scotland (due to an increased power transfer). Consequently, for high outputs of wind power the system will be exposed to greater risks (by allowing higher power transfer) in order to mitigate the increase in constraint costs (achieved again by allowing higher power transfers). In addition, to avoid excessive risk exposure during adverse weather, higher transfers are accompanied by the need to hold larger amounts of reserve plant.

This is in contrast with the present deterministic operating standards that would keep the power transfer at a single fixed level for all wind output conditions.

3.4.2.3 Generation and demand support

When accepting higher power transfers, not only does the expected cost of unsupplied demand increase but so too do some operational cost components such as generation reserve and/or SPS actions. Table 3.4 shows that to maintain an optimum cost balance whilst facilitating increased power transfer over the England-Scotland interconnector, both generation reserve commitments and SPS expected utilisation increase.

Table 3.4: Reserve commitments and expected generation and demand shed costs for adverse weather at different power transfers accepted – 5.5 GW of wind output

Transfers	Reserve	Generation shed	X
MW	MW	£/30mins	£/30mins
3,400	1,000	0	2,306
3,967	1,000	1	2,381
4,400	1,000	33	2,645
5,100	1,000	95	3,877
5,667	1,500	204	3,077
6,100	1,633	313	4,546
6,800	2,199	1,153	5,625

The increase in generation reserve scheduled to deal with outages of lines could reduce expected unsupplied demand levels at high levels of transfer. This means that higher power transfers do not necessarily drive higher operational risk when appropriate generation reserves (or equivalent demand side actions) are made available.

3.4.2.4 Wind uncertainty

The studies above are carried out on the assumption that wind outputs are perfectly predictable. In the following analysis wind uncertainty combined with uncertainties in generation and network availability are considered. It is observed that increased levels of generation reserve are committed (due to the presence of wind uncertainty) but also higher power transfers could be accepted. This demonstrates that there is a degree of reserve sharing in order to deal with generation uncertainty and transmission outages at the same time. In this respect, Figure 3.8 shows that higher power transfers can be accommodated in the England-Scotland interconnector due to the presence of extra generation reserve triggered by wind uncertainty. Reserve sharing levels vary with weather and wind conditions and needs to be located in the importing area to facilitate application of SPS.

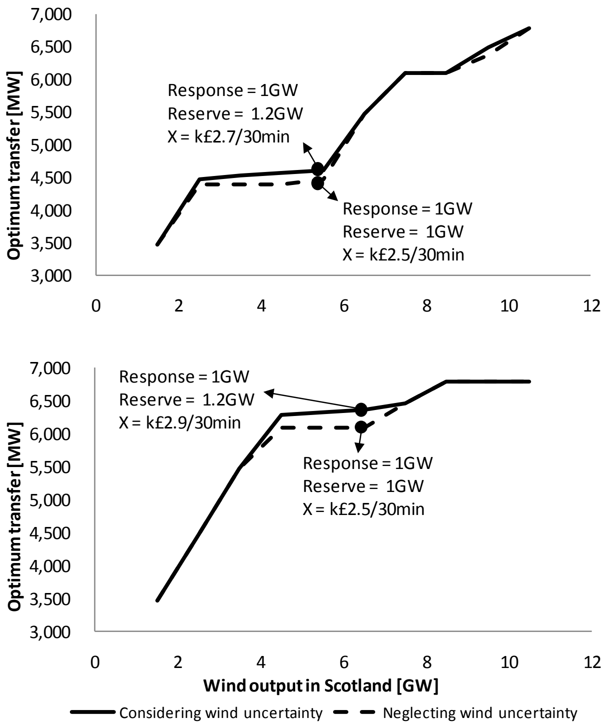

Figure 3.8: Optimum transfer for adverse (a. top) and fair weather (b. lower) with respect to wind outputs when considering wind uncertainty

It is important to note that there might be a correlation between weather condition and wind power availability which could impact power transfers (high wind outputs might be associated with adverse weather conditions).

3.4.2.5 System uncertainties

In addition to the uncertainties discussed above, there will be other uncertainties that are important to consider. For example, predicting weather is inherently uncertain. Furthermore, operation of SPS is associated with uncertainty as there might be failures on the communication system that lead to malfunctions of SPS and, in turn, to widespread disconnections of load. In this section analysis of the impact of these uncertainties on power transfers is presented.

The robustness of the decision to allow particular power transfers under uncertainty of weather conditions is analysed and presented in Table 3.5. Total expected costs, for two specific power transfer levels of 4.4 and 6.1 GW are presented that consider various degrees of confidence regarding weather conditions. If, for example, it is 100% certain that the weather will be adverse, the optimal power transfer should be set at 4.4 GW. On the other hand, if weather is fair with 100% certainty, the optimal power transfer could be increased to 6.1 GW. It is possible to observe from Table 3.5 that a higher power transfer of 6.1 GW could be permitted if the probability of having fair weather is higher or equal to 90%.

Table 3.5: Robustness of decisions when considering uncertainties in the prediction of weather conditions -5.5 GW of wind output

Probability (%) of		Expected cost (£/30min) of operating at	
fair weather	adverse weather	6.1 GW (and 1 GW of reserves)	4.4 GW (and 1 GW of reserves)
0	100	24,699	19,440
5	95	24,383	19,421
10	90	24,068	19,402
15	85	23,753	19,382
20	80	23,438	19,363
25	75	23,122	19,344
30	70	22,807	19,324
35	65	22,492	19,305
40	60	22,176	19,286
45	55	21,861	19,266
50	50	21,546	19,247
55	45	21,230	19,228
60	40	20,915	19,208
65	35	20,600	19,189
70	30	20,284	19,169
75	25	19,969	19,150
80	20	19,654	19,131
85	15	19,338	19,111
90	10	19,023	19,092
95	5	18,708	19,073
100	0	18,392	19,053

Table 3.5 is computed when taking account of Eq. 3.13.

$$C\{Z\} = C\{Z|\text{ adverse weather}\}\, P\{\text{adverse weather}\} + C\{Z|\text{ fair weather}\}\, P\{\text{fair weather}\} \qquad \text{Eq. 3.13}$$

Where C{Z} is the expected cost of Z, C{Z| Y} is the conditioning expected cost of Z given Y, and Z represents the operation of the system when transferring 6.1 GW or 4.4 GW.

Additionally, other uncertainties like malfunctions of SPS or the presence of hidden failures (failures that remaining unrevealed under normal system conditions [57,58]) can be also assessed within the proposed cost-benefit framework. Figure 3.9 shows optimum transfers for different levels of probability of system malfunctions and the extra demand which may be curtailed above the optimum levels due to malfunctions or if cascading outages occur[17]. This shows how the power transfers become more constrained when the probability of having malfunctions increases.

[17] Response and reserve availability were fixed according to the optimum transfer conditions, i.e. 1 GW of each service during fair weather, and 1 and 1.5 GW of response and reserve during adverse weather.

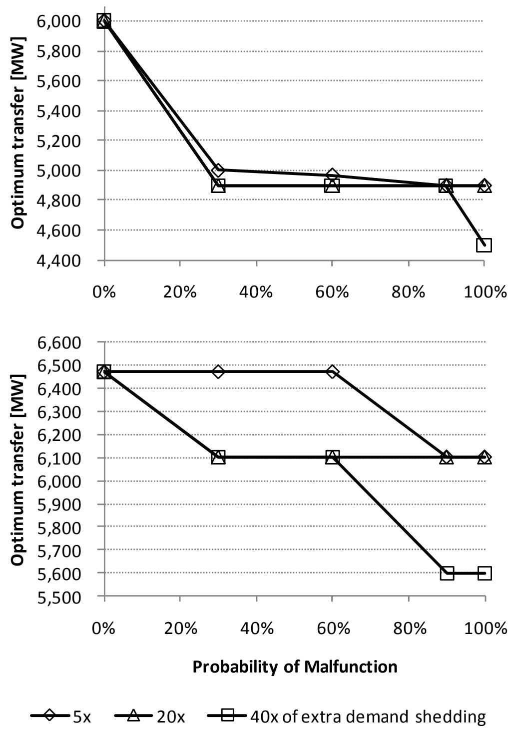

Figure 3.9: Optimum transfer when considering malfunction events for adverse (a. top) and fair (b. lower) weather – 7.5GW of wind installed capacity

Notice that even for a high probability of malfunctions (100%) together with large amounts of non-optimum demand shedding (40 times the optimum amount of demand shedding), the optimum transfers remain above the limit given by an N-2 deterministic policy, i.e. 3.4 GW.

3.4.2.6 Sensitivity of prices

As the optimum transfer directly depends on a cost-benefit balance, prices may play an important role; higher levels of redundancy might be difficult to justify in the presence of higher prices of constraints and, in contrast, economically used when alternatives resources to secure system operation such as response, reserve and intertripping are more expensive. From an array of sensitivities, it can be proven that this framework is robust against credible variations in market prices and, in fact, the impact on the amount of power transferred is smaller than those observed under weather or/and wind sensitivities as shown in Table 3.6.

Table 3.6: Price sensitivity for power transfer – 7.5 GW of wind installed capacity

Price range indicated between [;]	Flow variation range indicated between [;] Fair weather	Adverse weather
Offer-bid price difference of the same generation technology [1; 80] £/MWh	[6.5; 6.8] GW	[6.1; 6.8] GW
Availability price of response & reserve [10; 40] & [5; 20] £/MW/h	[6.6; 6.5] GW	[6.1; 5.6] GW
Utilisation price of intertrip [100; 10,000] £/MW/event	[6.5; 6.5] GW	[6.1; 6.0] GW

3.4.2.7 When is an N-2 policy optimum?

The studies above demonstrate that a N-2 strict security limit is likely to be uneconomical at the peak demand and with high wind penetration. An alternative way to illustrate this is to find the VoLL that can justify the present levels of redundancy, i.e. *what should the minimum VoLL be in order to justify a strict deterministic N-2 policy in the England-Scotland interconnector?* Results are shown in Table 3.7 for various wind outputs and weather condition.

Table 3.7: Minimum VoLL to justify an N-2 transfer policy type

	Critical VoLL to justify N-2 [£/MWh] Fair weather		Adverse weather	
	Generation based services available	Generation based services unavailable	Generation based services available	Generation based services unavailable
Wind output of 5.5 GW	>50,000,000	2,950,000	13,000,000	100,000
Wind output of 7.5 GW	>50,000,000	27,000,000	>50,000,000	810,000
Wind output of 9.5 GW	>50,000,000	27,000,000	>50,000,000	810,000

Table 3.7 shows that the VoLL has to be very high, i.e. >> 30 k£/MWh and ranging from 100 k£/MWh to >50 M£/MWh for transmission redundancy equal to N-2 to be remunerated. This is especially so when wind penetration becomes higher and in the presence of generation-based services (i.e. response and reserve) that can contribute to system security though post-fault actions and minimise the utilisation of demand shedding as a corrective action.

3.4.2.8 Developing a business case for the introduction of probabilistic security standards: yearly impact assessment

The overall cost of operation (O) and expected unsupplied demand (X) have been assessed by considering a whole year of system operation under three different power transfer policies; (i) optimum probabilistic, (ii) N-2 deterministic (present GB standard), and (iii) N-1 deterministic.

Figure 3.10 summarises the key findings of this exercise for two different wind penetration levels. As expected, it is observed that the benefits of probabilistic approach to determining power transfers (measured annual operating cost savings) are more significant for high levels of wind penetration. It can be noted that that for high wind penetration (Figure 3.10b) the cost across the three different transfer policies analysed vary significantly, whilst smaller changes are observed for lower wind penetration levels (Figure 3.10a). In addition, changes in the cost of constraints are more significant than changes in the costs of generation-based services and expected unsupplied demand.

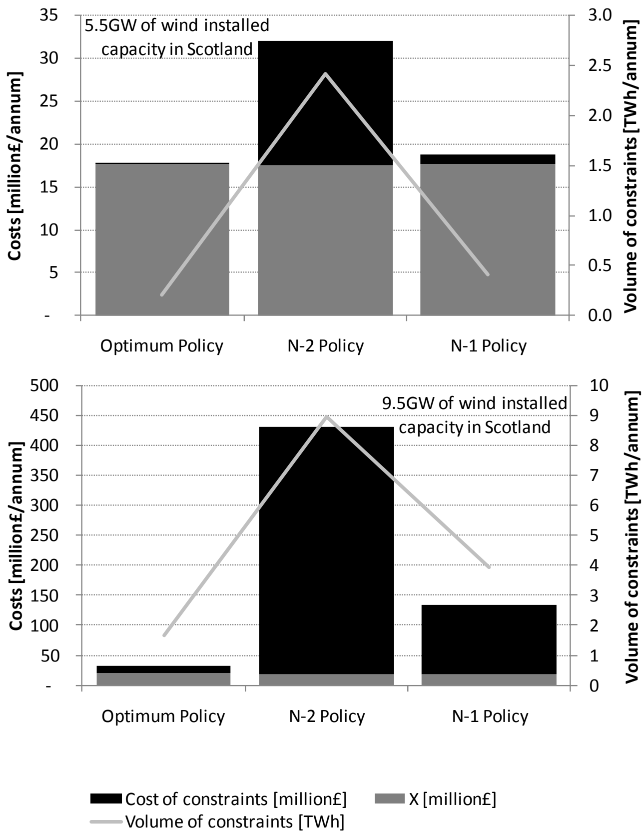

Figure 3.10: Annual operational costs and volume of constraints under different transfer policies, i.e. under different transmission upper limits, for 5.5 GW (a. top) and 9.5 GW (b. lower) of wind installed capacity

Figure 3.10 also shows that the cost of constraints increases much more rapidly than the volume of energy constrained. This is so because the marginal cost of constraints, i.e. England-Scotland energy marginal price differential, rises as the volume of constraints increases, especially under high wind penetration. This ultimately fosters higher network utilisations and the increased use of post-fault actions centred on generation-based resources to guarantee system security on a continuous basis.

3.4.3 Limitation of the case studies

The results obtained suggest that there is potentially a large benefit of moving away from the current deterministic security framework. However, the presented results should be taken in the context of a number of simplifying assumptions made. The actual value of the probabilistic approach in any particular system will be affected by several factors such as: increased amount of losses that will be accompanied with increased power transfers; the development of demand response policies which may reveal more information with respect to VoLL across different consumer types; VoLL that may vary widely across different consumer types; the effect of dynamic or stability constraints that will become increasingly more important with increased power transfers; application of dynamic line ratings; correlation of weather and wind generation condition. Conceptually, however, these effects could be integrated within the probabilistic operational standards and this is recommended for future investigations.

3.5 Conclusions

It has been shown through a boundary network model that power transfers can be efficiently secured by a number of coordinated pre- and post-fault actions from generation, transmission and demand. The application of the probabilistic cost-benefit approach to the simplified England-Scotland interconnector suggests that the network capacity that can be optimally released to users changes significantly depending on actual system conditions. These include: level of constraints cost associated with a particular operating condition that would be driven by the levels of wind power output (that varies significantly); weather conditions that are also variable and can be optimised to take account of cost of generation reserves and costs of corrective demand actions (that may be voluntary and involuntary). Furthermore, studies show that any attempt to fix a single generic value for maximum network utilisation, as in the present standards, will lead to inefficiencies, limiting the amount of capacity that can be released to network users, particularly during fair weather conditions.

All these demand urgent review of the current security standards given the need to facilitate a cost-effective evolution to a low carbon energy system through exploiting various smart grid technologies that are critical for the efficient integration of large amounts of wind generation.

CHAPTER 4: Transmission network models for integrated reliability and cost-benefit operation and planning

Abstract

In light of the concepts previously introduced in Chapter 3, the 2-busbar model is extended to cope with meshed and larger transmission networks. In the present chapter, the formulation is also extended in order to deal with network planning. Issues related to the computational burden caused by the large-scale size of the probabilistic optimisation are addressed.

This chapter develops a new two-stage probabilistic optimisation model for the operational and planning problems by means of a Benders algorithm. The model is able to balance network redundancy levels against the use of operational measures by minimising costs and risks in every operating condition. To reduce the computational times and memory usage, a novel filtering technique to identify the relevant (or umbrella) contingencies is presented and tested.

The proposed model is used in this chapter to scrutinise 2 numerical examples where the impact is assessed on network utilisation and enhancements of a set of pre and post-fault operational measures such as constraints levels, operating reserves allocation and the use of Special Protection Schemes (SPS). All probabilistic results are benchmarked against the ones obtained through an analogous deterministic model in order to highlight the difference between both approaches.

The benchmark study demonstrates that deterministic standards will lead to potentially significant inefficiencies and even to potentially risky network operation and design. The benchmark also shows that these problems can be corrected by using a probabilistic approach for network security.

4.1 Chapter's nomenclature

4.1.1 Parameters

Parameters' names are all set in normal font.

$\mathrm{B}^{-1c}_{n,k}$	N,k element of the inverse of the admittance matrix (i.e. only imaginary part) in operating state c	p.u.
C^{inv}_{l}	Investment cost of line l	\$/yr
d_{n}	Demand in node n	MW
fac^{pf}	Ratio of the post- fault line rating divided by the pre-fault one (same for every circuit).	
$\mathrm{n}_1(\mathrm{l}),\mathrm{n}_2(\mathrm{l})$	End nodes of line l	
OX_{i}	Summation of all operational costs and risks over the entire year in the i-th Benders iteration	\$/yr
$\underline{\mathrm{p}}_g, \overline{\mathrm{p}}_g$	Minimum stable generation and maximum output of generator g	MW
$\mathrm{p}^{\mathrm{ED}}_{\mathrm{g}}$	Unconstrained dispatch of generator g	MW
ref	The reference node for the DC power flow calculations (usually written like n=ref)	
voll_{n}	Value of lost load at node n	\$/MWh
w	Duration of the standardized timeframe of all operating conditions (e.g. 0.5 h)	h
x_{l}	Reactance value of line l	p.u.
$\Delta\mathrm{resu}_{g}$	Net ramping up limit for generator g during the first 10 minutes of the standardised time window	MW
$\Delta\mathrm{resd}_{g}$	Net ramping down limit for generator g during the first 10 minutes of the standardised time window	MW
λ_{i}	Failure rate of individual network component i	occ/h
$\pi\mathrm{bid}_{g}$	Bid price submitted by generator g	\$/MWh
$\pi\mathrm{off}_{g}$	Offer price submitted by generator g	\$/MWh
$\pi\mathrm{resh}_{g}$	Price of holding reserve services provided by generator g	\$/MW/h

$\pi \mathrm{resuu}_g$	Utilisation price of reserve up services provided by generator g	\$/MWh
$\pi \mathrm{resud}_g$	Utilisation price of reserve down services provided by generator g	\$/MWh
$\pi \mathrm{itrp}_g$	Utilisation price of inter-tripping scheme provided by generator g (per event)	\$
ρ^c	Probability of occurrence of operating state c	p.u.
${}^s\tau$	Total duration of the operating condition s in a year	h

4.1.2 Variables

Variables' names are all set in *italic* font.

bid_g	Accepted bid from generator g	MW
f_l^c	Power flow in line l at operating state c	MW
$\overline{f}_l^c$	Line rating of circuit l at operating state c. As a parameter (where i corresponds to the i-th Benders iteration): $\overline{\mathrm{f}}_l^{*c}$ or $\overline{\mathrm{f}}_{l,i}^{*c}$	MW
$itrp_g^c$	Tripping of generator g at operating state c by a SPS. 1 if tripped, 0 otherwise. As a parameter (where i corresponds to the i-th Benders iteration): itrp_g^{*c} or $\mathrm{itrp}_{g,i}^{*c}$	binary
$itrpu_g^c$	Power tripped of generator g at operating state c by a SPS	MW
ll_n^c	Loss of load at node n at operating state c	MW
off_g	Accepted offer from generator g	MW
p_g	Output of generator g	MW
$resh_g$	Accepted reserve service from generator g	MW
$resuu_g^c$	Utilised reserve up service from generator g at operating state c	MW
$resud_g^c$	Utilised reserve down service from generator g at operating state c	MW
z	Master subproblems' variable in Benders	\$/yr
γ_g	Scheduling status of generator g. 1 if on, 0 otherwise. As a parameter (where i corresponds to the i-th Benders iteration): γ_g^* or $\gamma_{g,i}^*$	binary

${}^{s}\lambda^{c}_{x,y,i}$	Lagrange multiplier of constraint x of line/generator y at operating state c in operating condition s at the i-th Benders iteration	\$/MW
θ^{c}_{n}	Angle of node n at operating state c	rad

A parameter that is also used as a variable is generally marked with a subscript *.
As this chapter studies generic examples rather than a particular country's network, $ is used for currency.

4.2 Introduction

Currently, operational and planning decisions on Main Interconnected Transmission Systems (MITS) mainly rely on the outcomes of a Security Constrained Optimum Power Flow (SC-OPF) problem. The SC-OPF is a natural extension of the OPF problem which determines not only an economic dispatch but also a reliable one by securing the operation against a set of prescribed contingencies [23, 59-62]. SC-OPF based models are used by several Transmission System Operators (TSOs) for network operation and planning as well as for network pricing purposes. Furthermore, the Locational Marginal Prices (LMP) of electricity in markets like PJM or New England are calculated by using these models [63].

Probabilistic OPF (P-OPF), on the other hand, is a modification of the SC-OPF which in principle solves the same problem (i.e. optimum dispatch with account taken of security) but attempts to tackle the imperfections of the SC-OPF. In effect, various studies have arisen that demonstrate several benefits of carrying out probabilistic analyses over deterministic ones [19,64,65]. The aim is to show that probabilistic frameworks are more efficient than deterministic ones as the former measure the real risks caused by their actions and balance them against costs. A comprehensive survey about SC-OPF and P-OPF models can be found in [32].

In addition to the discussion presented in chapters 2 and 3, in this chapter three further critical aspects are addressed that advocate for moving towards probabilistic based network standards.

1. Lately, there has been significant progress in optimisation and computational tools as well as in probabilistic algorithms and concepts. In particular, the following is shown:
    a. how simple algorithms (that are complementary to the operational, i.e. O+X, and planning, i.e. T+O+X, optimisations) can be incorporated in order to reduce the computational burden.

   b. how the use of multi-threading libraries available in commercial optimisation languages (e.g. mmjobs in FICO) and the use of multi-cores computers can speed up the calculations in a Benders environment.

2. There is an increasing need to couple network planning with actual network operation. Usually deterministic planning takes account of only a few operating conditions (i.e. the most critical or peak demand condition) and therefore there is no real consideration of the full costs and benefits over a comprehensive set of scenarios (that represents all possible network states in a year) when evaluating and deciding on transmission investment. This is a key aspect in the presence of new network technology which can deliver additional network capacity through operational measures (e.g. reallocating generation reserves), displacing the need for costly network enhancements.

3. Deterministic rules can actually drive risky operation under particular circumstances. Furthermore, in planning timescales these rules can lead to both: (a) an overinvestment and (b) the enhancements of the wrong network assets (i.e. deterministic rules can end up enhancing assets that do not need to be enhanced and vice versa). Since deterministic methods claim to be more secure and still reasonably efficient, the aforementioned weaknesses need to be proved and properly understood.

In the next sections, a P-OPF model is derived which incorporates points 1 and 2 above and illustrates the problems mentioned in point 3.

4.3 The model for assessment

4.3.1 General overview

The general model is basically a combined operational, planning and filtering (contingencies-selection) module. In the operational module, optimal operating decisions (and so optimum network utilisation) over a given set of operating conditions are determined. The planning module, supported by multiple executions of the operational module over a variety of operating conditions, determines: (i) the optimum network investment in a year, (ii) the optimum generation commitments in each operating condition, and (iii) the utilisation level of SPS in each operating state. The operating and planning decisions are coordinated through a Benders algorithm. The filtering module serves to lower the number of operating states (i.e. contingencies) considered in the analysis of each operating condition. These 3 modules are coordinated as shown in Figure 4.1.

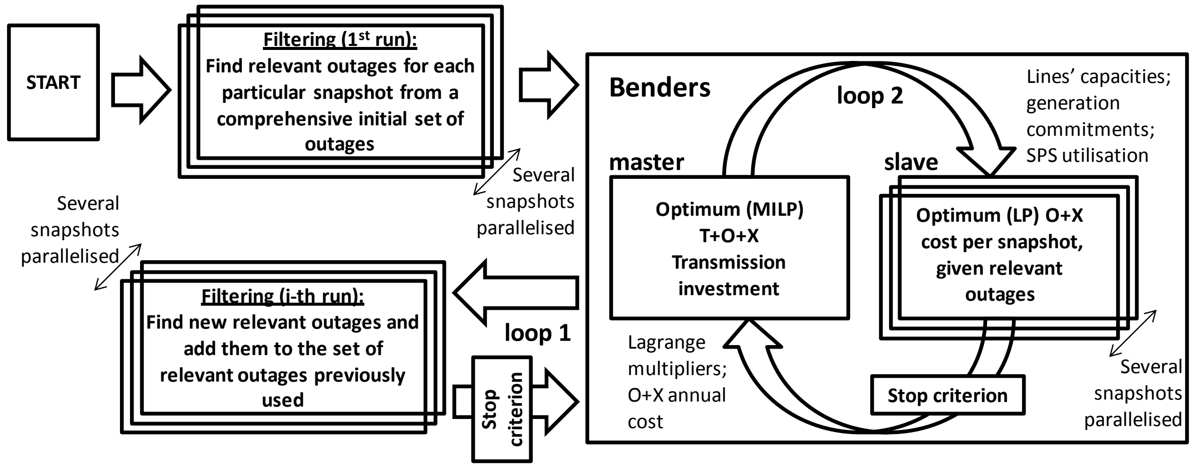

Figure 4.1: General algorithm with 3 modules

The filtering module is applied iteratively as follows:

- deriving the relevant outages over the initial network for each operating condition (1st run in Figure 4.1);
- deriving the relevant outages over the enhanced network for each operating condition, and adding these outages (if not included) to the previously derived set of relevant outages (i-th run in Figure 4.1).

The Benders algorithm (loop 2) stops according to the general criterion explained in [66] which is when the upper (Z_upper) and lower (Z_lower) estimations of the overall transmission cost function (i.e. investment + operation + unsupplied demand –T+O+X–) are (nearly) equal.

Loop 1 stops if there are no more outages to be added to the set of relevant outages given the latest sets of transmission network capacities and generation outputs.

To reduce the potentially massive computational burden, parallel threading is used together with the algorithm explained in Section 4.3.3.1. Figure 4.1 also shows how different operating conditions can be run in parallel.

4.3.2 The operational module: disclosing optimum network utilisation (O+X)

The proposed model derives the optimum power transfers by balancing the cost of the transmission constraints (caused by the aforementioned power transfers) against the cost of several pre- and post-fault operational measures. This is done on a single operating condition basis. The operational measures considered are:

1. System balancing. Power flows can be controlled via generation balancing actions in order to mitigate circuit overloading while maintaining the supply and demand balance at all times.

2. Commitment and utilisation of generation reserve. Different levels of generation reserve can be committed in the pre-fault condition (via balancing actions) to better cope with outage events in a post-fault condition. In this model, generation reserves can be committed and utilised in order to deal with outages not only of generating plants but also of transmission circuits. Consequently, reserve allocation has to facilitate the application of SPS. The reserve can be provided by synchronized generators or stand-by units that can be synchronised in few minutes.

3. Exercise of SPS to shed generation and/or demand. Following an outage of a circuit, SPS automatically disconnects (or instigate rapid reduction of) generation and/or demand in exporting and importing areas respectively to avoid post-fault network overloads. This allows System Operators (SOs) to accept more power transfers in the intact system or pre-fault condition.

Therefore, the objective function of the proposed operational model has to balance all these costs and expected costs as shown in Eq. 4.1. This is, essentially, the same objective function as presented in Chapter 3 for the 2-busbar model, but slightly simplified in order to cope with a larger number of nodes and branches (e.g. only generation reserve and not response is modelled).

$$Min\left\{\begin{array}{l}\sum\limits_{g=1..Ng}\left\{\mathrm{w}\cdot(\pi\mathrm{off}_g\cdot off_g-\pi\mathrm{bid}_g\cdot bid_g+\pi\mathrm{resh}_\mathrm{g}\cdot resh_g)\right\}+\\ \sum\limits_{\substack{c=2..Nc\\ g=1..Ng}}\left\{\mathrm{w}\cdot\rho^\mathrm{c}\cdot(\pi\mathrm{resuu}_\mathrm{g}\cdot resuu_g^c+\pi\mathrm{resud}_\mathrm{g}\cdot resud_g^c)\right\}+\\ \sum\limits_{\substack{c\text{ with line trips}\\ g=1..Ng}}\left\{\rho^\mathrm{c}\cdot\pi\mathrm{itrp}_\mathrm{g}\cdot itrp_g^c\right\}+\sum\limits_{\substack{c=2..Nc\\ n=1..Nn}}\left\{\mathrm{w}\cdot\rho^\mathrm{c}\cdot\mathrm{voll}_n\cdot ll_n^c\right\}\end{array}\right\} \qquad \text{Eq. 4.1}$$

In the model, the first operating state is the intact system (c=1) and this is coupled with all considered contingent states because the post-fault generation re-dispatches must consider the intact system operation as an initial condition. From the intact system condition to a post-fault one, generation outputs and demand can be changed taking into account the ramp rate limits, SPS actions and the operating reserves committed during the intact system. In addition, line ratings can be considered temporarily larger during post-fault conditions. The model considers that all operating actions occur within a standardised timeframe with duration of w minutes.

Given that the dispatch is based on a net pool market, net increases (offer volumes) and decreases (bid volumes) of generation output are measured against the physical position of every generator previously obtained by running a simple economic or unconstrained dispatch that does not consider network and risk constraints (i.e. a simple merit order). This is shown in Eq. 4.2. A positive $\pi\mathrm{off}_g$ – $\pi\mathrm{bid}_g$ differential in the objective function will ensure that bids and offers are not simultaneously accepted for a single generator.

$$p_g = p_g^{ED} + off_g - bid_g \quad \forall g \qquad \text{Eq. 4.2}$$

Generation outputs and volumes of bids and offers have to be within feasible ranges as shown by Eq. 4.3-4.7.

$$\underline{\mathrm{p}}_g \cdot \gamma_g \le p_g \le \overline{\mathrm{p}}_g \cdot \gamma_g \quad \forall g \qquad \text{Eq. 4.3}$$
$$\gamma_g \text{ is binary } \forall g \qquad \text{Eq. 4.4}$$
$$p_g \le 0 \quad \forall g \text{ in maintenance} \qquad \text{Eq. 4.5}$$

$$off_g \le \overline{\mathrm{p}}_g - p_g^{ED} \quad \forall g \qquad \text{Eq. 4.6}$$
$$bid_g \le p_g^{ED} \quad \forall g \qquad \text{Eq. 4.7}$$

A critical characteristic of the probabilistic framework that impacts on network utilisation is the use of corrective actions: in order to have reserve available for re-dispatching purposes, it must be committed in advance (Eq. 4.8-4.12); and SPS can only shed the entire production of a generating unit (Eq. 4.13-4.14). The limitation of using reserve down services over a tripped generation unit is represented through Eq. 4.15.

$$resh_g \le \overline{\mathrm{p}}_g - p_g \quad \forall g \qquad \text{Eq. 4.8}$$
$$resh_g \le \Delta\mathrm{resu}_g \cdot \gamma_g \quad \forall g \qquad \text{Eq. 4.9}$$

$$resuu_g^c \le resh_g \quad \forall c, g \qquad \text{Eq. 4.10}$$
$$resud_g^c \le \Delta\mathrm{resd}_g \quad \forall c, g \qquad \text{Eq. 4.11}$$
$$p_g - resud_g^c \ge \underline{\mathrm{p}}_g \cdot \gamma_g \quad \forall c, g \qquad \text{Eq. 4.12}$$

$$p_g - itrpu_g^c \le \overline{\mathrm{p}}_g \cdot (1 - itrp_g^c) \quad \forall c, g \qquad \text{Eq. 4.13}$$
$$itrpu_g^c \le \overline{\mathrm{p}}_g \cdot itrp_g^c \quad \forall c, g; \text{ where } itrp_g^c \text{ is binary } \forall c, g \qquad \text{Eq. 4.14}$$

$$resud_g^s \le p_g - itrpu_g^s \quad \forall s, g \qquad \text{Eq. 4.15}$$

All other constraints represent typical equalities and inequalities of an Optimum Power Flow (OPF) exercise with transmission constraints such as:

(i) the supply-demand balance in pre- and post-fault conditions (Eq. 4.16-4.18);

$$\sum_{g=1..Ng} p_g = \sum_{n=1..Nn} \mathrm{d}_n - \sum_{n=1..Nn} ll_n^{c=1} \qquad \text{Eq. 4.16}$$

$$\sum_{g \text{ functioning in } c} p_g + resuu_g^c - resud_g^c - itr_g^c = \sum_{n=1..Nn} \mathrm{d}_n - ll_n^c \quad \forall c = 2..Nc \qquad \text{Eq. 4.17}$$
$$resuu_g^c = 0; resud_g^c = 0; itr_g^c = 0 \quad \forall c = 2..Nc, g \text{ outaged} \qquad \text{Eq. 4.18}$$

(ii) the angle equations considering a linearised (DC) power flow (Eq. 4.19-4.20);

$$\theta^{c}_{n=ref} = 0 \quad \forall c \qquad \text{Eq. 4.19}$$

$$\theta^{c}_{n} = \sum_{\substack{k=1..Nn \\ k\neq ref}} \left[\left(\sum_{\substack{g \text{ functioning} \\ \text{at node k in c}}} (p_g + resuu^c_g - resud^c_g - itr^c_g) + ll^c_k - \mathrm{d}_k \right) \cdot \mathrm{B}^{-1\,\mathrm{c}}_{n,k} \right] \forall c, n \neq ref \qquad \text{Eq. 4.20}$$

(iii) and the power flow per line along with its physical limits (Eq. 4.21-4.23)

$$f^{c}_{l} = \frac{\theta^{c}_{n_1(l)} - \theta^{c}_{n_2(l)}}{\mathrm{x}_l} \quad \forall c, l \text{ neither in maintenance nor outaged} \qquad \text{Eq. 4.21}$$

$$-\overline{\mathrm{f}}^{c}_{l} \leq f^{c}_{l} \leq \overline{\mathrm{f}}^{c}_{l} \quad \forall c, l \text{ neither in maintenance nor outaged} \qquad \text{Eq. 4.22}$$

$$f^{c}_{l} = 0 \quad \forall c, l \text{ in maintenance or outaged} \qquad \text{Eq. 4.23}$$

This formulation corresponds to a Mixed Integer Linear Programming (MILP) problem if the operational module is run in isolation from the planning module, for example, to analyse a single operating condition. Instead, this formulation corresponds to a Linear Programming (LP) problem if generation commitments and SPS utilisation levels are imported from the planning module during the application of the Benders algorithm. In this case the operational module becomes a slave subproblem and the SPS cost can be ignored in Eq. 4.1.

4.3.3 The planning module: disclosing optimum network enhancement (T+O+X)

In planning timescales, the impact of transmission expansions on operating cost and risk is measured for each individual operating condition and summed over the entire year in order to determine the optimum set of network capacities. This is required to determine the efficient levels of transmission investment balanced with other operating measures as discussed earlier.

For each operating condition where the operational module (i.e. a slave subproblem) is executed, the Lagrange multipliers associated with the following constraints are exported to the master subproblem: lower and upper bounds of lines' capacity (Eq. 4.24-4.25); minimum and maximum generation capacities (Eq. 4.26-4.27); maximum generation reserve holding levels and maximum generation reserve down utilisation (Eq. 4.28-4.29); and utilised and unutilised status of SPS (Eq. 4.30-4.31).

$$f_l^c \geq -\overline{\mathrm{f}}_l^{*c} \quad \forall c,l \rightarrow {}^s\lambda_{1,l,i}^c \qquad \text{Eq. 4.24}$$

$$f_l^c \leq \overline{\mathrm{f}}_l^{*c} \quad \forall c,l \rightarrow {}^s\lambda_{2,l,i}^c \qquad \text{Eq. 4.25}$$

$$p_g \leq \overline{\mathrm{p}}_g \cdot \gamma_g^* \quad \forall g \rightarrow {}^s\lambda_{3,g,i} \qquad \text{Eq. 4.26}$$

$$-p_g \leq -\underline{\mathrm{p}}_g \cdot \gamma_g^* \quad \forall g \rightarrow {}^s\lambda_{4,g,i} \qquad \text{Eq. 4.27}$$

$$resh_g \leq \Delta\mathrm{resu}_g \cdot \gamma_g^* \ \forall g \rightarrow {}^s\lambda_{5,g,i} \qquad \text{Eq. 4.28}$$

$$p_g - resud_g^c \geq \underline{\mathrm{p}}_g \cdot \gamma_g^* \ \forall c,g \rightarrow {}^s\lambda_{6,g,i}^c \qquad \text{Eq. 4.29}$$

$$p_g - itrpu_g^c \leq \overline{\mathrm{p}}_g \cdot (1-\mathrm{itrp}_g^{*c}) \ \ \forall c,g \rightarrow {}^s\lambda_{7,g,i}^c \qquad \text{Eq. 4.30}$$

$$itrpu_g^c \leq \overline{\mathrm{p}}_g \cdot \mathrm{itrp}_g^{*c} \ \ \forall c,g \rightarrow {}^s\lambda_{8,g,i}^c \qquad \text{Eq. 4.31}$$

Here the arrow (→) indicates a Lagrange multiplier associated with the constraint labelled by the specified index.

Given these multipliers, it is possible to write the master subproblems with the Benders (feasibility) cuts shown in Eq. 4.32.

$$\begin{aligned}
z \geq & \sum_{l=1..Nl} \mathrm{C}_l^{inv} \cdot \overline{f}_l^{c=1} + \sum_{\substack{c \text{ with line trips} \\ g=1..Ng \\ s=1..Ns}} {}^s\rho^c \cdot \pi\mathrm{itrp}_g \cdot {}^s itrp_g^c \cdot \frac{{}^s\tau}{\mathrm{w}} + \mathrm{OX}_i + \\
& \sum_{\substack{l=1..Nl \\ s=1..Ns}} (\overline{\mathrm{f}}_{l,i}^{c=1} - \overline{f}_l^{c=1}) \cdot {}^s\lambda_{1,l,i}^{c=1} \cdot \frac{{}^s\tau}{\mathrm{w}} + \sum_{\substack{c=2..Nc \\ l=1..Nl \\ s=1..Ns}} (\overline{\mathrm{f}}_{l,i}^{c=1} - \overline{f}_l^{c=1}) \cdot \mathrm{fac}^{pf} \cdot {}^s\lambda_{1,l,i}^c \cdot \frac{{}^s\tau}{\mathrm{w}} + \\
& \sum_{\substack{l=1..Nl \\ s=1..Ns}} (-\overline{\mathrm{f}}_{l,i}^{c=1} + \overline{f}_l^{c=1}) \cdot {}^s\lambda_{2,l,i}^{c=1} \cdot \frac{{}^s\tau}{\mathrm{w}} + \sum_{\substack{c=2..Nc \\ l=1..Nl \\ s=1..Ns}} (-\overline{\mathrm{f}}_{l,i}^{c=1} + \overline{f}_l^{c=1}) \cdot \mathrm{fac}^{pf} \cdot {}^s\lambda_{2,l,i}^c \cdot \frac{{}^s\tau}{\mathrm{w}} + \\
& \sum_{\substack{g=1..Ng \\ s=1..Ns}} ({}^s\gamma_g - {}^s\gamma_{g,i}) \cdot (\overline{\mathrm{p}}_g \cdot {}^s\lambda_{3,g,i} - \underline{\mathrm{p}}_g \cdot {}^s\lambda_{4,g,i} + \Delta\mathrm{resu}_g \cdot {}^s\lambda_{5,g,i}) \cdot \frac{{}^s\tau}{\mathrm{w}} + \\
& \sum_{\substack{c=1..Nc \\ g=1..Ng \\ s=1..Ns}} ({}^s\gamma_g - {}^s\gamma_{g,i}) \cdot {}^s\lambda_{6,g,i}^c \cdot \underline{\mathrm{p}}_g \cdot \frac{{}^s\tau}{\mathrm{w}} + \\
& \sum_{\substack{c=1..Nc \\ g=1..Ng \\ s=1..Ns}} (-{}^s itrp_g^c + {}^s\mathrm{itrp}_{g,i}^c) \cdot ({}^s\lambda_{7,g,i}^c + {}^s\lambda_{8,g,i}^c) \cdot \overline{\mathrm{p}}_g \cdot \frac{{}^s\tau}{\mathrm{w}}
\end{aligned} \qquad \text{Eq. 4.32}$$

In Eq. 4.24-4.32, the subscript ‘s’ added to some variables and parameters refers to the operating condition. Infeasibility Benders cuts are not needed given that the O+X optimisation is never infeasible as demand can always be curtailed, this is supported by a number of secondary constraints added in the master subproblem that impedes infeasibilities (e.g. commit too many or few generating units, intertrip units that are not dispatched, etc.) and penalty factors in the slave objective functions over constraints violations (e.g. extra intertripping). Network enhancements can be defined as continuous (for fundamental studies) or integer variables (for more in-practice analyses). This formulation corresponds to a MILP problem.

4.3.3.1 Planning large networks

Binary variables γ_{g} and $itrp^{c}_{g}$ can be relaxed to be continuous in [0,1] in order to run planning studies over larger networks in reasonable timescales. Once obtained this relaxed solution, this is utilised to start a local search that looks for a good feasible solution to the non-relaxed optimisation. The heuristic stops when a given duality gap is ensured and works as follows:

1. Solve the relaxed version (with respect to γ_{g} and $itrp^{c}_{g}$) of the planning problem (note that γ_{g} and $itrp^{c}_{g}$ can be incorporated in the slave subproblems after this relaxation).
2. Define a unique trial list of network enhancements with: (i) the set of lines enhanced under the relaxation indicated in 1 and (ii) the set of lines with the largest weighted Lagrange multipliers (i.e. yearly shadow costs in $/MW) at the user's discretion.
3. Run the O+X optimisations with γ_{g} and $itrp^{c}_{g}$ as binary variables over all combinations of enhancements trials of the assets of the list defined in 2 and choose the combination with the minimum T+O+X duality gap. If the targeted duality gap is not satisfied, add more lines to the trial list.

Note that this algorithm only works when network enhancements take account of a limited set of potential network capacities (e.g. the ones commercially available).

4.3.4 The filtering module: finding the relevant or umbrella outage states

According to [67], the set of umbrella contingencies in a probabilistic assessment is a subset of the set of contingencies that is sufficient to attain levels of security and economic performance identical or nearly identical to those found when all contingencies are considered.

In this proposal, the set of umbrella outages is determined by undertaking a risk assessment (in terms of the expected post-fault cost by using the algorithm in Section 4.3.4.1) of each individual outage (contained in a comprehensive initial set) over a given intact system dispatch (i.e. set of pre-fault generation outputs and reserve allocation). This is carried out in several iterations as follows:

(i) define the set of umbrella outages as an empty set;

(ii) execute the operational module over the targeted operating condition when considering only the occurrences of the umbrella outages and obtain the optimum dispatch solution (in the first iteration, consider the occurrence of no outages to obtain the "N-0" optimum dispatch);

(iii) assess the risk associated with each individual event that is outside the set of umbrella outages (by using the algorithm in Section 4.3.4.1) over the intact system dispatch solution obtained in the previous step. The outage with the largest risk is identified and added to the set of umbrella outages;

(iv) sum the risks over all outages that are left outside the set of umbrella outages. If this sum is lower than a tolerance value predefined by the user (in $), stop. Otherwise, go to (ii).

The overall process mentioned above is illustrated in Figure 4.2.

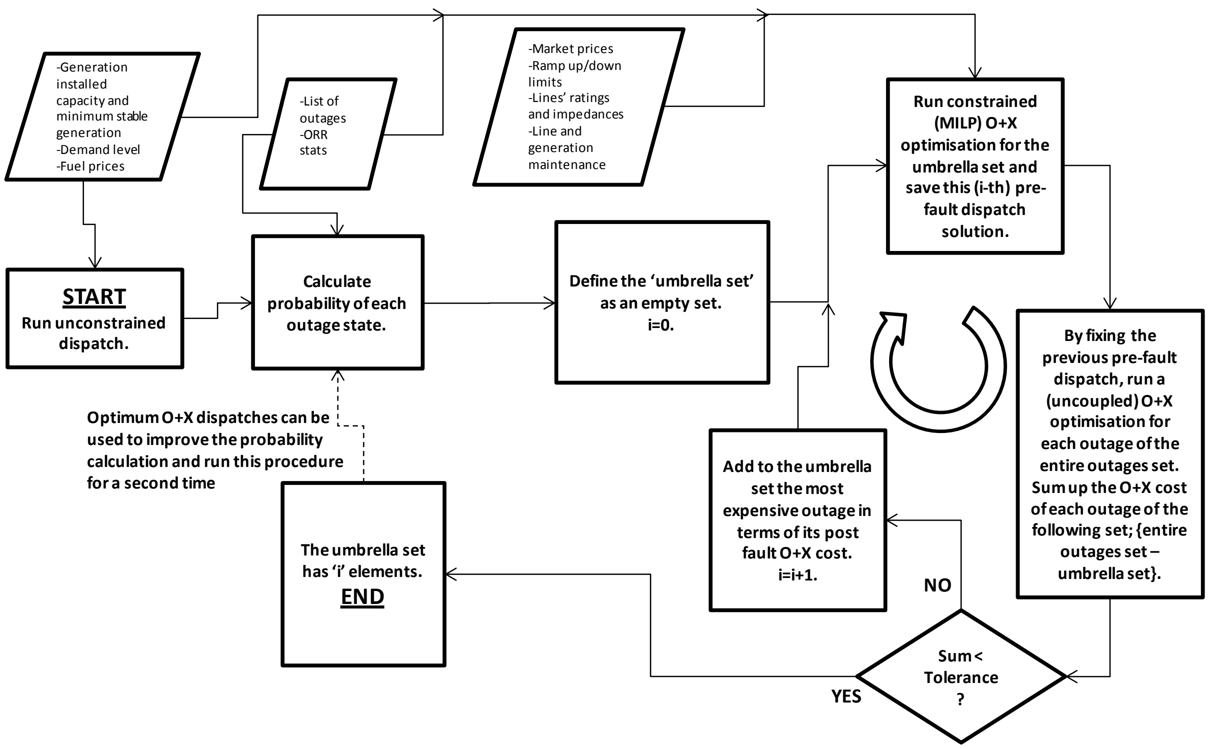

Figure 4.2: General flow chart of the filtering module's process

It can be observed from Figure 4.2 that by definition the outages left outside the set of umbrella outages will not cause severe risks for the system operation. What is more, it can be proven that the difference (or error incurred) in the overall O+X costs between the optimisation with all outages and the one with only the umbrella outages is lower than (or equal to) the given tolerance value. This proof is included in Appendix B.

The dotted line in Figure 4.2 indicates that this algorithm can be run twice in a row by using the final dispatch results to refine the probability calculation in a second execution[18]. Furthermore, the dispatch obtained after the Benders procedure is also used to update the probability calculation.

This set of relevant outages can be also utilised to rank the importance of each network component according to its contribution to system risk.

This algorithm given in the form of an outer approximation scheme can be contrasted with alternative approaches that incorporate scenario dropping schemes [68].

4.3.4.1 Risk assessment of a given intact system solution

The assessment of the expected post-fault cost of a given intact system dispatch is carried out by executing the probabilistic operational module (over the corresponding operating conditions and over a given set of operating states) with 2xNg extra constraints (where Ng is the number of generators) that force the intact system's output and reserve holding level of each generator to be equal to the those from the given intact system dispatch.

This process is computationally less costly than running an O+X optimisation where the intact system solution is not fixed. In effect, when the pre-fault dispatches are forced to be at a certain level, the optimisation of each operating state becomes independent from each other, alleviating the computational burden.

Risk assessment of a deterministic dispatch

It should be noted that this procedure can be applied over any set of (pre-fault) generation dispatches and even over one obtained by a deterministic N-1 SC-OPF, for example. In this case, this procedure will assess the risk associated to the given pre-fault deterministic dispatch by considering an optimum post-fault utilisation (that minimises the O+X cost) of the operational measures for all outages beyond N-1.

This assessment will tend to underestimate the risk value of the outages outside the set of credible events because, in reality, under a deterministic criterion the network is not necessarily designed to cope with this type of events.

[18] In the case of the examples explored, a third or fourth execution through the dotted line does not change significantly the dispatch solution and does not change the list of umbrella outages at all. This is aligned with the findings in [69] where the algorithm that determines the probability of each outage state is also run only twice.

4.3.5 Deterministic operation and planning formulations for benchmark

In order to demonstrate the characteristics of the probabilistic model above, results are benchmarked with those from a deterministic model.

The deterministic version of the proposed probabilistic model corresponds to an optimisation equal to the probabilistic one (in both operation and planning) but that considers: only N-1 outages; all state probabilities equal to 1; price of generation-based corrective actions approaching zero; and price of demand shedding approaching infinity. In other words, the deterministic version balances only the costs of transmission constraints and investment for a given reliability profile (i.e. N-1). This model corresponds to a SC-OPF with corrective control like the one proposed in [60].

As can be seen, corrective actions (that do not shed demand) are allowed within the deterministic approach above[19]. Comparisons of the probabilistic model with a merely preventive deterministic model are presented in Chapter 5.

4.4 Small-case study: validation and analysis over a 4-busbar example

The study in this section extends the fundamental analysis presented in Chapter 3 and scrutinises the proposed framework on a small-scale meshed network. This small-scale network serves to: (i) validate the model by means of a simple example and (ii) illustrate the benefits of the probabilistic approach through an understandable case. Here, the deterministic approach presented in Section 4.3.5 is used as a benchmark case. In the analysis, we focus on costs, risk/security, utilisation and enhancement of the transmission network and the usage of operational measures.

As a further validation, the model is compared with the results of another stochastic tool developed in [65] and published in IEEE. This comparison in presented in Appendix C.

4.4.1 Network description

The test system is composed of 4 nodes, 9 circuits, 4 generators, and 2 loads. Topology and other relevant data are given in Figure 4.3 and Table 4.1.

[19] Demand shedding is allowed for outages beyond the N-1 type and they are considered in the risk assessment.

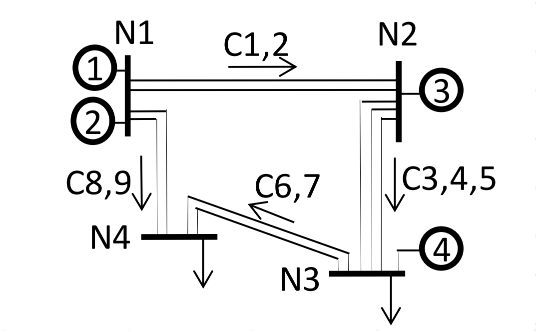

Figure 4.3: 4-busbar system topology (positive flow's directions defined by arrows)

Table 4.1: 4-busbar system's generation and network data

	Rating [MW]	λ [occ/yr]
C1	65	0.1
C2	65	0.1
C3	50	depend
C4	50	on
C5	50	weather
C6	15	0.1
C7	15	0.1
C8	90	0.1
C9	90	0.1

Generator	Capacity	Minimum generation	Ramp up/down	Fuel/bid/offer	Reserve up/down	λ
	MW			$/MWh		occ/yr
G1	200	50	150	10	10	18
G2	200	50	150	11	11	18
G3	200	100	100	20	20	18
G4	100	70	30	25	25	18

The transmission link composed of C3,4,5 has a higher failure rate (λ) which is also dependent on weather: 0.0011 and 0.0457 occ/h during a fair and an adverse weather hour, respectively. Additionally, VoLL and the utilisation price of SPS are assumed to be 30 k$/MWh and 200 k$ per unit tripped, respectively. For the sake of clarity, offer and bid prices are equalised to fuel prices as well as reserve up and down prices; the availability price of reserve has been neglected; and post-fault line ratings are equal to the pre-fault ones.

The model considers 92 operating states that represent all N-1 (13) and all N-2 (78) outages plus the intact system. The probability of each state is calculated assuming that all outage events are independent and exponentially distributed as expressed by Eq. 4.33.

$$\rho^c = \prod_{i \in U^c} (1 - \Pr_i) \prod_{j \in D^c} (\Pr_j) \qquad \text{where} \qquad \Pr_i = 1 - e^{-\lambda_i \times T} \approx \lambda_i \times T \qquad \text{Eq. 4.33}$$

$\Pr_i$ is the probability of finding network component i outaged over time T, and U^c and D^c are the sets of components out and in at operation condition c, respectively. More details about outage rates and probabilities can be found in Appendix A.

Finally, a year with 2 operating conditions is considered for planning studies: a peak (100 MW in each node 3 and 4) and off-peak demand (60 MW in each node 3 and 4).

4.4.2 Optimum network utilisation, its costs and risks

The dispatch solution to this example during the peak demand condition without considering any network or risk constraints (i.e. unconstrained dispatch) is evidently to fully dispatch the cheapest unit G1. However, this dispatch solution is exposed to demand curtailment (and other post-fault actions) under the occurrence of several outage events, including the single failures of G1, C8 and C9. While under an N-1 deterministic perspective this will be unacceptable, a probabilistic approach could agree to this solution if the cost to increase the levels of security by balancing the system in the pre-fault condition is higher than the benefit obtained by the corresponding decrease in risk. However in this case, deterministic and probabilistic methods do balance the system and their solutions are presented in Table 4.2.

Table 4.2: Generation outputs and network utilisations (a. left) and cost and risks (b. right) of the deterministic and probabilistic solutions

		Probabilistic		Deterministic
		Fair weather	Adverse weather	All weather
Generation [MW]	G1	150	80	50
	G2	50	50	50
	G3	0	0	100
	G4	0	70	0
Transfers [MW]	C1+C2	82	44	9
	C3+C4+C5	82	44	109
	C6+C7	-18	14	9
	C8+C9	118	86	91

		Cost of [$/30mins]				
		Constraints	Reserve utilization	SPS	DR	Total O+X
Probabilistic	Fair weather	27.5	1.1	2.6E-05	6.1	35
	Adverse weather	556.0	1.1	2.3E-05	2.2	559
Deterministic	Fair weather	532.5	1.1	0.2	0.6	534
	Adverse weather	532.5	1.6	284.4	533.3	1352

There are two probabilistic solutions since risks of network failures are different in fair and adverse weather. The shown deterministic solution is obtained by considering N-1 events only, constraining the use of DR, and permitting the use of further corrective control measures at no cost (see formulation in Section 4.3.5).

In Table 4.2b, the risks under fair and adverse weather of the deterministic dispatch are measured by the probabilistic process described in Section 4.3.4.1 and when considering all N-1 and N-2 outages. For the N-2 outages, an optimum post-fault utilisation of operational measures is considered given the pre-fault deterministic dispatch as an initial condition. This will tend to underestimate the risk value of the outages outside the set of credible events in the deterministic dispatch because, in reality, the network is not necessarily designed to cope with these types of events. In Table 4.3, major outages (that drive higher risks) are presented.

Table 4.3: Post-fault costs (upper) and actions (lower) of risky operating states

Expected cost of [$/30mins]								
	Fair weather				Adverse weather			
	Probabilistic		Deterministic		Probabilistic		Deterministic	
Outage	SPS	DR	SPS	DR	SPS	DR	SPS	DR
C1	0.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0
C2	0.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0
C8	0.0	0.4	0.0	0.0	0.0	0.4	0.0	0.0
C9	0.0	0.4	0.0	0.0	0.0	0.4	0.0	0.0
G1+G2	0.0	3.2	0.0	0.2	0.0	1.5	0.0	0.2
C3+C4	0.0	0.1	0.1	0.1	0.0	0.0	94.8	177.7
C3+C5	0.0	0.1	0.1	0.1	0.0	0.0	94.8	177.7
C4+C5	0.0	0.1	0.1	0.1	0.0	0.0	94.8	177.7

Corrective actions (DR in [MW]node3-[MW]node4 and SPS in unit tripped)								
	Fair weather				Adverse weather			
	Probabilistic		Deterministic		Probabilistic		Deterministic	
Outage	SPS	DR	SPS	DR	SPS	DR	SPS	DR
C1	-	10-0	-	0-0	-	0-0	-	0-0
C2	-	10-0	-	0-0	-	0-0	-	0-0
C8	-	0-5	-	0-0	-	0-5	-	0-0
C9	-	0-5	-	0-0	-	0-5	-	0-0
G1+G2	-	100-100	-	0-12	-	0-100	-	0-12
C3+C4	-	25-0	G3	25-0	-	0-0	G3	25-0
C3+C5	-	25-0	G3	25-0	-	0-0	G3	25-0
C4+C5	-	25-0	G3	25-0	-	0-0	G3	25-0

An interesting characteristic of the probabilistic solution is that during both fair and adverse weather there is exposure to demand being shed under N-1-type outages (see Table 4.3). This exposure is minimised to zero by the deterministic solution and no re-dispatch actions are needed under any network single outage (though the use of SPS is permitted).

Despite this, the deterministic dispatch is still exposed to higher levels of risk during adverse weather due to the significant post-fault cost expected under double network outages driven by corrective actions of both generation and demand (see Table 4.2b and Table 4.3). Additionally, although the deterministic solution does decrease the risk under fair weather, it is a more expensive solution during pre-fault, as it is inefficient with respect to the total cost (see Table 4.2b). These problems can be explained because of two major disadvantages of the deterministic framework:

1. It does not explicitly assess the consequential cost of any outage (including the utilisation of the corrective actions) which can be significantly different depending on system conditions (e.g. depending on weather);
2. It arranges the usage of corrective actions in a way that can be highly inefficient (for example, limitations of using Demand Response (DR) under credible events and permission to use SPS without any post-fault cost consideration).

In this case, for instance, the deterministic method cannot perceive that C3,4,5 is less reliable and that this lack of reliability can become potentially critical for the proper use of corrective control under certain condition (for instance, adverse weather). Thus, while the deterministic method increases the transfers through C3,4,5 in order to lower and so withstand an N-1 outage in C8,9 without DR, the probabilistic solution does exactly the opposite: deploy alternative operational measures in order to cope with an outage in C8,9 (through corrective control) and minimise the load in C3,4,5 given that the latter is highly unreliable.

As we can observe in this example, the use of operational measures in the deterministic framework is not only limited (to N-2 line outages and beyond) but also is carried out in a costly manner.

4.4.3 Optimum network enhancements

For planning timescales, a year is studied which is composed of 4 conditions: peak and off- peak demand combined with fair and adverse weather. The time duration of the peak and fair weather (t1), off-peak and fair weather (t2), peak and adverse weather (t3); and off-peak and adverse weather (t4) condition are 394, 7490, 44 and 832 hours, respectively. The probabilistic and deterministic planning solution for an investment costs of 3500 $/MW/yr is shown in Table 4.4 where link C6,7 is enhanced by 5.7 MW and link C8,9 is also enhanced by 5.7 MW by the deterministic method.

Table 4.4: Total investment and operational costs under deterministic and probabilistic criteria at a unit investment cost of 3500 $/MW/yr

	Cost of [10^3 $/yr]					
	T	O + X				T+O+X
	Investment	Constraints	Reserve utilization	SPS	DR	Total
Deterministic	40	482	12	0	81	615
Probabilistic	0	528	12	0	36	576

The first point to notice is that the deterministic planning does not necessarily solve the problem of high risk exposure (under certain conditions) because, as studied earlier, this risk can be driven by events that are beyond the set of secured outages considered.

Second, we can observe that under the probabilistic approach no investment is needed and, in fact, the set of operational measures deployed (some of those explained in the previous section) is enough to achieve both lower levels of overall costs and risks.

Additionally, a sensitivity analysis in the cost of investment (dropped to 700 $/MW/yr) shows that while enhancements are undertaken in links C6,7 and C8,9 under the deterministic solution (5.7 MW of extra capacity in each link), under the probabilistic framework enhancements are preferable in links C3,4,5 (30 MW of extra capacity) and C6,7 (10 MW of extra capacity). This is coherent with the utilisation levels observed in operational timescales under each framework and proves that a deterministic framework for security will not only under/overinvest in transmission but also invest in the wrong set of assets.

4.4.4 Algorithm performance: umbrella states and simplifications

The umbrella states of the peak demand condition during fair and adverse weather are obtained by using the proposed algorithm in Section 4.3.4. Only 11 and 10 outages during fair and adverse weather, respectively are classified as umbrella. Table 4.5 shows the results of the filtering module per iteration.

Table 4.5: Umbrella states per iteration for fair (upper) and adverse (lower) weather in the peak demand condition.

Iteration	1	2	3	4	5	6	7	8	9	10	11	Risk of remaining outages [$/30mins]
Outage fair weather	G1	G2	G1 + G2	C1	C2	C8	C9	C3 + C4	C3 + C5	C4 + C5	G1 + C1	0.02
Outage adverse weather	G1	G2	C3 + C4	C3 + C5	C4 + C5	G1 + G2	G1 + G4	G2 + G4	G4	G1 + C3	/	0.07

The lists of 11 and 10 umbrella contingencies for fair and adverse weather, respectively, drive the same operational solution as the initial 91-outage set, being the sum of risks of the outages that are outside these umbrella sets (i.e. O+X error) less than 0.02 and 0.07 $/30min for fair and adverse weather, respectively.

Expectedly, all single and double generation outages are included since, in this example, generation has significantly higher probabilities of failure (i.e. not to consider these outages can lead to an underestimation of the O+X cost). Also, all double outages involving the link C3,4,5 are included. Single events in the aforementioned link are not included as they drive neither preventive nor corrective actions (this is aligned with our analysis in Section 4.4.2).

Despite the small sizes of these umbrella sets, it can be proved that the number of umbrella outages can be reduced even further in operational timescales[20]. However, this will jeopardise the quality of the solution in planning timescales.

The outages in Table 4.5 also drive the optimum solution in planning timescales by carrying out only one iteration of loop 1 (see algorithm in Figure 4.1). The convergence of the Benders process with the entire set and the umbrella set is shown in Figure 4.4.

[20] Indeed, to obtain the optimum dispatch solution during fair weather, it is only necessary to consider the single outage of G1 (i.e. first member of the list of the umbrella outages). Likewise, to obtain the optimum dispatch solution during adverse weather, it is only necessary to consider the single outages of G1 and G2, and all the double outages of the link C3,4&5 (i.e. first 5 members of the list of umbrella outages). The final solutions driven by these shortened lists are still optimum albeit the values of the O+X objective function (during fair and adverse weather) are significantly reduced (i.e. outages with a total risk of 5 £/30min are ignored in both cases).

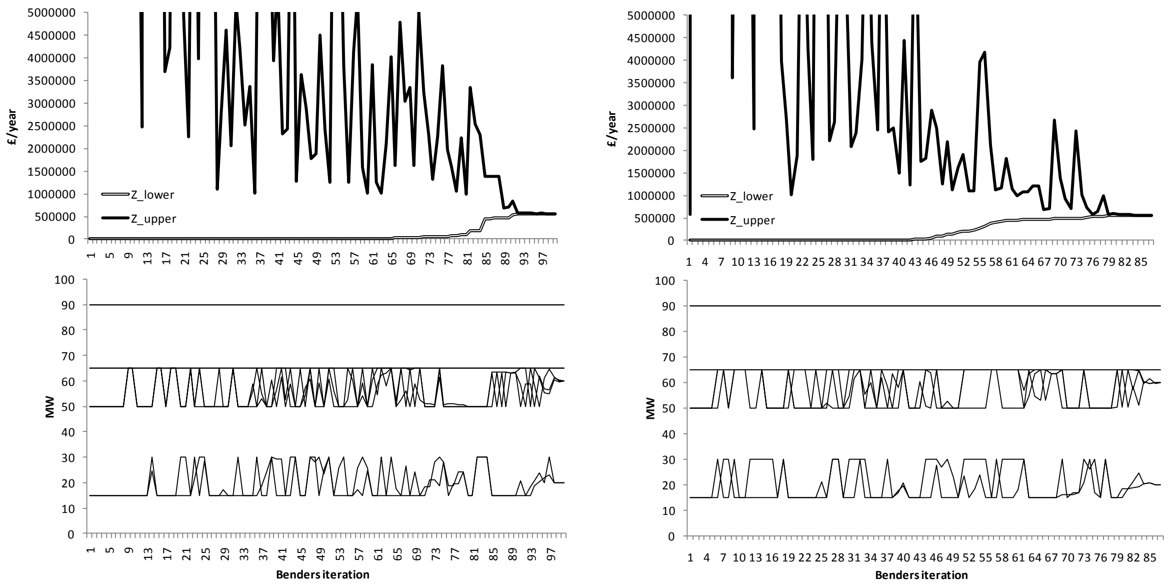

Figure 4.4: Benders convergence with the entire set of outages (left) and the umbrella set (right) at an investment cost of 700 \$/MW/yr

The T+O+X optimisation takes about 30 seconds and 100 Benders iteration with the entire set of outages. These numbers are reduced to only 22 seconds and 87 Benders iteration when considering the umbrella set.

Finally, if the planning problem is relaxed and thereby simplified and a LP optimisation executed as indicated in Section 4.3.3.1, no network enhancements are undertaken. Nevertheless, the summations of the Lagrange multipliers of the lines' capacity constraints over a year are demonstrated to be a good indicator to start a local search. In effect, the candidate lines to be enhanced in this case will be: C6,7, C3,4,5 and C8,9 (in that order). The annual summations of the Lagrange multipliers are shown in Table 4.6.

Table 4.6: Weighted summation of the Lagrange multipliers at an investment cost of 700 \$/MW/yr

Circuit	Annual Lagrange multiplier of the lower flow constraints $\left\lvert \sum_{\substack{c \text{ in umbrella} \\ s=1..4}} {}^{s}\lambda_{1,l}^{c} \cdot \frac{{}^{s}\tau}{\mathrm{w}} \right\rvert$ [\$/yr]	Annual Lagrange multiplier of the upper flow constraints $\left\lvert \sum_{\substack{c \text{ in umbrella} \\ s=1..4}} {}^{s}\lambda_{2,l}^{c} \cdot \frac{{}^{s}\tau}{\mathrm{w}} \right\rvert$ [\$/yr]
1	0	0
2	0	0
3	0	216
4	0	216
5	0	216
6	470	0
7	470	0
8	118	0
9	118	0

Since the final solution is a subset of the set of candidate lines to be enhanced, this exercise illustrates and validates the heuristic procedure proposed in Section 4.3.3.1 to optimise large-scale networks in which the MILP cannot be solved. A further validation is shown in Section 4.5.3, where the aforementioned algorithm is applied to obtain a 2 % duality gap on a 24-busbar system.

Although the savings in time and computational effort are not critical in this small-scale network, the exercise above demonstrates that the proposed filtering module and further simplifications are capable of delivering an optimum solution. This is promising in the study of large-scale networks.

4.5 IEEE RTS Study

In this section the proposed probabilistic framework on the 24-busbar IEEE RTS is applied. Focus is given to enhancements driven by the probabilistic and deterministic criteria as well as on the probabilistic algorithm's computational performance.

4.5.1 Network description

The IEEE RTS contains 32 generators and 38 lines as explained in [70]. The main set of data of generation (e.g. installed capacities, ramp rates, failure rates, technologies, etc) and transmission assets (e.g. admittances, length, failure rates, ratings, etc) loaded in the model can be found in Table 4.7 and Table 4.8.

Table 4.7: Generation parameters

ID	Unit	Technology	Node	Capacity [MW]	Minimum generation [MW]	Ramp Up/Dw [MW]	Fuel Price [£/MWh]	Bid Price [£/MWh]	Offer Price [£/MWh]	0.5 x λ [p.u.]
1	U20	Oil	1	20	8	12	120.1	114.4	126.1	0.00111
2	U20	Oil	1	20	8	12	120.2	114.5	126.2	0.00111
3	U76	Coal	1	76	30	20	50.3	47.9	52.8	0.000255
4	U76	Coal	1	76	30	20	50.4	48.0	52.9	0.000255
5	U20	Oil	2	20	8	12	120.5	114.8	126.5	0.00111
6	U20	Oil	2	20	8	12	120.6	114.9	126.6	0.00111
7	U76	Coal	2	76	30	20	50.7	48.3	53.2	0.000255
8	U76	Coal	2	76	30	20	50.8	48.4	53.3	0.000255
9	U100	Oil	7	100	40	60	120.9	115.1	126.9	0.000417
10	U100	Oil	7	100	40	60	121	115.2	127.1	0.000417
11	U100	Oil	7	100	40	60	121.1	115.3	127.2	0.000417
12	U197	Oil	13	197	79	30	121.2	115.4	127.3	0.000526
13	U197	Oil	13	197	79	30	121.3	115.5	127.4	0.000526
14	U197	Oil	13	197	79	30	121.4	115.6	127.5	0.000526
15	U12	Oil	15	12	5	7	121.5	115.7	127.6	0.00017
16	U12	Oil	15	12	5	7	121.6	115.8	127.7	0.00017
17	U12	Oil	15	12	5	7	121.7	115.9	127.8	0.00017
18	U12	Oil	15	12	5	7	121.8	116.0	127.9	0.00017
19	U12	Oil	15	12	5	7	121.9	116.1	128.0	0.00017
20	U155	Coal	15	155	62	30	52	49.5	54.6	0.000521
21	U155	Coal	16	155	62	30	52.1	49.6	54.7	0.000521
22	U400	Nuclear	18	400	360	40	7.2	6.9	7.6	0.000454
23	U400	Nuclear	21	400	360	40	7.3	7.0	7.7	0.000454
24	U50	Hydro	22	50	5	45	7.4	7.0	7.8	0.000252
25	U50	Hydro	22	50	5	45	7.5	7.1	7.9	0.000252
26	U50	Hydro	22	50	5	45	7.6	7.2	8.0	0.000252
27	U50	Hydro	22	50	5	45	7.7	7.3	8.1	0.000252
28	U50	Hydro	22	50	5	45	7.8	7.4	8.2	0.000252
29	U50	Hydro	22	50	5	45	7.9	7.5	8.3	0.000252
30	U155	Coal	23	155	62	30	53	50.5	55.7	0.000521
31	U155	Coal	23	155	62	30	53.1	50.6	55.8	0.000521
32	U350	Coal	23	350	140	40	53.2	50.7	55.9	0.000435

In Table 4.7 generation capacities and reliability parameters were obtained directly from [70]. Minimum stable generation limits were estimated by using a factor of 40% for conventional units, 90% for nuclear units and a minimum of 5 MW for hydro units. Ramp limits were obtained also from [70] by using a time length of 10 minutes. In here, ramp limits were decreased for some generating units in order to equalise them to the difference between their maximum and minimum feasible outputs. Fuel prices were set to have a reasonable merit order; and the offer and bid prices based on a +-5% factor over the associated fuel prices. A small differential of 0.1 times the generator's ID number (in $/MWh) is added to the fuel price so as to have a unique (unconstrained) generation dispatch solution.

Table 4.8: Network parameters

ID	From node	To node	X [p.u.]	Prefault rating [MW]	Lenght [km]	Cost [£/MW/year]	0.5 x λ fair weather [p.u.]	0.5 x λ adverse weather [p.u.]
1	1	2	0.014	175	5	290	1.4E-05	4.4E-04
2	1	3	0.211	175	89	5311	1.9E-04	6.2E-03
3	1	5	0.085	175	35	2124	8.7E-05	2.8E-03
4	2	4	0.127	175	53	3187	1.2E-04	3.8E-03
5	2	6	0.192	175	80	4828	1.8E-04	5.6E-03
6	3	9	0.119	175	50	2993	1.1E-04	3.6E-03
7	3	24	0.084	400	0	20000	1.1E-06	3.7E-05
8	4	9	0.104	175	43	2607	1.0E-04	3.2E-03
9	5	10	0.088	175	37	2221	8.8E-05	2.8E-03
10	6	10	0.061	175	26	1545	1.9E-05	6.0E-04
11	7	8	0.061	175	26	1545	6.3E-05	2.0E-03
12	8	9	0.165	175	69	4152	1.6E-04	5.0E-03
13	8	10	0.165	175	69	4152	1.6E-04	5.0E-03
14	9	11	0.084	400	0	20000	1.1E-06	3.7E-05
15	9	12	0.084	400	0	20000	1.1E-06	3.7E-05
16	10	11	0.084	400	0	20000	1.1E-06	3.7E-05
17	10	12	0.084	400	0	20000	1.1E-06	3.7E-05
18	11	13	0.048	500	53	3187	6.8E-05	2.2E-03
19	11	14	0.042	500	47	2800	6.2E-05	2.0E-03
20	12	13	0.048	500	53	3187	6.8E-05	2.2E-03
21	12	23	0.097	500	108	6470	1.2E-04	3.9E-03
22	13	23	0.087	500	97	5794	1.1E-04	3.6E-03
23	14	16	0.059	500	43	2607	6.2E-05	2.0E-03
24	15	16	0.017	500	19	1159	3.6E-05	1.2E-03
25	15	21	0.049	500	55	3283	6.9E-05	2.2E-03
26	15	21	0.049	500	55	3283	6.9E-05	2.2E-03
27	15	24	0.052	500	58	3476	7.5E-05	2.4E-03
28	16	17	0.026	500	29	1738	4.3E-05	1.4E-03
29	16	19	0.023	500	26	1545	4.2E-05	1.4E-03
30	17	18	0.014	500	16	966	3.0E-05	9.5E-04
31	17	22	0.105	500	117	7049	1.3E-04	4.3E-03
32	18	21	0.026	500	29	1738	4.3E-05	1.4E-03
33	18	21	0.026	500	29	1738	4.3E-05	1.4E-03
34	19	20	0.04	500	44	2655	6.2E-05	2.0E-03
35	19	20	0.04	500	44	2655	6.2E-05	2.0E-03
36	20	23	0.022	500	24	1448	4.2E-05	1.4E-03
37	20	23	0.022	500	24	1448	4.2E-05	1.4E-03
38	21	22	0.068	500	76	4538	9.4E-05	3.0E-03

All network parameters are obtained from [70] besides the investment costs and the probabilities of single circuit outages in adverse weather. The former are calculated based on a unitary cost of 60 $/MW/km/yr and the latter are obtained by using a factor of 32 times over probabilities of having single circuit outages during fair weather (which were also obtained from [70]).

With respect to the operating conditions, a year is divided into summer and winter by using 2 typical days with 5 load levels each. Summer was considered with fair weather only whilst winter is considered with adverse and fair weather (adverse weather corresponds to 12% of the winter period). To take account of the combination of the different demand levels with the weather conditions, it was necessary to model at least 15 operating conditions.

In order to minimise the increase in the aforementioned number of operating conditions (when also considering generation and line maintenance) and the N-2 line states, the planning problem is centred on one main transmission corridor or boundary formed by the high voltage side of all substations (i.e. all transformers and lines 18, 19, 20, 21 and 27) that divide the system into 2 areas: high and low voltage (see Figure 4.5). The set of forced outages considers all N-1 events of generation and transmission plus a set of selected N-2 line events that affects the targeted boundary (109 operating states considering intact system). Generation and line maintenance are planned in order not to undervalue transmission investment on the boundary; therefore all generating units in the low voltage area (i.e importing area) are maintained (1 month each) along with all circuits of the boundary (2 weeks each). These considerations ultimately drive 40 operating conditions which are defined in Table 4.9. A diagram of the RTS is depicted in Figure 4.5.

Table 4.9: Operating conditions

Operating condition	Duration [hrs]	Demand [p.u.]	Weather	Season	Maintenance
1	1206	0.5632	fair	winter	Intact system
2	241	0.6688	fair	winter	Intact system
3	1972	0.7568	fair	winter	Intact system
4	33	1.0000	fair	winter	Intact system
5	402	0.7040	fair	winter	Intact system
6	164	0.5632	adverse	winter	Intact system
7	33	0.6688	adverse	winter	Intact system
8	269	0.7568	adverse	winter	Intact system
9	4	1.0000	adverse	winter	Intact system
10	55	0.7040	adverse	winter	Intact system
11	852	0.4469	fair	summer	Generation maintenance
12	122	0.5687	fair	summer	Generation maintenance
13	1277	0.6684	fair	summer	Generation maintenance
14	304	0.6314	fair	summer	Generation maintenance
15	365	0.5806	fair	summer	Generation maintenance
16	85	0.4469	fair	summer	Line maintenance (L27)
17	12	0.5687	fair	summer	Line maintenance (L27)
18	128	0.6684	fair	summer	Line maintenance (L27)
19	30	0.6314	fair	summer	Line maintenance (L27)
20	37	0.5806	fair	summer	Line maintenance (L27)
21	85	0.4469	fair	summer	Line maintenance (L18)
22	12	0.5687	fair	summer	Line maintenance (L18)
23	128	0.6684	fair	summer	Line maintenance (L18)
24	30	0.6314	fair	summer	Line maintenance (L18)
25	37	0.5806	fair	summer	Line maintenance (L18)
26	85	0.4469	fair	summer	Line maintenance (L19)
27	12	0.5687	fair	summer	Line maintenance (L19)
28	128	0.6684	fair	summer	Line maintenance (L19)
29	30	0.6314	fair	summer	Line maintenance (L19)
30	37	0.5806	fair	summer	Line maintenance (L19)
31	85	0.4469	fair	summer	Line maintenance (L20)
32	12	0.5687	fair	summer	Line maintenance (L20)
33	128	0.6684	fair	summer	Line maintenance (L20)
34	30	0.6314	fair	summer	Line maintenance (L20)
35	37	0.5806	fair	summer	Line maintenance (L20)
36	85	0.4469	fair	summer	Line maintenance (L21)
37	12	0.5687	fair	summer	Line maintenance (L21)
38	128	0.6684	fair	summer	Line maintenance (L21)
39	30	0.6314	fair	summer	Line maintenance (L21)
40	37	0.5806	fair	summer	Line maintenance (L21)

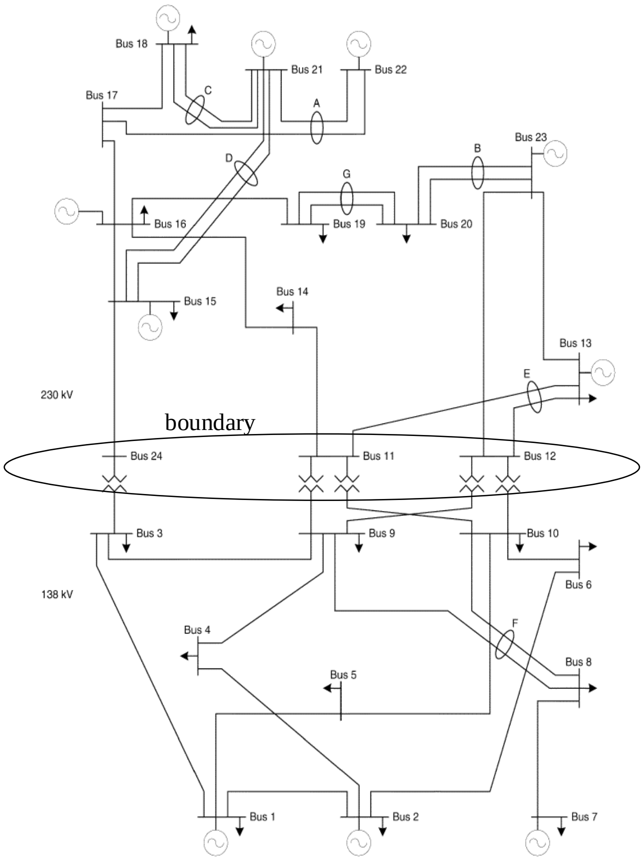

Figure 4.5: IEEE RTS configuration and boundary definition

The demand distribution per node is presented in Table 4.10 at peak load.

Table 4.10: Peak demand per node

Node	1	2	3	4	5	6	7	8	9	10	13	14	15	16	18	19	20	Total
Demand [MW]	108	97	180	74	71	136	125	171	175	195	265	194	317	100	333	181	128	2850

Finally, the VoLL is equalised to 1 k$/MWh, the SPS utilisation price to 7 k$ per unit tripped and the reserve availability price to 15 $/MW/h. Furthermore, the post-fault line ratings are considered to be 25% higher than the pre-fault ones.

4.5.2 Case study description

The IEEE RTS is already a system that does not require investment in its original configuration. In this context, the connection of 3 new participants was analysed: 1 GW of new peak demand in node 9 (importing area –low voltage–) and 500 MW of new nuclear generation in node 16 and 500 MW of new nuclear generation in node 23 (both in the exporting area –high voltage–). The aim is to obtain the new enhancements required on the boundary, and study the use of operational measures and costs and risks over the new system under the deterministic and probabilistic methods.

4.5.3 Results

As expected, Table 4.11 shows that the total annual cost under the probabilistic method is lower than under the deterministic one which is more costly in terms of the investment, constraints and reserves costs. Expected utilisation of SPS over generation and demand are less expensive but inefficient, as the benefit of minimising their usage does not compensate the extra costs in provisioning security through transmission investment and constraints. Furthermore, the extra enhancements carried out in the deterministic scenario on the substations present lower levels of utilisation in the intact system, defining higher levels of asset redundancy (see Table 4.11 and Table 4.12).

Table 4.11: Annual T+O+X costs under the N-1 deterministic and probabilistic criteria

	Cost of [k$/yr]						
	T	O				X	T+O+X
	Investment	Constraints	Reserve holding	Reserve utilization	SPS	DR	
Deterministic	17255	82052	52132	250	1	3	151693
Probabilistic	11680	62192	47339	208	2	352	121773

Table 4.12: Capacity and pre-fault annual utilisation levels at the boundary

		Deterministic		Probabilistic	
		Δcapacity [MW]	Average utilization [%]	Δcapacity [MW]	Average utilization [%]
Substation	T7	0	88%	100	72%
	T14	200	51%	100	62%
	T15	200	50%	100	62%
	T16	200	29%	100	36%
	T17	200	28%	100	36%
Line	L18	0	19%	0	21%
	L19	100	64%	100	64%
	L20	0	21%	0	22%
	L21	0	73%	0	76%
	L27	0	71%	0	72%

The extra capacity needed in the substation (T14,15,16,17) under the deterministic approach is so to withstand the single outage of a transformer. Nevertheless, as transformers have a lower failure rate, the probabilistic method prefers to deploy operational measures with the benefit of a saving in investment cost.

The resultant constraints costs were higher in the deterministic case due to the higher redundancy levels in the boundary's lines and the limited participation of DR.

4.5.4 Algorithm performance of the probabilistic method

FICO Xpress v7.1 [71] installed on a computer with two 6-core processors (Intel Xeon X5680) and 192 GB of RAM was used.

In operational timescales, the analysis of one operating condition takes about 9 seconds on average when considering the 109 operating states. This time can be reduced to about 1.5 seconds when considering only the umbrella states as shown in Figure 4.6. The filtering module takes about 400 seconds for all operating conditions by executing 12 snapshots at the time (in parallel) in order to derive the umbrella outages.

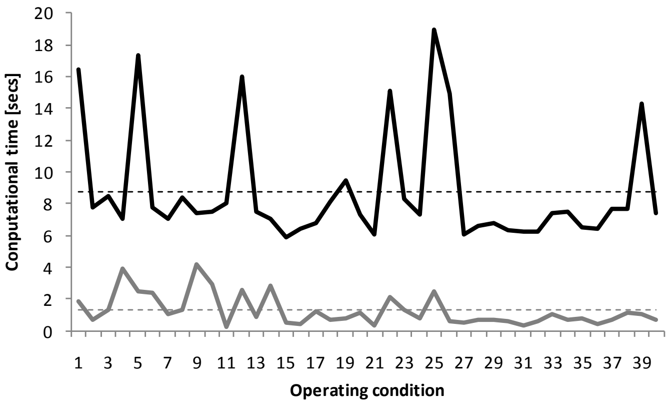

Figure 4.6: Computational times when considering all operating states (upper line) and the umbrella states (lower line) per operating condition

The number of operating states that drive the optimum decision in operation is considerably lower than the ones initially considered. In fact, less than 30 outages are needed in the optimisation of most of the operating condition. Only during the peak demand period the number of umbrella outages increases to circa 60 and 70 events (during fair and adverse weather in winter, respectively). This is shown in Figure 4.7.

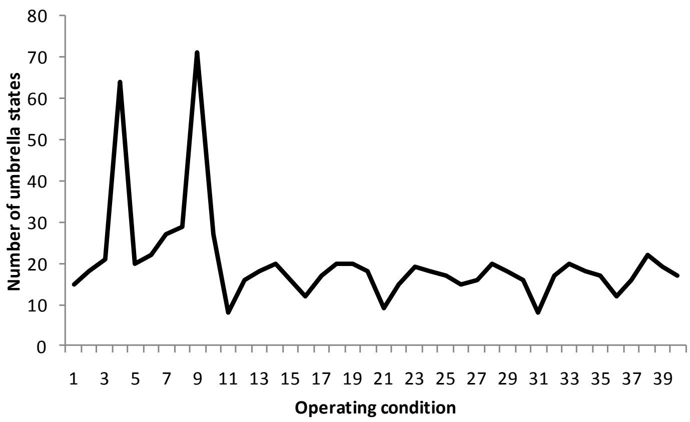

Figure 4.7: Number of umbrella states per operating condition

In planning timescales, the time improvements achieved by deriving the umbrella states is complemented by the employment of parallel processing tools which serve to run the O+X optimisation of an array of operating conditions at the same time. According to the number of parallel processes run, times can be reduced by up to a factor of 4 as shown in Figure 4.8. This figure depicts the time of the Benders process of the relaxed optimisation (according to Section 4.3.3.1) for both the T+O+X optimisation with all operating states and with only the umbrella outages.

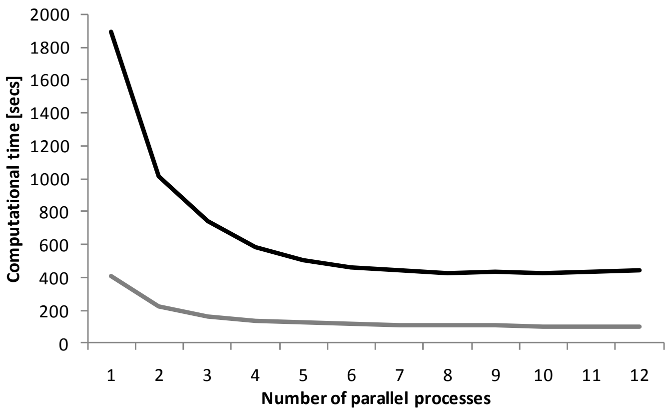

Figure 4.8: T+O+X computational times when considering all operating states (upper line) and the umbrella states (lower line) according to the number of parallel processes run

The duration of a planning study varies significantly (from minutes to hours) depending on the size of the local search explained in Section 4.3.3.1. In this example, (i) one LP Benders process took about 100 seconds in average by executing 12 snapshots at the time in parallel (see Figure 4.8), and (ii) the following heuristic took about 1.5 hours in average to undertake a local search which obtained an integer solution with a 2% duality gap (i.e 729 (3^6) transmission enhancement trials were run that took account of all combination of investments in lines T7, T14, T15, T16, T17, L19 with 3 possible levels +500, +1000 and +1500 MW). (i) and (ii) were run 3 times, i.e. loop 1 was iterated twice (see Figure 4.1). Hence, the entire planning study lasted about 5 hours.

4.6 Conclusions

This chapter derives the full mathematical formulation and analyses various characteristics of a fully integrated economic and reliability probabilistic approach for network operation and expansion. The formulation is translated into a computational optimisation model that is capable of being executed on reasonably large meshed networks in reduced times.

The model balances the need for transmission enhancements with the deployment of an array of operational measures such as pre-fault balancing actions, reserve commitments, post-fault demand and generation shedding through SPS, and generation re-dispatching. Through this model, it is shown that the associate probabilistic framework proposed delivers network security by using an efficient mix of network redundancy and operational measures.

Finally, this chapter highlights the fact that the deterministic framework is not necessarily more secure and, in effect, this can drive major risks in system network operation and incorrect network designs. These problems can be corrected by using a probabilistic approach for network security.

CHAPTER 5: Applying probabilistic network security standards on the GB system

Abstract

This chapter quantifies the impacts of applying the proposed probabilistic framework on a 29-busbar equivalent network of the GB transmission system. In the analysis, the benefits of the probabilistic approach in terms of both the savings in operational and in investment costs are highlighted even when considering the increase in the costs of losses and expected unsupplied demand caused by the increased network utilisation. Apart from the economic benefits, this chapter also demonstrates that the current standards might become a barrier for renewables in the future, leading to the curtailment of significant amount of wind power by 2020, in spite of higher amounts of investment in network assets. In contrast, the proposed probabilistic framework can integrate the same amount of wind capacity but with lower levels of wind curtailment and transmission investment.

5.1 Introduction

This chapter applies the probabilistic framework proposed in Chapter 3 and the model described in Chapter 4 on a 29-busbar equivalent network of the GB transmission system. For the comparisons, the probabilistic results are contrasted with those obtained by using a deterministic model similar to that utilised in Chapter 4. One important difference for results presented in this chapter is that the use of corrective control under the deterministic approach is not permitted.

The current N-2 deterministic rule that serves to determine the levels of network redundancy in GB does not take account of the support from corrective control when a network outage occurs [72]. This means that the Main Interconnected Transmission System (MITS) must be able to withstand a loss of one or two circuits without causing overloads of any other circuit (i.e. without threatening the integrity of system operation) and without the utilisation of any generation, demand or network based post-fault actions. Therefore, for example, if it is assumed that each of the four circuits in the England-Scotland interconnector has a capacity of 1.4 GW[21], the overall transfer through this boundary under this deterministic policy will be limited to 2.8 GW.

To obtain such a solution in modelling terms, a Security Constrained Optimum Power Flow (SC-OPF) like that proposed in [59] is computed in a preventive mode, i.e. congestion is the only control variable to cope with the prescribed set of outages (more details of this formulation can be seen in Appendix D). Risk measurements of a deterministic solution are carried out based on the probabilistic modelling indicated in Section 4.3.4.1. The risk measurement considers the occurrence of events beyond the set of credible outages and does not consider generation re-dispatch actions after a line outage occurs.

In light of the necessity for future transmission assets to connect and transport renewable energy from Scotland to England, the assessment of the economic feasibility is focussed on:

(i) delivering extra transmission capacity through the current transmission assets by deploying operational measures from the generation and demand side;

(ii) reducing the amount of future transmission assets needed.

[21] Post-fault line rating

5.2 Description of the GB system and modelling scenarios

5.2.1 Operational timescale

The equivalent 29-busbar GB transmission network recently developed by [73] is assessed along with future wind, conventional generation and demand backgrounds. The general topology of this network is depicted in Figure 5.1 where demand, generation, voltage levels and the Cheviot boundary (that splits the system into 2 parts through the England-Scotland interconnector) are clearly indicated. Nodes' names are also shown in Table 5.1.

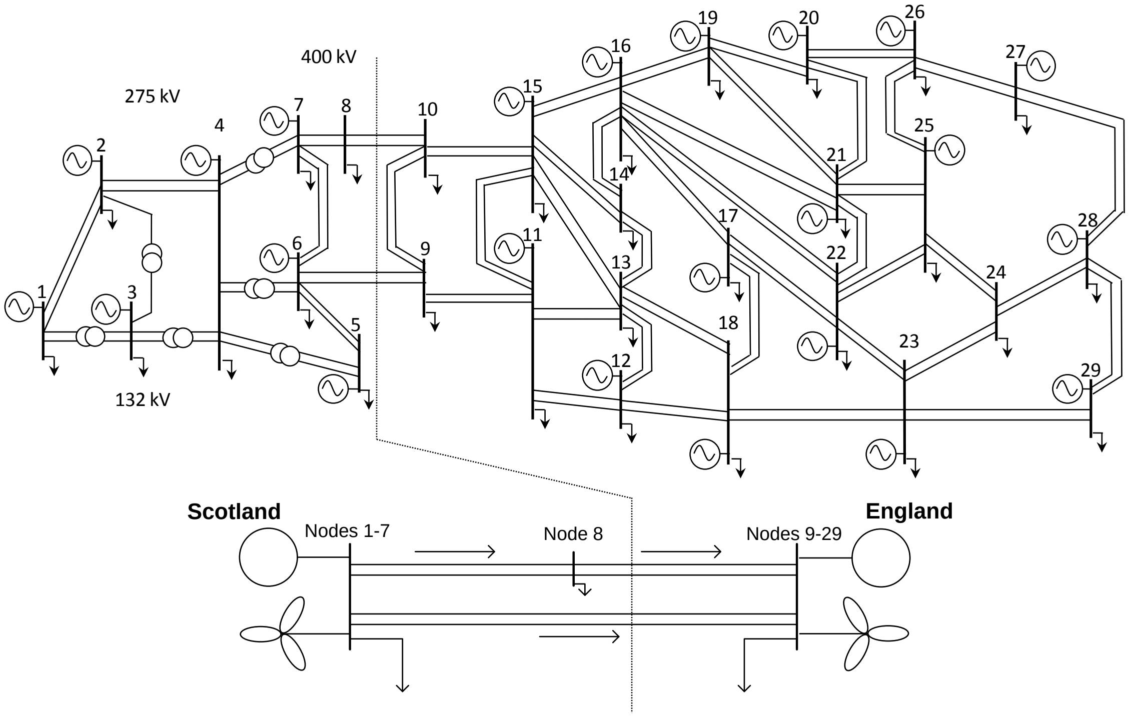

Figure 5.1: The equivalent 29-busbar GB transmission network (upper) and its mapping to a more simplified 3-busbar system (lower)

Table 5.1: System nodes

Node Number	Node Name	Node Number	Node Name	Node Number	Node Name
1	Beauly	11	Penwortham	21	Pelham
2	Peterhead	12	Deeside	22	Sundon/East Claydon
3	Errochty	13	Daines	23	Melksham
4	Denny/Bonnybridge	14	Th. Marsh/Stocksbridge	24	Bramley
5	Neilston	15	Thornton/Drax/Eggborough	25	London
6	Strathaven	16	Keadby	26	Kemsley
7	Torness	17	Ratcliffe	27	Sellindge
8	Eccles	18	Feckenham	28	Lovedean
9	Harker	19	Walpole	29	S.W.Penisula
10	Stella West	20	Bramford		

Based on the connection of about 20 GW of wind generation by 2020[22], the analysis considers 2 different levels of wind installed capacity that are defined below. Table 5.2 presents the associated wind installed capacity per node for each scenario.

(i) current scenario (centred on the current wind installed capacity); and

(ii) 2020 scenario (centred on 2020 wind installed capacity).

Table 5.2: Wind installed capacity scenarios per node and area

Wind installed capacity [MW]					
Node	Area	Current		2020	
1	Scotland	700	3080	7500	14550
2		50		500	
3		600		1500	
4		30		50	
6		1400		4000	
7		300		1000	
11	England	200	500	2000	5500
16		0		500	
19		0		1500	
27		300		1500	
Total		3580		20050	

The Value of Lost Load (VoLL), SPS utilisation prices and reserve prices represent typical values observed and are equal to 30 k£/MWh, 1 k£ per MW per event and 15 £/MW/h, respectively. Constraints prices are assumed to be cost-reflective, i.e. generators' outputs can be modified at a price equal to their fuel costs. Further generation prices together with generation minimum capacities and ramp rates are shown in Table 5.3. The generation installed capacity per technology is illustrated in Table 5.4.

Table 5.3: Minimum Stable Generation (MSG), ramp limits and fuel, bid and offer prices per technology

	Phisical values as [%] of total capacity		Price of [£/MWh]		
	MSG	Ramp up/down	Fuel	Bid	Offer
Wind	0%	0%	0	-50	N/A
Hydro	10%	100%	80	80	81
PS	10%	100%	200	200	201
CHP	40%	0%	0	-50	N/A
CCGT	40%	20%	30	30	31
Peaker	40%	20%	300	300	301
Coal	40%	10%	35	35	36
Nuclear	90%	0%	0	-1000	N/A
Interconnector	0%	0%	50	50	51

[22] One potential scenario for future wind development.

Table 5.4: Conventional generation installed capacity

Capacity [MW]	Node							
	1	2	3	4	5	6	7	10
Hydro	500	0	500	0	0	30	0	0
PS	300	0	0	400	0	0	0	0
CHP	0	10	0	300	0	0	0	0
CCGT	0	1500	0	0	20	0	0	2000
Peaker	0	0	0	0	0	0	0	0
Coal	0	0	0	2200	0	0	1000	500
Nuclear	0	0	0	0	1000	0	1200	1200
	11	12	15	16	17	18	19	20
Hydro	0	0	0	0	0	0	0	0
PS	0	2000	0	0	0	0	0	0
CHP	200	200	0	1200	0	200	0	0
CCGT	1000	2000	0	7000	0	0	3000	0
Peaker	0	0	0	0	0	0	0	0
Coal	2000	0	8000	4000	2000	2000	0	0
Nuclear	2400	1000	0	0	0	0	0	1200
	21	22	23	25	26	27	28	29
Hydro	0	0	0	0	0	0	0	0
PS	0	0	0	0	0	0	0	0
CHP	0	0	0	0	0	0	200	0
CCGT	500	500	4500	2000	3000	0	1500	1000
Peaker	0	0	100	1200	1300	0	0	100
Coal	0	0	4000	0	3000	0	0	0
Nuclear	0	0	500	0	0	1000	0	1200

	Scotland	England	Total
Hydro	1030	0	1030
PS	700	2000	2700
CHP	310	2000	2310
CCGT	1520	28000	29520
Peaker	0	2700	2700
Coal	3200	25500	28700
Nuclear	2200	8500	10700
Total	8960	68700	77660

For reliability purposes, the generation installed capacity shown in Table 5.4 is divided into:

(i) generation units of 1.2 GW for nuclear plants with a failure rate of 2 occ/yr. Also smaller units of 0.5 and 1 GW are used where suitable (with the same failure rate).

(ii) generation units of 0.2 and 0.5 GW for coal and CCGT plants with a failure rate of 18 occ/yr. Also, smaller units are considered where suitable with a failure rate of 0 (i.e. 100% reliable).

(iii) no division for further generation technologies since these are assumed to be 100% reliable.

For the network, the annual outage rates for fair and adverse weather were populated and provided by the 3 GB transmission licensees (i.e. National Grid, Scottish Power and Scottish and Southern Energy). These are the same as those utilised in Chapter 3 and shown in Table 3.2.

The network and generation reliability data are combined over an array of outages that ultimately permit the assessment of risk. These operating states include the occurrences of:

(a) all N-1 outages in generation (126),

(b) all N-1 outages in transmission (99),

(c) all N-2 outages of double circuits (49), and

(d) selected N-2 generation outages (outages of neighbouring generating units -125-).

Therefore, 399 outages (400 operating states, including intact system) are studied in the assessment. As in Chapter 3, outages of generation are considered independent and outages of transmission have common mode within a double circuit configuration. All outages are exponentially distributed and generation failures are assumed to be independent from the transmission failures. The equations utilised to obtain the ultimate outage probabilities are shown in Eq. 3.3.

With regard to the current network capacity, thermal line ratings are used for almost all circuits where post-fault ratings are 1.1765 times the pre-fault ones. Adjusted line ratings are assumed for the England-Scotland interconnector in order to represent the current stability constraints (i.e. 1.4 GW of post-fault line rating per circuit). Further network data such as resistances and reactances can be found in [73] (see Table 5.5).

Table 5.5: Network input data

Line	Resistance [p.u.]	Reactance [p.u.]	Lenght [km]	Post-fault rating [MW]	Line	Resistance [p.u.]	Reactance [p.u.]	Lenght [km]	Post-fault rating [MW]	Line	Resistance [p.u.]	Reactance [p.u.]	Lenght [km]	Post-fault rating [MW]
1-2	0.01220	0.02000	100	500	11-12	0.00010	0.00850	50	3300	21-25	0.00025	0.01000	25	2800
1-3	0.00700	0.15000	50	100	12-13	0.00096	0.01078	50	3100	21-25	0.00025	0.01000	25	2800
1-2	0.01220	0.02000	100	500	12-18	0.00074	0.00900	100	2400	21-20	0.00120	0.00480	50	2800
1-3	0.00700	0.15000	50	100	12-18	0.00097	0.00900	100	2400	21-20	0.00120	0.00480	50	2800
2-4	0.00040	0.06500	100	800	12-13	0.00096	0.01078	50	3100	21-19	0.00037	0.00590	50	3000
2-4	0.00040	0.06500	100	800	13-18	0.00049	0.00700	100	2400	21-19	0.00037	0.00590	50	2800
4-7	0.00211	0.01350	25	1100	13-18	0.00084	0.00700	100	2400	22-16	0.00178	0.01720	100	2000
4-6	0.00130	0.02300	25	1500	13-15	0.00137	0.02300	50	1200	22-16	0.00178	0.01720	100	2000
4-6	0.00130	0.02300	25	1100	13-15	0.00164	0.02300	50	1000	22-25	0.00037	0.00410	25	3300
4-5	0.00100	0.02400	25	1000	13-14	0.00107	0.01163	25	1000	22-25	0.00034	0.00410	25	3300
4-5	0.00100	0.02400	25	1000	13-14	0.00082	0.01201	25	1000	22-21	0.00019	0.00111	25	2800
4-7	0.00210	0.01350	25	1100	14-16	0.00050	0.01600	25	2600	22-21	0.00048	0.00610	25	2800
5-6	0.00085	0.01051	25	1400	14-16	0.00500	0.01800	25	600	23-29	0.00151	0.01820	25	2000
5-6	0.00151	0.01613	25	1400	15-16	0.00033	0.00520	25	2800	23-24	0.00086	0.00080	50	2800
6-9	0.00078	0.00852	100	1400	15-16	0.00016	0.00172	25	5500	23-24	0.00023	0.00070	50	4400
6-9	0.00078	0.00852	100	1400	15-14	0.00019	0.00222	25	5000	23-22	0.00055	0.00300	50	2800
7-8	0.00040	0.00010	25	1400	15-14	0.00018	0.00222	25	5000	23-22	0.00039	0.00300	50	2800
7-8	0.00040	0.00010	25	1400	16-19	0.00056	0.01410	50	2800	23-29	0.00151	0.01820	25	2000
7-6	0.00300	0.20000	25	1000	16-19	0.00056	0.01410	50	3800	24-28	0.00068	0.00700	25	2200
7-6	0.00300	0.20000	25	1000	17-16	0.00100	0.01072	50	2200	24-25	0.00104	0.00910	25	1400
8-10	0.00083	0.01750	50	1400	17-16	0.00100	0.01072	50	1900	24-25	0.00104	0.00910	25	1400
8-10	0.00083	0.01750	50	1400	17-22	0.00068	0.00970	50	2100	24-28	0.00068	0.00700	25	2200
9-11	0.00164	0.01630	100	1400	17-22	0.00069	0.00970	50	2100	25-26	0.00020	0.00570	50	7000
9-11	0.00164	0.01630	100	1400	18-17	0.00042	0.00180	50	3100	25-26	0.00020	0.00570	50	5500
9-10	0.00352	0.02453	50	900	18-17	0.00042	0.00180	50	3500	27-26	0.00020	0.00503	25	3100
9-10	0.00492	0.03430	50	800	18-23	0.00138	0.00960	50	2000	27-26	0.00020	0.00503	25	3100
10-15	0.00053	0.00835	100	4800	18-23	0.00117	0.00960	50	2000	28-27	0.00038	0.00711	100	3100
10-15	0.00052	0.00630	100	4000	20-26	0.00035	0.00230	50	2800	28-27	0.00038	0.00711	100	3100
11-15	0.00070	0.04200	50	2500	20-26	0.00035	0.00230	50	2800	29-28	0.00051	0.00796	50	2800
11-15	0.00099	0.04200	50	2500	20-19	0.00178	0.02130	50	1600	29-28	0.00051	0.00796	50	2800
11-13	0.00040	0.00520	50	2200	20-19	0.00132	0.01430	50	1600	3-4	0.00300	0.04100	50	600
11-13	0.00040	0.00520	50	2200	21-16	0.00145	0.01824	100	2800	3-4	0.00300	0.04100	50	600
11-12	0.00010	0.00850	50	3300	21-16	0.00145	0.01824	100	2800	3-2	0.03004	0.07700	100	700

The interconnection of the GB network with neighbouring countries is modelled through international interconnectors (presented in Table 5.6) which are assumed to resemble thermal generators and cannot provide corrective control services. This assumption should underestimate the benefits of a probabilistic framework and therefore will drive more conservative results (since in reality new interconnectors in GB –completed after 2005– have to provide mandatory frequency response [74]).

Table 5.6: Current (Moyle and France) and future (EastWest and BritNet) interconnectors

Interconnector		
Node	Name	Capacity [MW]
5	Moyle	500
12	EastWest	500
26	BritNet	1000
27	France	2000

With respect to the wind and demand profiles, these are the same as those previously presented in Chapter 3 through Figure 3.5 and Figure 3.6. The load distribution across the 29 nodes is obtained based on the demand snapshot shown in Table 5.7.

Table 5.7: Demand distribution (annual peak of 61.3 GW and load factor of 66%)

Node	Demand [MW]	Node	Demand [MW]	Node	Demand [MW]
1	500	11	3400	21	700
2	500	12	1200	22	1800
3	600	13	2500	23	4700
4	1300	14	1800	24	1400
5	500	15	2600	25	9700
6	1200	16	1600	26	1400
7	700	17	1100	27	500
8	100	18	5400	28	2800
9	100	19	2000	29	2600
10	2600	20	1000	TOTAL	56300

5.2.2 Planning timescale

Aligned with current network plans in GB [75], the study considers the possibility of adding two new High Voltage Direct Current (HVDC) lines of 2 GW each by 2020 and which add capacity to the England Scotland interconnector (and to further transmission corridors). The connection points of these two new lines are:

1. West bootstrap: between nodes 5 and 12 (i.e. between Neilston and Deeside areas)
2. East bootstraps: between nodes 2 and 10 (i.e. between Peterhead and Stella west areas)

The HVDC investment cost is equal to 38.9 k£/MW/yr and the HVDC links can be only built, if so, at the given capacity (lumpy investment –2 GW–). The existing AC transmission assets can be enhanced in lumps of 500 MW at a cost of 50 £/MW/km/yr and there is a constraint imposed to the circuits of the England-Scotland interconnector which can only be enhanced up to 2.2 GW of (post-fault) capacity per circuit[23].

One HVDC link (if installed) is considered with a failure rate of 1.4×10^{-3} occ/day (~1 occurrence every 2 years) regardless of weather conditions and with losses according to: $9.4 \times 10^{-6} F^2 + 13.93$ MW which represent the cable plus the converter losses. This equation results in a 2.5% of losses when transferring 2 GW and is consistent with the calculations in [76].

For the evaluation of the annual costs, a year of 8,736 hours (52 weeks) is represented through 200 operating conditions or snapshots which combine: 2 typical days (summer and winter), 5 demand levels per day, 2 types of weather conditions (fair and adverse) and 10 wind levels.

Snapshots' durations represent: 12 weeks of summer and 40 weeks of winter. Winter is composed of 88% and 12% of fair and adverse weather, respectively, and summer contains a fair/adverse weather ratio of 97%/3%. The characteristics of the operating conditions loaded in the model are presented in Table 5.8 to Table 5.11. The entire summer season is utilised to carry out maintenance activities on the circuits of the England-Scotland interconnector (2 weeks each circuit, when considering 4 AC and 2 HVDC circuits).

[23] Assuming that the maximum possible N-2 secured capacity after investment can be 4.4 GW (this is coherent with [76]).

Table 5.8: Snapshots utilised in the planning timescale -1/4

Snapshots	Duration [hrs]	Demand [p.u.]	Weather	Season	Wind	Maintenance
1	491.86	0.5632	fair	winter	5%	generation
2	98.37	0.6688	fair	winter	5%	generation
3	804.39	0.7568	fair	winter	5%	generation
4	13.32	1.0000	fair	winter	5%	generation
5	163.95	0.7040	fair	winter	5%	generation
6	361.63	0.5632	fair	winter	15%	generation
7	72.33	0.6688	fair	winter	15%	generation
8	591.42	0.7568	fair	winter	15%	generation
9	9.79	1.0000	fair	winter	15%	generation
10	120.54	0.7040	fair	winter	15%	generation
11	253.38	0.5632	fair	winter	25%	generation
12	50.68	0.6688	fair	winter	25%	generation
13	414.37	0.7568	fair	winter	25%	generation
14	6.86	1.0000	fair	winter	25%	generation
15	84.46	0.7040	fair	winter	25%	generation
16	177.65	0.5632	fair	winter	35%	generation
17	35.53	0.6688	fair	winter	35%	generation
18	290.53	0.7568	fair	winter	35%	generation
19	4.81	1.0000	fair	winter	35%	generation
20	59.22	0.7040	fair	winter	35%	generation
21	153.57	0.5632	fair	winter	45%	generation
22	30.71	0.6688	fair	winter	45%	generation
23	251.15	0.7568	fair	winter	45%	generation
24	4.16	1.0000	fair	winter	45%	generation
25	51.19	0.7040	fair	winter	45%	generation
26	145.75	0.5632	fair	winter	55%	generation
27	29.15	0.6688	fair	winter	55%	generation
28	238.36	0.7568	fair	winter	55%	generation
29	3.95	1.0000	fair	winter	55%	generation
30	48.58	0.7040	fair	winter	55%	generation
31	90.30	0.5632	fair	winter	65%	generation
32	18.06	0.6688	fair	winter	65%	generation
33	147.68	0.7568	fair	winter	65%	generation
34	2.45	1.0000	fair	winter	65%	generation
35	30.10	0.7040	fair	winter	65%	generation
36	74.46	0.5632	fair	winter	75%	generation
37	14.89	0.6688	fair	winter	75%	generation
38	121.77	0.7568	fair	winter	75%	generation
39	2.02	1.0000	fair	winter	75%	generation
40	24.82	0.7040	fair	winter	75%	generation
41	80.16	0.5632	fair	winter	85%	generation
42	16.03	0.6688	fair	winter	85%	generation
43	131.10	0.7568	fair	winter	85%	generation
44	2.17	1.0000	fair	winter	85%	generation
45	26.72	0.7040	fair	winter	85%	generation
46	21.65	0.5632	fair	winter	95%	generation
47	4.33	0.6688	fair	winter	95%	generation
48	35.41	0.7568	fair	winter	95%	generation
49	0.59	1.0000	fair	winter	95%	generation
50	7.22	0.7040	fair	winter	95%	generation

Table 5.9: Snapshots utilised in the planning timescale -2/4

Snapshots	Duration [hrs]	Demand [p.u.]	Weather	Season	Wind	Maintenance
51	67.07	0.5632	adverse	winter	5%	generation
52	13.41	0.6688	adverse	winter	5%	generation
53	109.69	0.7568	adverse	winter	5%	generation
54	1.82	1.0000	adverse	winter	5%	generation
55	22.36	0.7040	adverse	winter	5%	generation
56	49.31	0.5632	adverse	winter	15%	generation
57	9.86	0.6688	adverse	winter	15%	generation
58	80.65	0.7568	adverse	winter	15%	generation
59	1.34	1.0000	adverse	winter	15%	generation
60	16.44	0.7040	adverse	winter	15%	generation
61	34.55	0.5632	adverse	winter	25%	generation
62	6.91	0.6688	adverse	winter	25%	generation
63	56.51	0.7568	adverse	winter	25%	generation
64	0.94	1.0000	adverse	winter	25%	generation
65	11.52	0.7040	adverse	winter	25%	generation
66	24.22	0.5632	adverse	winter	35%	generation
67	4.84	0.6688	adverse	winter	35%	generation
68	39.62	0.7568	adverse	winter	35%	generation
69	0.66	1.0000	adverse	winter	35%	generation
70	8.07	0.7040	adverse	winter	35%	generation
71	20.94	0.5632	adverse	winter	45%	generation
72	4.19	0.6688	adverse	winter	45%	generation
73	34.25	0.7568	adverse	winter	45%	generation
74	0.57	1.0000	adverse	winter	45%	generation
75	6.98	0.7040	adverse	winter	45%	generation
76	19.88	0.5632	adverse	winter	55%	generation
77	3.98	0.6688	adverse	winter	55%	generation
78	32.50	0.7568	adverse	winter	55%	generation
79	0.54	1.0000	adverse	winter	55%	generation
80	6.63	0.7040	adverse	winter	55%	generation
81	12.31	0.5632	adverse	winter	65%	generation
82	2.46	0.6688	adverse	winter	65%	generation
83	20.14	0.7568	adverse	winter	65%	generation
84	0.33	1.0000	adverse	winter	65%	generation
85	4.10	0.7040	adverse	winter	65%	generation
86	10.15	0.5632	adverse	winter	75%	generation
87	2.03	0.6688	adverse	winter	75%	generation
88	16.61	0.7568	adverse	winter	75%	generation
89	0.27	1.0000	adverse	winter	75%	generation
90	3.38	0.7040	adverse	winter	75%	generation
91	10.93	0.5632	adverse	winter	85%	generation
92	2.19	0.6688	adverse	winter	85%	generation
93	17.88	0.7568	adverse	winter	85%	generation
94	0.30	1.0000	adverse	winter	85%	generation
95	3.64	0.7040	adverse	winter	85%	generation
96	2.95	0.5632	adverse	winter	95%	generation
97	0.59	0.6688	adverse	winter	95%	generation
98	4.83	0.7568	adverse	winter	95%	generation
99	0.08	1.0000	adverse	winter	95%	generation
100	0.98	0.7040	adverse	winter	95%	generation

Table 5.10: Snapshots utilised in the planning timescale -3/4

Snapshots	Duration [hrs]	Demand [p.u.]	Weather	Season	Wind	Maintenance
101	151.68	0.4469	fair	summer	5%	line + generation
102	21.67	0.5687	fair	summer	5%	line + generation
103	227.40	0.6684	fair	summer	5%	line + generation
104	54.05	0.6314	fair	summer	5%	line + generation
105	65.00	0.5806	fair	summer	5%	line + generation
106	111.52	0.4469	fair	summer	15%	line + generation
107	15.93	0.5687	fair	summer	15%	line + generation
108	167.19	0.6684	fair	summer	15%	line + generation
109	39.74	0.6314	fair	summer	15%	line + generation
110	47.79	0.5806	fair	summer	15%	line + generation
111	78.13	0.4469	fair	summer	25%	line + generation
112	11.16	0.5687	fair	summer	25%	line + generation
113	117.14	0.6684	fair	summer	25%	line + generation
114	27.84	0.6314	fair	summer	25%	line + generation
115	33.49	0.5806	fair	summer	25%	line + generation
116	54.78	0.4469	fair	summer	35%	line + generation
117	7.83	0.5687	fair	summer	35%	line + generation
118	82.13	0.6684	fair	summer	35%	line + generation
119	19.52	0.6314	fair	summer	35%	line + generation
120	23.48	0.5806	fair	summer	35%	line + generation
121	47.36	0.4469	fair	summer	45%	line + generation
122	6.77	0.5687	fair	summer	45%	line + generation
123	71.00	0.6684	fair	summer	45%	line + generation
124	16.88	0.6314	fair	summer	45%	line + generation
125	20.30	0.5806	fair	summer	45%	line + generation
126	44.95	0.4469	fair	summer	55%	line + generation
127	6.42	0.5687	fair	summer	55%	line + generation
128	67.38	0.6684	fair	summer	55%	line + generation
129	16.02	0.6314	fair	summer	55%	line + generation
130	19.26	0.5806	fair	summer	55%	line + generation
131	27.85	0.4469	fair	summer	65%	line + generation
132	3.98	0.5687	fair	summer	65%	line + generation
133	41.75	0.6684	fair	summer	65%	line + generation
134	9.92	0.6314	fair	summer	65%	line + generation
135	11.93	0.5806	fair	summer	65%	line + generation
136	22.96	0.4469	fair	summer	75%	line + generation
137	3.28	0.5687	fair	summer	75%	line + generation
138	34.42	0.6684	fair	summer	75%	line + generation
139	8.18	0.6314	fair	summer	75%	line + generation
140	9.84	0.5806	fair	summer	75%	line + generation
141	24.72	0.4469	fair	summer	85%	line + generation
142	3.53	0.5687	fair	summer	85%	line + generation
143	37.06	0.6684	fair	summer	85%	line + generation
144	8.81	0.6314	fair	summer	85%	line + generation
145	10.59	0.5806	fair	summer	85%	line + generation
146	6.68	0.4469	fair	summer	95%	line + generation
147	0.95	0.5687	fair	summer	95%	line + generation
148	10.01	0.6684	fair	summer	95%	line + generation
149	2.38	0.6314	fair	summer	95%	line + generation
150	2.86	0.5806	fair	summer	95%	line + generation

Table 5.11: Snapshots utilised in the planning timescale -4/4

Snapshots	Duration [hrs]	Demand [p.u.]	Weather	Season	Wind	Maintenance
151	4.69	0.4469	adverse	summer	5%	line + generation
152	0.67	0.5687	adverse	summer	5%	line + generation
153	7.03	0.6684	adverse	summer	5%	line + generation
154	1.67	0.6314	adverse	summer	5%	line + generation
155	2.01	0.5806	adverse	summer	5%	line + generation
156	3.45	0.4469	adverse	summer	15%	line + generation
157	0.49	0.5687	adverse	summer	15%	line + generation
158	5.17	0.6684	adverse	summer	15%	line + generation
159	1.23	0.6314	adverse	summer	15%	line + generation
160	1.48	0.5806	adverse	summer	15%	line + generation
161	2.42	0.4469	adverse	summer	25%	line + generation
162	0.35	0.5687	adverse	summer	25%	line + generation
163	3.62	0.6684	adverse	summer	25%	line + generation
164	0.86	0.6314	adverse	summer	25%	line + generation
165	1.04	0.5806	adverse	summer	25%	line + generation
166	1.69	0.4469	adverse	summer	35%	line + generation
167	0.24	0.5687	adverse	summer	35%	line + generation
168	2.54	0.6684	adverse	summer	35%	line + generation
169	0.60	0.6314	adverse	summer	35%	line + generation
170	0.73	0.5806	adverse	summer	35%	line + generation
171	1.46	0.4469	adverse	summer	45%	line + generation
172	0.21	0.5687	adverse	summer	45%	line + generation
173	2.20	0.6684	adverse	summer	45%	line + generation
174	0.52	0.6314	adverse	summer	45%	line + generation
175	0.63	0.5806	adverse	summer	45%	line + generation
176	1.39	0.4469	adverse	summer	55%	line + generation
177	0.20	0.5687	adverse	summer	55%	line + generation
178	2.08	0.6684	adverse	summer	55%	line + generation
179	0.50	0.6314	adverse	summer	55%	line + generation
180	0.60	0.5806	adverse	summer	55%	line + generation
181	0.86	0.4469	adverse	summer	65%	line + generation
182	0.12	0.5687	adverse	summer	65%	line + generation
183	1.29	0.6684	adverse	summer	65%	line + generation
184	0.31	0.6314	adverse	summer	65%	line + generation
185	0.37	0.5806	adverse	summer	65%	line + generation
186	0.71	0.4469	adverse	summer	75%	line + generation
187	0.10	0.5687	adverse	summer	75%	line + generation
188	1.06	0.6684	adverse	summer	75%	line + generation
189	0.25	0.6314	adverse	summer	75%	line + generation
190	0.30	0.5806	adverse	summer	75%	line + generation
191	0.76	0.4469	adverse	summer	85%	line + generation
192	0.11	0.5687	adverse	summer	85%	line + generation
193	1.15	0.6684	adverse	summer	85%	line + generation
194	0.27	0.6314	adverse	summer	85%	line + generation
195	0.33	0.5806	adverse	summer	85%	line + generation
196	0.21	0.4469	adverse	summer	95%	line + generation
197	0.03	0.5687	adverse	summer	95%	line + generation
198	0.31	0.6684	adverse	summer	95%	line + generation
199	0.07	0.6314	adverse	summer	95%	line + generation
200	0.09	0.5806	adverse	summer	95%	line + generation

Apart from line maintenance, generation maintenance is also modelled using the availability factors per generation technology presented in Table 5.12 to limit the overall generation output of a particular technology in an area (i.e. England and Scotland).

Table 5.12: Generation availability per technology in each area (England and Scotland)

	Availability	
	Winter	Summer
Wind	N/A	N/A
Hydro	98%	77%
PS	98%	77%
CHP	73%	57%
CCGT	96%	78%
Peaker	95%	81%
Coal	95%	80%
Nuclear	88%	79%
Interconnector	99%	91%

5.3 Results and analysis of optimum network operation

5.3.1 Deterministic versus probabilistic transfers

When considering the current wind installed capacity, a (nearly) peak demand condition of 56.2 GW and 100% wind availability; the system is balanced by about 2610 MW with the associated constraints cost of 4 k£/30min in order to transfer circa 2.4 GW through the interconnector and comply with an N-2 deterministic criteria as shown in Figure 5.2.

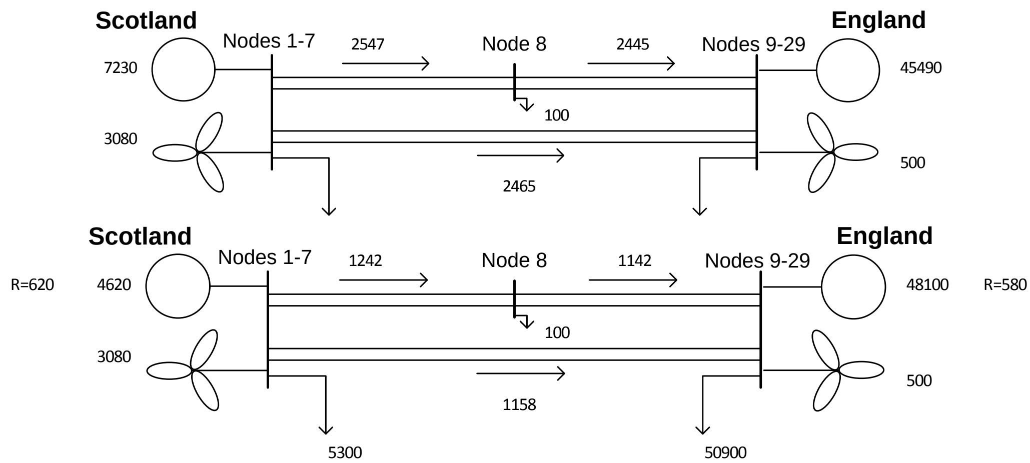

Figure 5.2: Unconstrained (upper) and constrained (lower) dispatches with deterministic security (generation, transfers and reserve levels in MW)

If the security criteria is changed by the proposed probabilistic one, transfers can be increased up to 4.4 GW in fair weather with the associated constraints cost of 1.5 k£/30min. In this case, the system is only balanced by about 590 MW as shown in Figure 5.3.

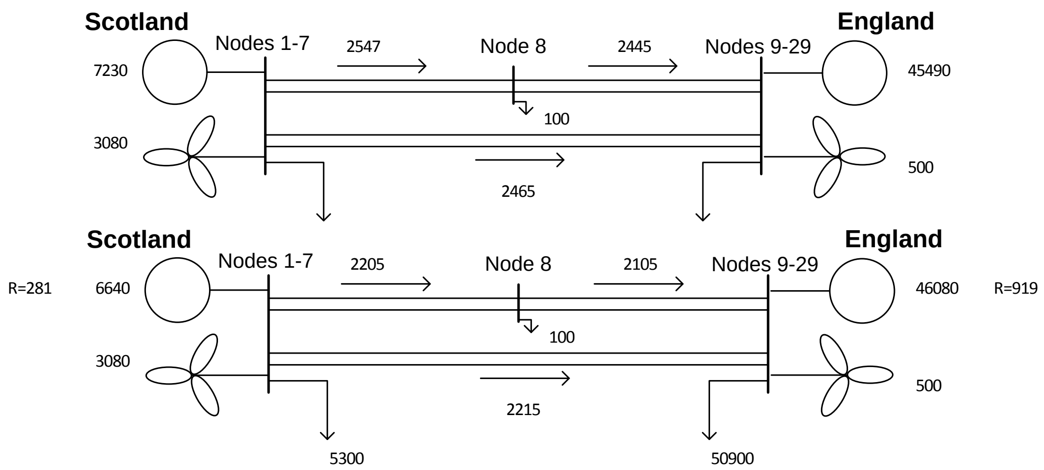

Figure 5.3: Unconstrained (upper) and constrained (lower) dispatches with probabilistic security under fair weather (generation, transfers and reserve levels in MW)

In the deterministic case, although the link has a theoretical limit of 2.8 GW, constraints within England and Scotland (also triggered by deterministic security) impede increases in transfers at this level. In effect, if higher transfers are accepted in the interconnector, then the N-2 failure of the line between nodes 10-15 (i.e. line 10-15) in England will make line 9-11 become overloaded. Constraining off generation in node 10 in the intact system in order to avoid this situation is also uneconomical. In addition, there are internal congestions within Scotland that do not allow cheaper generation in node 2 to be dispatched (e.g. under the N-2 outage of line 2-4, line 1-3's limit is hit; this trigger the curtailment of CCGTs in node 2 by 865 MW).

In the probabilistic case, transfers above the limit of 2.8 GW can be permitted by utilising post-fault actions such as generation reserve up/down (i.e. generation re-dispatching) and SPS to intertrip generation and demand. For example, a combination of corrective actions can be undertaken if the double outage of line 6-9 occurs (i.e. AC west interconnector):

(i) 995 MW of intertripping in node 7;

(ii) 624 MW of reserve down in nodes 2,4,5 and 7;

(iii) 919 MW of reserve up in nodes 11,15 and 16; and

(iv) 700 MW of demand shedding in nodes 8,9 and 21.

The loss of importing power to England goes up to 1619 MW of which only 700 MW corresponds to demand shedding.

5.3.2 Changes in constraints costs

Given that constraints costs, due to restricted power transfers, will be the highest when wind power is constrained, it may be more cost-effective to accept higher power transfers in such conditions. In effect, the simulation of 2020 wind installed capacity at maximum output over the current network will lead to an increase from 4.4 GW to 4.7 GW through the England Scotland interconnector (i.e. 100% network utilisation). Furthermore, this increased transfer minimises wind curtailments to circa 7 GW, instead of the wind curtailment of 9 GW that arises in the deterministic case.

This is in contrast with the present deterministic operating standards that would keep the power transfer limit at a single fixed level for all wind output conditions.

5.3.3 Changes in weather conditions

In adverse weather, transfers are constrained to secure system operation against circuit failures that become more probable. Furthermore, the occurrence of adverse weather may have different impacts on transfers if this weather condition is affecting the entire network or only parts of it. Different transfer levels that are optimal under a probabilistic framework are shown in Figure 5.4.

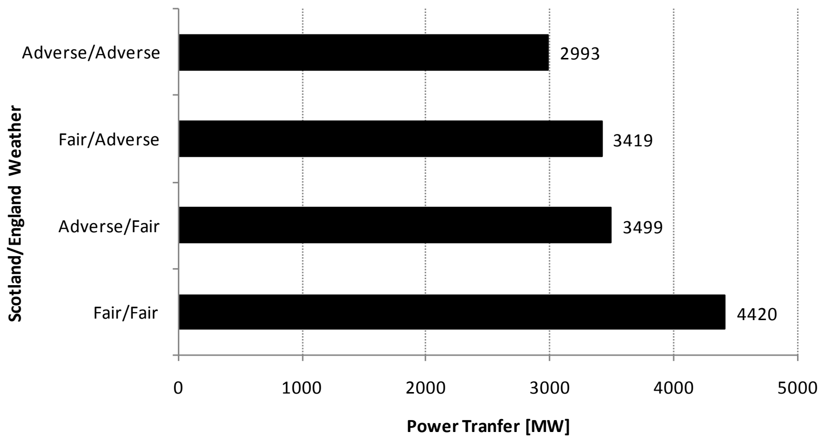

Figure 5.4: Probabilistic transfers in the current transmission network under current wind installed capacity, (nearly) peak demand and full wind output

It can be observed that the current deterministic limit is, indeed, nearly optimum under an adverse weather condition. However, higher power transfers can be allowed by the System Operator (SO) if fair weather conditions affect part of GB.

This is not recognized in the current deterministic standards.

Considering what has been pointed out in Section 5.3.2, possible correlations between high wind outputs and adverse weather have to be analysed within the probabilistic framework.

5.3.4 Generation support

From Figure 5.2 and Figure 5.3, it can be observed that both deterministic and probabilistic solutions commit the same amount of generation reserves (1.2 GW) under the current wind installed capacity condition. This level of reserve is justified in order to secure the system against the outages of the biggest generation units that, if no sufficient reserve is held, can drive demand shedding actions. It is worthwhile mentioning that while the volume of reserve is forced to cover the largest generator's outage under the deterministic framework, under the probabilistic framework the ultimate volume of reserve naturally arises due to the likelihood of generation (and transmission) outages and the VoLL.

In spite of the previous similarity, the allocation of generation reserve across the network presents significant differences between the deterministic and probabilistic methods. This is so given that, in the probabilistic method, generation reserve is also utilised to cope with transmission outages and facilitate the operation of SPS. This fact ultimately leads to higher levels of reserve in the importing area (919 MW of reserve in England with probabilistic security versus 580 MW of reserve in England with deterministic security).

As detailed in Section 3.4.2.3, it is also worthwhile to mention that to avoid situations with excessive risk exposure (e.g. during adverse weather), higher transfers (i.e. lower levels of network redundancy) can be accompanied by the holding of larger net amounts of generation reserves.

This is in contrast with the present deterministic standards that would keep generation reserves to only deal with outages and uncertainties related to generation.

5.3.5 Operational costs (O) and risks (X)

From the analysis of the full operational cost function and taking consideration of a comprehensive array of outages that can occur (i.e. 399), it is possible to demonstrate that the increases in risks do not compensate the higher benefits gained when accepting, in certain operating conditions, increased power transfers in the transmission network. This is illustrated in Table 5.13.

Table 5.13: O + X costs in the present GB network

Cost of [k£/30mins]	Deterministic		Probabilistic	
	Fair weather	Adverse weather	Fair weather	Adverse weather
constraints	4.00	4.00	1.50	2.20
reserve holding	9.00	9.00	9.00	9.00
reserve and intertrip utilisation	0.60	0.60	0.70	0.60
X	0.01	0.01	0.15	0.01
Total	13.61	13.61	11.35	11.81

The total O+X cost difference between the probabilistic and deterministic case increases in the presence of higher wind penetration. This will be detailed next in Section 5.4.2.

5.3.5.1 Deterministic risk allocation across the network

While in the probabilistic approach demand shed arises naturally and heterogeneously across the network, in the deterministic optimisation demand shed is minimised to zero under the occurrence of credible events. However, as demand shedding may be exercised under outages outside the aforementioned credible list, different network locations are exposed to diverse levels of risks even under the deterministic framework. For example, Table 5.14 shows how demand is curtailed if different N-2 generation outages occur. Because of it is an importing area, demand must be curtailed in England for most of the outages in order to balance demand and supply. There are also generation outages that can be balanced by curtailing demand either in England or Scotland. Overall, more than 75% of the risk under N-2 generation events is associated with demand curtailments in England. This particular risk assessment reflects the consideration of 4950 outages (all N-2 generation outages).

Table 5.14: Risk allocation for N-2 generation outages in (nearly) peak demand condition and 100% wind available (current scenario)

	No.	Demand shedding per outage [interval in MW]	Total X [£/30mins]	%
Outages that must be balanced by shedding demand in England	660	500 - 1200	1026	76%
Outages that must be balanced by shedding demand in Scotland	0	0	0	0%
Outages that can be balanced by shedding demand anywhere	285	200 - 1200	330	24%
Outages that do not require demand being shed	4005	0	0	0%
Total	*4950*		*1356*	*100%*

Outages that must be balanced by demand curtailments in England are the ones associated with the simultaneous failure of two units in England where at least one of them corresponds to a large nuclear plant (1.2 GW).

Regarding network outages, although the risk associated with N-3 line outages (and beyond) is significantly lower, it is still possible to demonstrate that most of it is allocated to England. This is especially true in a single boundary representation of the system where all the risk is allocated (as in the generation outages case) in the importing area, i.e. England.

This demonstrates that deterministic operation is subject to a diverse risk profile across the network which is neither quantified nor recognised within the framework.

5.4 Results and analysis of optimum network enhancements

5.4.1 Capacity enhancement

The application of operational measures or corrective control to deliver further network capacity to network users can displace, totally or in part, the need for network investment. Therefore, the effects of increased transfers in certain operating condition (e.g. high wind availability and/or fair weather) have to be quantified in a year-round fashion under an array of potential scenarios and compared with deterministic transmission enhancements.

In GB, various benefits can be observed when applying probabilistic methods for network investment, the savings in the investment of HVDC network assets being the most notable. Under the current deterministic security standards and in line with other cost-benefit studies such as the one in [76], it is demonstrated that both HVDC bootstraps are needed in order to integrate the amount of wind installed capacity given in Table 5.2. In contrast, it is also proved that the east bootstrap is not necessary by 2020 if corrective actions are optimally implemented within the proposed probabilistic framework. These results are displayed in Table 5.15.

Table 5.15: Transmission enhancements under probabilistic and deterministic security

Link	Transmission enhancements	
	Probabilistic [MW]	Deterministic [MW]
Line 6-9	680 x 2	680 x 2
Line 7-8	680 x 2	680 x 2
Line 8-10	680 x 2	680 x 2
DC west	2000	2000
DC east	0	2000

This outcome proves that the higher transmission capacity made available to users through the deployment of operational measures in the probabilistic framework can actually displace the need for 2 GW of transmission investment. More details about network investments can be found in Appendix E. This saving in transmission investment, however, will be accompanied by an increase in the cost of operating the network. This is assessed next.

5.4.2 Full enhancement costs (T), operational costs (O) and risks (X)

The assessment below shows that costs are significantly lower when applying probabilistic security. Although there is an increase in the levels of risk, this is not considerable and is lower than the levels of cost saving. In effect, the net cost saving has two important components: first, there is a saving in the cost of investment given that more capacity is released in operational timescales by using operational measures, and second there is a saving in the cost of constraints since network operators can still manage to accept higher power transfers in the reduced network. Total costs can be observed in Table 5.16.

Table 5.16: Full T+O+X costs for probabilistic and deterministic security

[Mill£/year]	Cost of investment	Cost of constraints	Cost of reserve holding	Cost of reserve and intertrip utilisation	Cost of X	Total
Probabilistic	145	37	80	4	2	268
Deterministic	247	52	79	3	< 1	382

In this exercise, levels of generation reserve are not increased because of wind uncertainty. In reality, increased wind outputs will be accompanied by increased generation reserve which can be also shared and thus utilised to deal with transmission outages. This fact will enhance the benefits of exercising a probabilistic framework for security in reality as proved in Section 3.4.2.4.

5.4.3 Wind integration

The levels of wind curtailment in the resulted optimum networks derived with both probabilistic and deterministic security has been assessed. To do so, two measures have been used: the volume of wind power being constrained off during peak demand and (nearly) peak wind output (fair and adverse weather); and the volume of wind energy being constrained off in a year. These results are shown in Table 5.17.

Table 5.17: Wind generation and curtailments under both deterministic and probabilistic (same for fair and adverse weather) solutions in MW (upper) and GWh (lower)

Node	Unconstrained generation [MW]	Probabilistic curtailement [MW]	Deterministic curtailement [MW]
1	7125	266	1463
2	475	0	0
3	1425	154	0
4	48	0	0
6	3800	0	0
7	950	0	0
11	1900	0	0
27	1425	0	0
16	475	0	0
19	1425	0	0
Total	*19048*	*420*	*1463*

Node	Unconstrained generation [GWh]	Probabilistic curtailement [GWh]	Deterministic curtailement [GWh]
1	19718	283	544
2	1315	0	0
3	3944	6	29
4	131	0	0
6	10516	516	438
7	2629	0	142
11	5258	0	0
27	3940	0	0
16	1315	0	0
19	3944	0	0
Total	*52710*	*805*	*1154*

It can be seen that the wind curtailments in the deterministic framework are higher than in the probabilistic framework. This is because the maximum N-2 theoretical limit of the England-Scotland interconnector is equal to 2.2 x (4-2) AC GW + 2.3 x 2 HVDC GW = 9 GW[24] which is insufficient to transfer the net export from the zero-marginal cost renewables in Scotland (i.e. ~11.6 GW –17 GW of wind, CHP and nuclear minus 5.4 GW of demand–). This demonstrates that to permit power transfers above 9 GW in order to offset potential wind curtailment, deterministic standards have to be derogated during particular conditions.

5.4.4 Account of network losses

In the previous analyses, the cost of transmission constraints and generation reserves in the intact system was balanced against an array of expected costs, including the risk of demand interruptions. In this section the cost of transmission losses in the intact system is also included.

The overall cost of losses may become important because it is substantially higher than other cost components. However, it is possible to demonstrate that in this case the cost increase associated with losses under a probabilistic framework is not high enough to offset the benefits pointed out earlier in this study. In fact, Table 5.18 shows the annual costs comparison of the probabilistic and deterministic planning solutions where the benefits of the probabilistic framework (i.e. in terms of cost savings) are still higher, even after losses consideration.

Table 5.18: Full T+O+X costs for probabilistic and deterministic security with transmission losses

[Mill£/year]	Cost of investment	Cost of constraints	Cost of reserve holding	Cost of losses	Cost of reserve and intertrip utilisation	Cost of X	Total
Probabilistic	145	37	80	291	4	2	559
Deterministic	247	52	79	262	3	< 1	644

[24] Post-fault line rating

Losses were calculated based on the resistances given in Table 5.5 when escalating them by a factor of 1.5[25] in order to include the variable losses of the remaining lines which are not represented in the 29-busbar system. In addition some resistance values were decreased proportionally to the capacity enhancements undertaken in the planning exercise.

Expectedly, the losses differential between the probabilistic and deterministic dispatch solutions is larger under fair weather conditions. This is so since higher levels of network utilisation are accepted in the probabilistic framework under fair weather. In addition, this difference rises under high levels of wind outputs for the same reason mentioned before. These two effects can be observed in Figure 5.5.

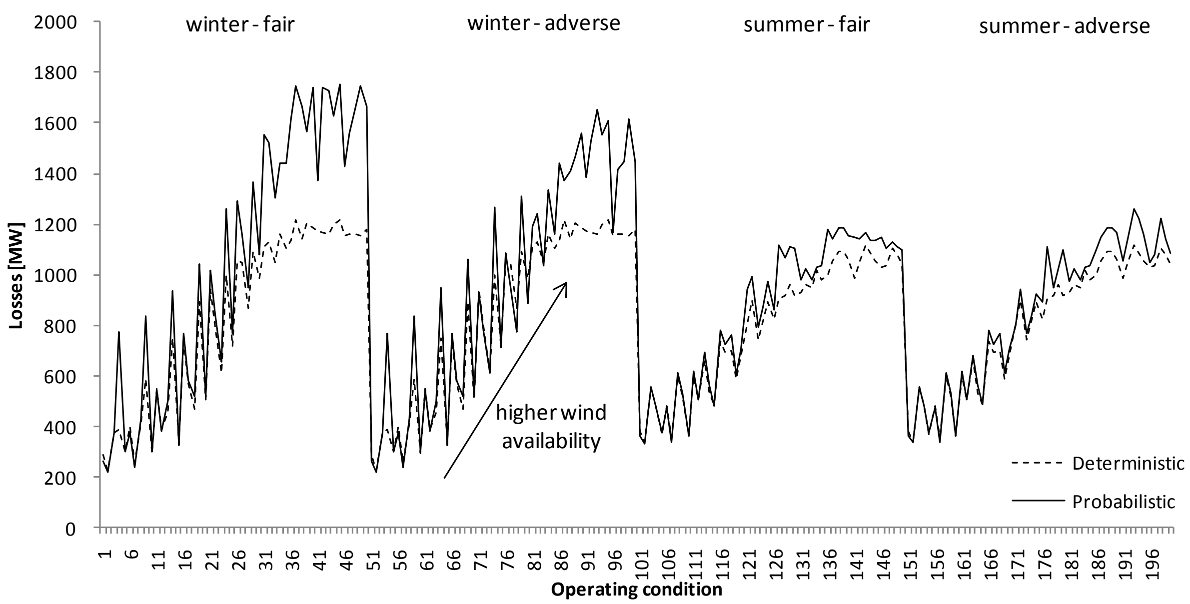

Figure 5.5: System variable losses of the deterministic and probabilistic solutions in 2020

The aforementioned level of utilisation is given by the ratio of the net transfer divided by the volume of network assets. Thus, sometimes the higher utilisation associated with the probabilistic solution mentioned above is driven by higher power transfers, especially under fair weather and high wind availability. At some other times this higher utilisation is driven by the lower volume of network assets, especially under adverse weather and low/mid wind availability, where transfers in the deterministic solution may become higher. These effects can be observed in Figure 5.6.

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[25] This factor (1.5) was calibrated in order to obtain the present level of losses in the system under the current wind scenario (according to [76], variable losses are about 1.5% of demand during the peak condition. These do not include GSP transformers losses, fixed losses and generators' transformers losses which are assumed to be the same under both the deterministic and probabilistic calculations).

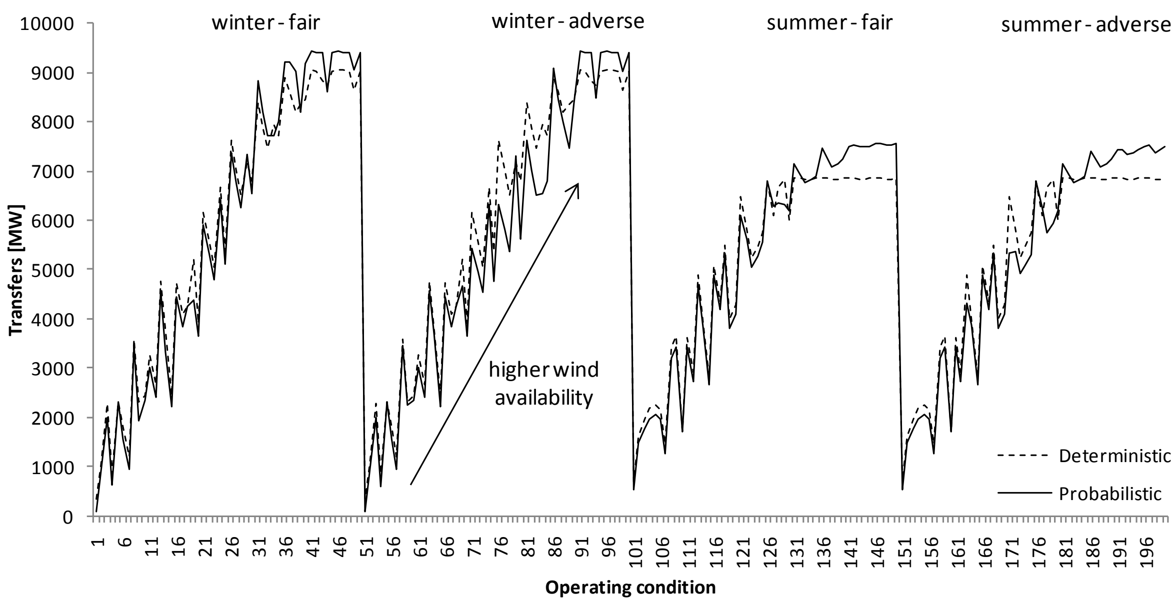

Figure 5.6: Net transfers through the England-Scotland boundary (including DC links) of the deterministic and probabilistic solutions in 2020

Given that losses represent a large proportion of the full annual costs, there may be situations in which these can justify either lowering the transfers or increasing the levels of network investment. This is recommended for future research.

5.5 Limitation of the case studies

The results obtained suggest that there is potentially a large benefit of moving away from the current deterministic security framework. However, the presented results should be taken in the context of a number of simplifying assumptions made. The actual value of the probabilistic approach in any particular system will be affected by several factors such as: the development of demand response policies which may reveal more information with respect to VoLL across different consumer types; VoLL that may vary widely across different consumer types; the effect of dynamic or stability constraints that will become increasingly more important with increased power transfers; application of dynamic line ratings; correlation of weather and wind generation condition. Conceptually, however, these effects could be integrated within the probabilistic operational standards and this is recommended for future investigations.

Note also that the simulations carried out in this thesis assessing costs associated with deterministic standards are based on the assumption that they are applied inflexibly. In practice, there may be situations where they are relaxed and accommodated with other obligations in a discretional basis (i.e. derogation of security standards). Nevertheless, even when taking account of this, we believe that the proposed probabilistic method has the potential of significant cost savings.

5.6 Conclusions

This chapter quantifies various benefits of the probabilistic framework proposed in earlier chapters for a new 29-busbar GB network. In addition, it also illustrates the problems of the current deterministic standards.

First, transfers in a probabilistic framework can be tuned more precisely according to actual costs and risks and therefore changes in weather and wind availability. It was demonstrated that higher wind outputs and fairer weather conditions, even if these affect part of GB, can justify increased utilisation of the GB network. Second, higher transfers can be accompanied by enlarged volumes of generation reserves in England (i.e. the importing area) that can facilitate the exercise of post-fault balancing actions after a transmission outage occurs. Thirdly, it was also shown that England is various times more exposed than Scotland to demand curtailment events under the deterministic standards. This proves that the uneven distribution of risk is not a characteristic of the probabilistic framework only and is a natural feature in power systems.

For network enhancements, the application of the probabilistic method brings important savings, especially in the investment of HVDC infrastructure. It is shown that with less network assets, the probabilistic framework will curtail less wind power compared to a deterministic framework, regardless of the increased network investment driven by the latter.

Finally, the increased risk to which demand is exposed in GB under the proposed probabilistic framework was demonstrated in comparison to the deterministic standards, can be limited if the right set of preventive (e.g. allocation of reserve) and corrective actions (e.g. intertripping scheme of demand and/or generation) is deployed.

CHAPTER 6: Concluding remarks and further work

6.1 Summary of achievements

This thesis developed a fully integrated economic and reliability probabilistic approach for network operation and expansion along with an array of studies that demonstrate its benefits. Quantifications are based on optimisation modelling techniques which have been packaged into T+O+X. This model has served to estimate the costs and risks refer to the aforementioned probabilistic framework in a number of network configurations, including a new 29-busbar representation of the GB transmission system. Additionally, the models developed can also replicate the outputs of a deterministic SC-OPF (in its preventive and corrective mode) and therefore has also served to compare the benefits and costs under both schemes.

This thesis has also investigated the latest trends in network security standards and the use of operational measures based on generation and demand response to deal with network outages and hence defer or displace the need for new network investment.

The main contribution of the work carried out can be summarised as follows:

1. *The development of a comprehensive security framework for network operation that permits the delivery of the efficient amount of network capacity to users that balances costs and risks in the presence of high penetration of wind*. This probabilistic framework was presented (in Chapter 3) and evaluated against a set of sensitivities with respect to wind outputs, weather conditions, reserve availabilities and prices, demand levels, etc. We demonstrated that the optimum levels of network utilisation should increase during high wind conditions (particularly if these would increase network constraints costs) and/or during favourable weather conditions. Also, higher levels of network utilisation can be achieved in case that increased generation reserves are deployed to deal with both unpredictability of wind generation outputs and post-fault transmission constraints management. In contrast, network utilisation levels will need to reduce in case of adverse weather condition and/or SPS malfunctions. We also demonstrated that the levels of risks associated to the proposed

framework can be limited (and even reduced) by deploying the right set of generation- and demand-based operational measures (e.g. holding higher volumes of generation reserve in the intact system and/or curtailing generation or demand with a SPS after an outage occurs).

2. *The expansion of the framework above to planning timescales in order to assess the economic value of the support from operational measures to deferring or displacing (partially or totally) the need for new network investment*. We demonstrated (in Chapter 4) that a network investment can be potentially substituted if more cost-effective operational measures can be deployed. A set of operational measures can enhance the utilisation of the existing assets, reduce network constraint costs and maintain system reliability at economically efficient levels. Furthermore, we observed that the overall network costs will depend on the adopted network planning approach, i.e. deterministic or probabilistic and that, through a probabilistic framework, savings can be achieved in both investment and constraints costs at the same time. Generation reserve costs remains similar in the two approaches albeit their physical allocation across the network changes in order for the probabilistic solution to facilitate higher network utilisation and lower investments.

   Although the proposed probabilistic planning methodology is by definition more efficient than the deterministic one, we demonstrate that the former can be also less risky. In fact, we identified some major flaws of the deterministic framework that can in some cases lead to both:

   a. more risky operation;
   b. incorrect allocation of network reinforcements

3. *The development of modelling concepts and techniques applicable for large-scale network optimisations*. Large amount of scenarios that need to be studied (of the order of thousands which are composed of a combination of operating states and operating conditions) was tackled by means of a filtering technique able to identify the most relevant outages that drive the probabilistic operational and planning solutions and so reduce the computational burden. In this context, we demonstrated (in Chapter 4) that the same optimum decision that is obtained by using hundreds of outages can be reached by using a relatively small subset of events. This list of relevant outages can be also utilised to rank the importance of each network component according to its contribution to system risk.

   After the relevant outages are identified, we load them in the planning formulation developed that is based on a Benders decomposition in which system operation is optimised (slave routine) for every network capacity trial (master routine). The Benders algorithm allowed us to improve the performance of the optimisation in two manners:

a. large networks that could not be optimised without decoupling the optimisation (one-go T+O+X optimisation) because of lack of sufficiently large RAM memory, can now become solvable
b. the optimisation process can be now run in parallel, speeding up the computational times.

In addition, further techniques in the form of simple heuristics demonstrated to be successful in lowering the computational burden and reaching sufficiently accurate results.

4. *The application of the proposed framework on a simplified GB transmission system*. The benefits and costs associated to the proposed approach were evaluated on a 29-busbar representation of the GB system. We showed the effects of intra-area congestion, multiple simultaneous weather conditions and the allocation of reserve generation across the system, among others, on network transfers, reinforcements, costs and risks. We demonstrated (in Chapter 5) that the application of the proposed framework in GB can be beneficial in terms of the savings in HVDC network assets. We also demonstrate that the levels of wind curtailment under the deterministic framework will be higher even if a scenario of increased network investment is realised.

5. *The development of a framework compatible with the concept of smart grid*. Advances in information and communication technologies will enable network operators to release further network capacity to users through “smart” solutions rather than through asset-heavy investments. This is the fundamental characteristic of both the framework proposed and the associated model. In light of the concern about cascading failures driven by the malfunction of corrective actions, we model the possibility of curtailing various amounts of demand (at a given set of probabilities) after a corrective action failure occurs. Although this was done only over a 2-busbar system, the fundamental principles presented to deal with the reliability levels of corrective actions can be extrapolated on a larger network. This is recommended for future research (see more details in Section 6.2.1.1).

6.2 Further work

6.2.1 Modelling

6.2.1.1 Non-optimum demand shedding

The introduction of new network or smart grid technology, that can provide network capacity through operational measures or non-network solutions, has raised a new concern related to the levels of reliability associated to information technology and communication equipments. Indeed, the introduction of new technology can potentially pose additional operating risk as corrective actions may fail to operate correctly due to inappropriate settings, corrupted data, communication delay, etc. This risk needs to be understood, quantified, and managed to ensure that the integrity and security of the overall system is not compromised. Efficiently managing risks associated with the increased application of operational measures is important for the future development and implementation of alternative network control and design philosophies.

The modelling challenge in this respect refers to the ability to study a much larger number of possible operating states. Indeed, if N outages are considered for a given snapshot and there are M potential responses of the system (of which only one is optimum and the rest are associated to malfunctions) then there are N x M possible states that need to be analysed. This is computationally demanding if one considers that N is already of the order of hundreds and M can have the same order in a multi-busbar system. This becomes more constraining in planning timescales when one combines the N x M states with S operating conditions where S is also of the order of hundreds.

Furthermore, there is also a challenge related to the assumed PDF of demand curtailments of the potential operating states caused by malfunctions. In our 2-busbar model, for instance, we assumed a binary distribution where demand can be shed at two different levels (i.e. optimum and non-optimum) at a certain set of probabilities. However, even when making this simple assumption there are difficulties in determining the right value of the probability vector and of the non-optimum loadshed amount. In Chapter 3, this problem was addressed through an array of sensitivities that examined extreme events (e.g. 40 times the amount of optimum demand shed at a probability of 100%).

Both optimisation and data modelling have to be studied further in order to include the effects of the degree of reliability of smart grid technology in the T+O+X model.

6.2.1.2 Multi-stage and multi-period stochastic optimisation

In light of the increased amounts of generation reserves because of wind uncertainty and the increased presence of demand response that has to be reconnected after a certain time from being curtailed, there is a need to couple the operational with the planning timescales through time constrains. With such an improved large-scale T+O+X model we could, for example, analyse how different types of generation reserves that are scheduled to cover wind uncertainty in different timeframes can be shared to also cover transmission outages and hence ultimately increase network utilisation as well as decrease network investments.

The concatenation of various synchronous snapshots coupled through inter-temporal constraints together with the consideration of several generation and network outages have been addressed before [64,65], but only over a very limited time horizon (e.g. 24 hours) and with the sole intention of studying the scheduling of generation reserves. Multi-stage models for generation reserves, especially in the presence of wind, require a large scenario tree to represent the multiple stages of the systems along a time window. The implementation of such models are already challenging even on a single busbar [69].

6.2.1.3 Distributed computing

A major barrier for enhancing probabilistic models of the type considered in this work, is its ultimate execution time. In the current version of the model, we managed to reduce computational times and burden through several techniques, being the parallelisation of the Benders algorithm in a multi-core computer one of them. In our calculations, the number of parallel processes was limited by the numbers of cores of the computer utilised, which could be improved in the future when access to number of computers increases[26]. In this context, Cloud Computing is auspicious and can play a key role in optimising extremely large optimisation problems [77]. This fact becomes more relevant if one considers that commercial optimisers (like FICO Xpress) have special libraries already incorporated (mmjobs in the case of FICO) that can manage algorithms through distributed computing.

Amongst all proposed future tasks, this seems to be the easiest one (subject to hardware and software availability) and perhaps the one with the largest benefit associated.

6.2.1.4 Losses

So far, losses have been only included as an ex-post calculation when the results from the T+O+X were already obtained. However, it is suggested that future versions of the model should include losses in its objective function since these can impede the raise of potentially costly amounts of transfers. The difficulty of including losses is that these have to be approximated by a number of piecewise functions (one per line). Furthermore, the number of additional variables will be proportional to the number of lines and hence the optimisation will become more sensitive to the network size. Although, losses have been included in numerous planning tools [78,79], the already large size of our probabilistic formulation will make this task especially difficult.

6.2.1.5 Non-correlated wind

In all our studies, wind is assumed to be 100% correlated across the country. Multi-area wind is envisaged to create different degrees of stress in the transmission network that may lead to higher congestion costs and transmission investments. The combinatorial problem generated by the realisation of various wind profiles in several areas can be, however, computationally demanding and therefore difficult to handle. To tackle this issue within the already large-scale optimisation, one will

[26] Computers have to be available and coordinated by a master unit that allows the execution of the Benders algorithm. Also, software licences have to be available for all computers.

probably need to firstly enhance the current model by implementing distributed computing techniques and Monte Carlo sampling methods. It is also suggested to implement a snapshots-selection technique, similar to the already implemented contingencies-selection module, in order to eliminate further redundant input data.

6.2.1.6 Risk aversion

The objective functions considered in our model are risk neutral. Rather than optimising the expected unsupplied demand (cost or volume), it is suggested for further work to explore the option of optimising one of the tails of the PDF of demand curtailments too. By doing so, the most catastrophic events and their impacts can be explicitly incorporated. Techniques based on Conditional Value-at-Risk (CVaR) optimisation can be especially useful in the context of linear optimisation [80].

6.2.2 Market design for probabilistic network standards

The incentives framework and potentially market design may need to be modified in order to enable network operators to apply, in a realistic environment, the proposed probabilistic network standards.

6.3 Concluding remarks

This thesis developed (and derived the full mathematical formulation of) a fully integrated economic and reliability probabilistic approach for network operation and expansion in system with high penetration of wind. It has been shown that power transfers can be efficiently secured by a number of coordinated pre- and post-fault actions from the generation, transmission and demand side. The application of the probabilistic cost-benefit approach to a number of examples suggests that the network capacity that can be optimally released to users changes depending on actual system conditions. These include: level of constraints cost (that, in turn, can be changed by the levels of wind output that vary significantly); weather conditions (that are also naturally changing); volumes and costs of generation reserves; and costs of corrective demand actions (that may be voluntary and involuntary).

Our studies show that any attempt to fix a single generic value for maximum network utilisation, as in the present standards, will lead to inefficiencies, limiting the amount of capacity that can be released to network users, particularly during fair weather conditions. Furthermore, it was found that the deterministic framework is not necessarily more secure and, in effect, this can drive major risks in system network operation and incorrect network designs. We show that these problems can be addressed by adopting a probabilistic approach for network security. For the particular case of the UK, for instance, we found that the application of the proposed probabilistic standards will drive cost savings, in terms of investment in proposed network, reinforcements, level of transmission constraints and CO_2 performance of the system by reducing wind curtailments.

We pose the recognition that there are a number of concerns regarding the computational tools needed for probabilistic analysis. In this context, we developed a methodology that can be successfully applied over a fairly large equivalent representation of a transmission network and over a comprehensive set of contingent events[27]. The formulation is translated into a computational optimisation model, namely T+O+X, that is capable to internalise the capability of the computer utilised (i.e. number of cores as input data) so as to parallelise processes and therefore run in reduced times.

In addition to the advances in mathematical modelling, changes in incentives frameworks and market design may be needed for practical implementation of probabilistic standards.

Overall, we demonstrated that a probabilistic approach provides a consistent cost-benefit based framework for the development of future network operation and design standards. It provides the basis for the evaluation of the network capacity that can be released to network users in real time and that can be enhanced when newcomers connect. It enables the costs involved in network investment to be balanced against system operation and against the benefits that the released network capacity delivers to network users. Through risk based approaches, economic efficiency in maintaining security of supply can be achieved.

[27] The ENSG commission justifies their proposed GB network enhancements based on a system of 7 nodes and 6 branches [75]. The National Grid deterministic security model tries 81 main outages.

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Appendix A: Reliability formulas

This appendix describes the basic mathematical formulas used in reliability assessment and in this thesis.

Definitions:

$$P = 1 - e^{-\lambda T} \qquad \text{Eq. A.1}$$

$$U = \frac{\lambda}{\lambda + \mu} = \frac{r}{m + r} = \frac{r}{Ct} = \frac{f}{\mu} = \frac{\sum[downtime]}{\sum[uptime]} \qquad \text{Eq. A.2}$$

$$ORR = \frac{\lambda}{\lambda + \mu} - \frac{\lambda}{\lambda + \mu} e^{-(\lambda + \mu)T} \qquad \text{Eq. A.3}$$

Where:

P = probability of outage of a unit (transition from ON to OFF) within the lead time T.

U = unavailability or Forced Outage Rate (FOR). It represents the probability of finding the unit on forced outage at a distant time in the future.

ORR = Outage Rate Replacement. It represents the probability of finding a unit failed and not replaced during the lead time T.

λ = expected failure rate

μ = expected repair rate

m = mean time to failure = MTTF = $1 / \lambda$

m + r = mean time between failures = MTBF = $1 / f$

f = cycle frequency = $1 / Ct$

Ct = cycle time

T = Lead time

Eq. A.1, A.2 and A.3 are closely related:

- The expression Eq. A.3 is equivalent to Eq. A.2 when $T \rightarrow \infty$.
- The expression Eq. A.3 is equivalent to Eq. A.1 if $\mu = 0$.

Failures or forced outages can be divided into two categories according to their durations: permanent and transient. Each of them can have its own failure and repair rates.

For example, the expected failure rates of line 3 of the network shown in Table 4.8 according to [70] are 0.51 and 2.9 occurrences per year (occ/yr) for permanent and transient outages. They result in a probability of outage equal to 1.9 x 10^{-4} as indicated below.

$$P = 1 - e^{-0.5\frac{0.51+2.9}{8760}} \cong 0.5\frac{0.51+2.9}{8760} = 1.9\times 10^{-4} \qquad \text{Eq. A.4}$$

<u>*Model assumptions and simplifications:*</u>

The model developed in this thesis considers that the system operating point is dramatically changed after an outage occurs, which allows network operators to reconnect demand that was shed in a time period that is independent of the repair time of the component outaged. For example, demand shed can be reconnected within the next 30 minutes after the associated outage occurs while the failed component will be replaced in a month time. Reconnection times higher than 30minutes can be included in the model by an adjusted VoLL according to Eq. A.4.

$$VoLL^{*} = \frac{k}{30}\cdot VoLL \qquad \text{Eq. A.4}$$

Where k is the time taken (in minutes) to reconnect the demand that was shed because of the outage.

Large values of repair times (of permanent outages) may have an effect on the cost of constraints and also on the levels of reliability since less network assets are available during the operation. Therefore, the time associated with the unavailability produced by forced outages (*U*) is added to the planned outage time of the component in order to reflect the aforementioned effect in the model. For the sake of simplicity, network maintenance times are increased only if the value of the unavailability (in days) associated to permanent outages is higher than or equal to a day time. For example, the time period originally considered for the maintenance of the aforementioned line 3 (i.e. zero) is not increased since the unavailability related to its permanent outages is lower than a day (according to [70], 10 hours x 0.51 occ/yr < 24 hours).

Appendix B: Operational cost error

When ‘a’ is the set of relevant or umbrella operating states and ‘A’ is the set of all operating states it can be shown that:

$$\mathrm{OX}(\mathrm{A}\,,\,\mathrm{A}) - \mathrm{OX}(\mathrm{a}\,,\,\mathrm{a}) \leq \mathrm{OX}(\mathrm{A} \setminus \mathrm{a}\,,\,\mathrm{a}) \qquad \text{Eq. B.1}$$

Where:

Operational cost error = OX(A , A) – OX(a , a).

Aggregated risk of remaining outages = OX(A \ a , a).

OX(E , D) = sum of the (expected) operational costs of the states in set E over an optimum pre-fault dispatch that minimises O+X by considering the states in set D. In mathematical terms:

$$\mathrm{OX}(\mathrm{E}\,,\mathrm{D}) = C_0\left(\overrightarrow{x_0}^{*D}, \overrightarrow{u_0}^{*D}\right) + \sum_{j \epsilon E \wedge j \neq 0} p_j C_j\left(\overrightarrow{x_j}^{*E}, \overrightarrow{u_0}^{*D}, \overrightarrow{u_j}^{*E}\right) \qquad \text{Eq. B.2}$$

Where:

C_0 = Operational cost function of the intact system (C_0 = 0 if the intact system ∉ set E).

C_j = Operational cost function of outage j.

p_j = Probability of outage j.

$\overrightarrow{x_0}, \overrightarrow{u_0}$ = Vectors of state and control variables in the intact system of the O+X optimisation described through Eq. 2.10 to Eq. 2.17.

$\overrightarrow{x_j}, \overrightarrow{u_j}$ = Vectors of state and control variables in outage j of the O+X optimisation described through Eq. 2.10 to Eq. 2.17.

$\overrightarrow{x_0}^{*D}, \overrightarrow{u_0}^{*D}$ = Arguments of the minimum of the O+X optimisation solved over k ∈ set D. Set D does always include the intact system.

$\overrightarrow{x_J}^{*E}, \overrightarrow{u_J}^{*E}$ = Arguments of the minimum of the O+X optimisation solved over k ∈ set E, and when considering $\overrightarrow{x_0} = \overrightarrow{x_0}^{*D}$ and $\overrightarrow{u_0} = \overrightarrow{u_0}^{*D}$. Set E may (or may not) include the intact system.

Proof:

The value of the full operational cost/risk function (that sums the costs and risks associated to all operating states in set A) can be minimised only if all potential operating states are included in the optimisation. In other words, if an attempt is made to optimise the overall costs and risks in a given operating condition by considering only a subset of A (namely a), a suboptimal solution of the original problem is obtained. In mathematical terms:

$$\mathrm{OX}(\mathrm{A}, \mathrm{A}) \leq \mathrm{OX}(\mathrm{A}, \mathrm{a}) \qquad \text{Eq. B.3}$$

For an already optimised O+X cost function where the outages in set were considered, its resulted value can be split according to Eq. B.4.

$$\mathrm{OX}(\mathrm{A}, \mathrm{a}) = \mathrm{OX}(\mathrm{A} \setminus \mathrm{a}, \mathrm{a}) + \mathrm{OX}(\mathrm{a}, \mathrm{a}) \qquad \text{Eq. B.4}$$

By equating Eq. B.3 and Eq. B.4, Eq. B.1 can be obtained. ■

The algorithm to find the set of umbrella outages (set a) should consider a low tolerance value (chosen by the user) with the intention of limiting the maximum value of OX(A \ a , a). The proof above demonstrates that the prescribed tolerance constrains the error incurred in the value of the full objective function too.

Appendix C: Model validation by comparison

The small-scale network study presented in this appendix intends to validate the model and analyse its fundamental features.

Validation:

The results of the operational module are compared with the ones obtained by a previously developed stochastic OPF formulation presented in [65]. A 3-node network also introduced in [65] is utilised in our assessments below. In Figure C.1 and Table C.1 the basic diagram and data of this small-scale network is presented.

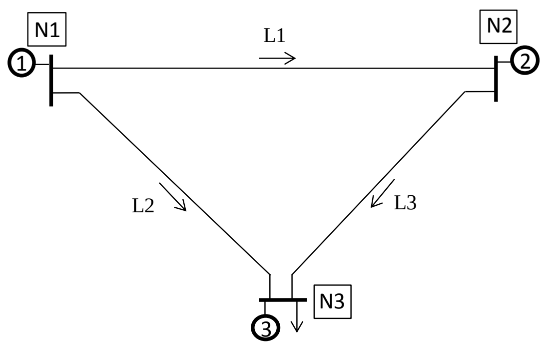

Figure C.1: Bouffard's 3-node example

Table C.1: Main generation input data

ID	Node	Capacity [MW]	Minimum generation [MW]	Ramp up/down [MW]	Fuel price [£/MWh]
1	1	100	10	100	30
2	2	100	10	100	40
3	3	50	10	50	20

In addition and as in Bouffard's example, demand is only placed in node 3 and is equal to 30, 80, 110 and 40 MW across the four periods studied: t1, t2, t3 and t4, respectively. The capacities of all circuits are assumed to be 55 MW during pre- and post-fault conditions. Also, the VoLL was assumed to be the same at all times and equal to 1k£/MWh. All N-1 and N-2 generation outages were included together with all N-1 transmission outages and their combinations, i.e. 27 outages plus intact system state.

An important difference between Bouffard's model and the one developed in this thesis is that the former is gross pool based while the latter is net pool based. Therefore, the simulations use:

- the same fuel prices as Bouffard;
- fuel prices for the unconstrained generation commitments;
- offer and reserve up prices equal to Bouffard's reserve up prices (i.e. 5, 7 and 8 £/MWh for generator 1 (G1), 2 (G2) and 3 (G3), respectively);
- bid and reserve down prices equal to 1.75, 2 and 1.5 £/MWh for G1, G2 and G3, respectively, following an identical merit order given by the fuel prices;
- reserve availability price equal to 0.1 £/MW/h.

With the aforementioned input data, the pre- and post- fault dispatches resulted to be the same as the ones obtained by Bouffard for the four periods analysed when considering no participation of non-standing reserve (results of Table X in [65]). Results are also shown in this appendix in Table C.2.

Table C.2: Comparison of Bouffard's results (same as in Table X in [65]) with our model's results – left/right respectively

	Time [h]			
	1	2	3	4
Generation [MW]	0/0	30/30	50/50	10/10
Max reserve up [MW]	0/0	50/50	10/10	30/30
Max reserve down [MW]	0/0	0/0	5/5	0/0
Generation [MW]	0/0	0/0	10/10	0/0
Max reserve up [MW]	0/0	0/0	45/45	0/0
Max reserve down [MW]	0/0	0/0	0/0	0/0
Generation [MW]	30/30	50/50	50/50	30/30
Max reserve up [MW]	0/0	0/0	0/0	0/0
Max reserve down [MW]	0/0	0/0	0/0	0/0

Where maximum values of reserve up and down services were obtained over the N-1 outages only.[28]

Optimum cost balance of pre- and post-fault actions in the peak demand condition:

The dispatches for each N-1 contingency that justify the results shown in Table C.2 during the peak demand condition, i.e. t3, are shown in Figure C.2.

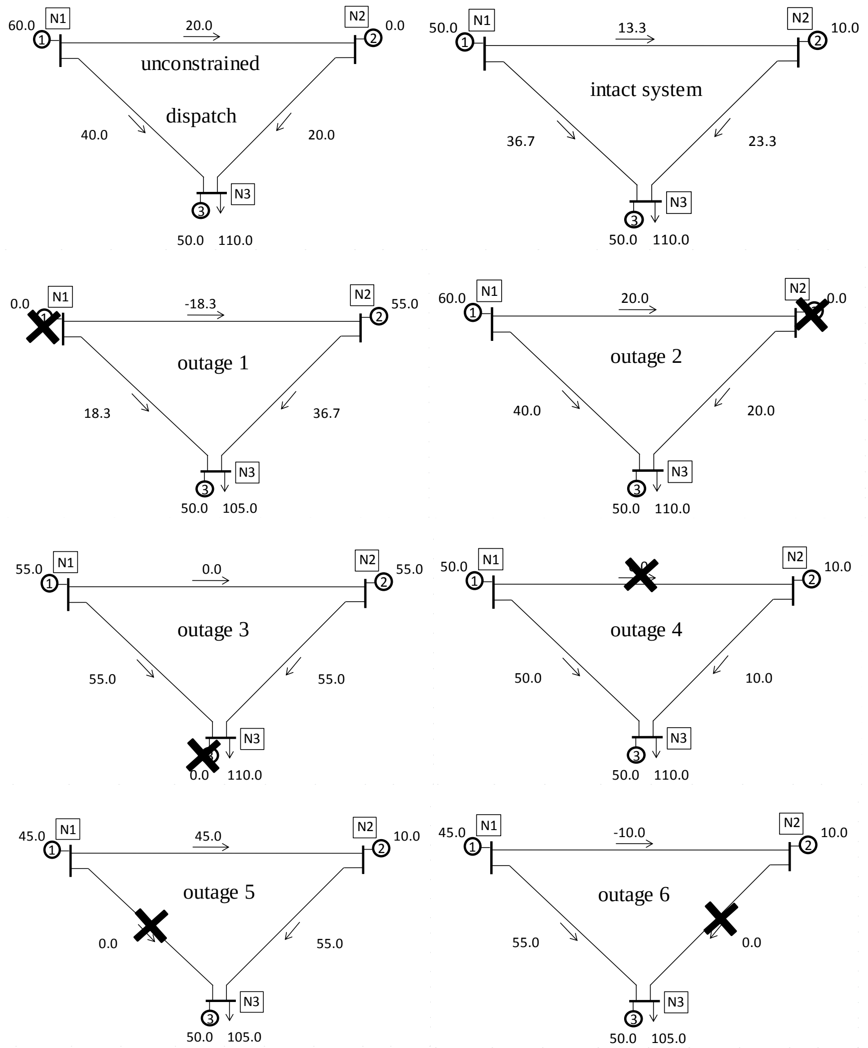

Figure C.2: Unconstrained dispatch and all operating states' dispatches in t3

The unconstrained dispatch simply represents the economic dispatch result when transmission and security are not considered. Then, the model balances generation to comply with the probabilistic level of security derived by the formulation and thus G2 is also committed at a minimum level in the intact system. This action is balanced by constraining off G1 by 10 MW. Also, G1 and G2 hold 10 and 45 MW of reserve up.

[28] Because [65] does not consider outages beyond N-1.

Regarding the post-fault actions for the N-1 outages, G1's reserve up is utilised to cover outage 2 and 3, and its reserve down is utilized to cover outage 5 and 6. G2's reserve up is utilised to cope with outage 1 and 3. It is also important to notice that demand side actions are used to balance the system under outage 1, 5 and 6 while SPS to generation are not exercised. Outage 4 presents no post-fault actions.

These N-1 failures together with the rest of the outages (e.g. N-2 in generation, and N-2 and N-3 in combined generation and transmission) are included in the full cost breakdown shown in Table C.3.

Table C.3: Breakdown of transmission costs during t3 when considering all outages

Cost of [£/30mins]				
Constraints	Reserve holding	Reserve utilization	ENS	Total
26.25	2.75	0.81	5.48	35.29

The total cost does not include the initial generators' commitments, taking account of only the net balances of generation.

The cost of the Energy Not Supplied (ENS) is limited to 5.48 £/30min by incurring in a cost of constraints of 26.25 £/30min (caused by constraining on 10 MW at a price of 7 £/MWh and off 10 MW at a price of 1.7 £/MWh for 30 minutes) and other post-fault costs of 3.56 £/30min (caused by holding 55 MW of reserve at a price of 0.1 £/MW/h for 30 minutes and exercising it at a expected cost of 0.81 £/30min), which are all optimally balanced by the model.

Appendix D: Deterministic dispatch with preventive control

The deterministic version of the proposed probabilistic model corresponds to an optimisation equal to the proposed one (in both operation and planning) but that considers: only N-1 outages in generation and transmission; all N-D outages in transmission (i.e. double circuit outages); all state probabilities equal to 1; price of generation-based corrective actions approaching zero; and price of demand shedding approaching infinity. In other words, the deterministic version balances only the costs of transmission constraints and investment for a given reliability profile (i.e. N-D).

The use of generation reserves to deal only with generation outages is also constrained and not with the ones derived from transmission failures. In mathematical terms, Eq. 4.10 and Eq. 4.11 are replaced by Eq. D.1, Eq. D.2, Eq. D.3 and Eq. D.4.

$$resuu_g^c \le resh_g \quad \forall c, g \text{ with c associated to generation outages} \qquad \text{Eq. D.1}$$

$$resud_g^c \le \Delta \mathrm{resd}_g \quad \forall c, g \text{ with c associated to generation outages} \qquad \text{Eq. D.2}$$

$$resuu_g^c \le 0 \quad \forall c, g \text{ with c associated to line outages} \qquad \text{Eq. D.3}$$

$$resud_g^c \le 0 \quad \forall c, g \text{ with c associated to line outages} \qquad \text{Eq. D.4}$$

This model corresponds to a SC-OPF with preventive control like the ones proposed in [59].

Appendix E: Detailed results on the GB system

All the results shown in this appendix should be taken in the context of a number of simplifying assumptions which were made to obtain reasonable enhancements over the England-Scotland interconnector only.

The network investments derived by the deterministic and probabilistic models are displayed in Table E.1 and Table E.2.

Table E.1: T+O+X investments over the entire GB system -1/2

From-To	Area	Initial capacity [MW]	2020 capacity [MW]		Network enhancement [MW]		Cost of investment [mill£/year]		Asset utilisaton [%]	
			Probabilistic	Deterministic	Probabilistic	Deterministic	Probabilistic	Deterministic	Probabilistic	Deterministic
1-2	Scotland	425	2425	2925	2000	2500	10.0	12.5	28%	24%
1-3	Scotland	85	1085	2585	1000	2500	2.5	6.3	28%	10%
1-2	Scotland	425	2425	2925	2000	2500	10.0	12.5	28%	24%
1-3	Scotland	85	1085	2585	1000	2500	2.5	6.3	28%	10%
2-4	Scotland	680	2180	1680	1500	1000	7.5	5.0	40%	38%
2-4	Scotland	680	2180	1680	1500	1000	7.5	5.0	40%	38%
4-7	Scotland	935	1435	1435	500	500	0.6	0.6	28%	20%
4-6	Scotland	1275	1275	1275	0	0	0.0	0.0	42%	35%
4-6	Scotland	935	935	935	0	0	0.0	0.0	58%	48%
4-5	Scotland	850	1350	1350	500	500	0.6	0.6	40%	34%
4-5	Scotland	850	1350	1350	500	500	0.6	0.6	40%	34%
4-7	Scotland	935	1435	1435	500	500	0.6	0.6	28%	20%
5-6	Scotland	1190	1190	1190	0	0	0.0	0.0	9%	10%
5-6	Scotland	1190	1190	1190	0	0	0.0	0.0	6%	6%
6-9	England-Scotland	1190	1870	1870	680	680	3.4	3.4	39%	33%
6-9	England-Scotland	1190	1870	1870	680	680	3.4	3.4	39%	33%
7-8	England-Scotland	1190	1870	1870	680	680	0.9	0.9	49%	40%
7-8	England-Scotland	1190	1870	1870	680	680	0.9	0.9	49%	40%
7-6	Scotland	850	850	850	0	0	0.0	0.0	4%	4%
7-6	Scotland	850	850	850	0	0	0.0	0.0	4%	4%
8-10	England-Scotland	1190	1870	1870	680	680	1.7	1.7	47%	38%
8-10	England-Scotland	1190	1870	1870	680	680	1.7	1.7	47%	38%
9-11	England	1190	1690	2690	500	1500	2.5	7.5	35%	21%
9-11	England	1190	1690	2690	500	1500	2.5	7.5	35%	21%
9-10	England	765	765	1265	0	500	0.0	1.3	19%	10%
9-10	England	680	680	1180	0	500	0.0	1.3	16%	8%
10-15	England	4080	4080	4080	0	0	0.0	0.0	35%	37%
10-15	England	3400	3400	3400	0	0	0.0	0.0	55%	58%
11-15	England	2125	2125	2125	0	0	0.0	0.0	4%	3%
11-15	England	2125	2125	2125	0	0	0.0	0.0	4%	3%
11-13	England	1870	1870	2370	0	500	0.0	1.3	70%	54%
11-13	England	1870	1870	2370	0	500	0.0	1.3	70%	54%
11-12	England	2805	2805	2805	0	0	0.0	0.0	9%	9%
11-12	England	2805	2805	2805	0	0	0.0	0.0	9%	9%
12-13	England	2635	2635	2635	0	0	0.0	0.0	16%	15%
12-18	England	2040	2040	2040	0	0	0.0	0.0	68%	67%
12-18	England	2040	2040	2040	0	0	0.0	0.0	68%	67%
12-13	England	2635	2635	2635	0	0	0.0	0.0	16%	15%
13-18	England	2040	2040	2040	0	0	0.0	0.0	56%	55%
13-18	England	2040	2040	2040	0	0	0.0	0.0	56%	55%
13-15	England	1020	1020	1020	0	0	0.0	0.0	15%	16%
13-15	England	850	850	850	0	0	0.0	0.0	18%	19%
13-14	England	850	850	850	0	0	0.0	0.0	20%	22%
13-14	England	850	850	850	0	0	0.0	0.0	19%	21%
14-16	England	2210	2210	2210	0	0	0.0	0.0	5%	5%
14-16	England	510	510	510	0	0	0.0	0.0	21%	19%
15-16	England	2380	2380	2380	0	0	0.0	0.0	10%	8%
15-16	England	4675	4675	4675	0	0	0.0	0.0	15%	13%
15-14	England	4250	4250	4250	0	0	0.0	0.0	17%	18%
15-14	England	4250	4250	4250	0	0	0.0	0.0	17%	18%
16-19	England	2380	2380	2380	0	0	0.0	0.0	25%	25%

Table E.2: T+O+X investments over the entire GB system -2/2

From-To	Area	Initial capacity [MW]	2020 capacity [MW]		Network enhancement		Cost of investment		Asset utilisaton [%]	
			Probabilistic	Deterministic	Probabilistic	Deterministic	Probabilistic	Deterministic	Probabilistic	Deterministic
16-19	England	3230	3230	3230	0	0	0.0	0.0	18%	19%
17-16	England	1870	1870	1870	0	0	0.0	0.0	54%	56%
17-16	England	1615	1615	1615	0	0	0.0	0.0	63%	65%
17-22	England	1785	1785	1785	0	0	0.0	0.0	30%	29%
17-22	England	1785	1785	1785	0	0	0.0	0.0	30%	29%
18-17	England	2635	2635	2635	0	0	0.0	0.0	9%	9%
18-17	England	2975	2975	2975	0	0	0.0	0.0	8%	8%
18-23	England	1700	1700	1700	0	0	0.0	0.0	41%	41%
18-23	England	1700	1700	1700	0	0	0.0	0.0	41%	41%
20-26	England	2380	2380	2380	0	0	0.0	0.0	36%	36%
20-26	England	2380	2380	2380	0	0	0.0	0.0	36%	36%
20-19	England	1360	1360	1360	0	0	0.0	0.0	24%	25%
20-19	England	1360	1360	1360	0	0	0.0	0.0	36%	37%
21-16	England	2380	2380	2380	0	0	0.0	0.0	33%	34%
21-16	England	2380	2380	2380	0	0	0.0	0.0	33%	34%
21-25	England	2380	2380	2380	0	0	0.0	0.0	29%	29%
21-25	England	2380	2380	2380	0	0	0.0	0.0	29%	29%
21-20	England	2380	2380	2380	0	0	0.0	0.0	9%	9%
21-20	England	2380	2380	2380	0	0	0.0	0.0	9%	9%
21-19	England	2550	2550	2550	0	0	0.0	0.0	40%	41%
21-19	England	2380	2380	2380	0	0	0.0	0.0	43%	44%
22-16	England	1700	1700	1700	0	0	0.0	0.0	55%	56%
22-16	England	1700	1700	1700	0	0	0.0	0.0	55%	56%
22-25	England	2805	2805	2805	0	0	0.0	0.0	46%	46%
22-25	England	2805	2805	2805	0	0	0.0	0.0	46%	46%
22-21	England	2380	2380	2380	0	0	0.0	0.0	61%	63%
22-21	England	2380	2380	2380	0	0	0.0	0.0	11%	11%
23-29	England	1700	1700	1700	0	0	0.0	0.0	16%	16%
23-24	England	2380	2380	2380	0	0	0.0	0.0	48%	48%
23-24	England	3740	3740	3740	0	0	0.0	0.0	35%	35%
23-22	England	2380	2380	2380	0	0	0.0	0.0	24%	25%
23-22	England	2380	2380	2380	0	0	0.0	0.0	24%	25%
23-29	England	1700	1700	1700	0	0	0.0	0.0	16%	16%
24-28	England	1870	1870	1870	0	0	0.0	0.0	24%	24%
24-25	England	1190	1190	1190	0	0	0.0	0.0	24%	24%
24-25	England	1190	1190	1190	0	0	0.0	0.0	24%	24%
24-28	England	1870	1870	1870	0	0	0.0	0.0	24%	24%
25-26	England	5950	5950	5950	0	0	0.0	0.0	12%	12%
25-26	England	4675	4675	4675	0	0	0.0	0.0	15%	15%
27-26	England	2635	2635	2635	0	0	0.0	0.0	11%	11%
27-26	England	2635	2635	2635	0	0	0.0	0.0	11%	11%
28-27	England	2635	2635	2635	0	0	0.0	0.0	16%	17%
28-27	England	2635	2635	2635	0	0	0.0	0.0	16%	17%
29-28	England	2380	2380	2380	0	0	0.0	0.0	5%	6%
29-28	England	2380	2380	2380	0	0	0.0	0.0	5%	6%
3-4	Scotland	510	1510	2010	1000	1500	2.5	3.8	37%	22%
3-4	Scotland	510	1510	2010	1000	1500	2.5	3.8	37%	22%
3-2	Scotland	595	1095	1095	500	500	2.5	2.5	40%	28%
5-12	England-Scotland	0	2000	2000	2000	2000	77.8	77.8	40%	34%
2-10	England-Scotland	0	0	2000	0	2000	0.0	77.8	0%	37%

The yearly generation production of the deterministic and probabilistic solutions together with the volumes of offers and bids accepted per technology and area are shown in Table E.3 and E.4.

Table E.3: Yearly generation, offers and bids accepted per technology and per area - deterministic

Scotland

Technology	Generation [TWh]	Offers [TWh]	Bids [TWh]	Load factor [%]
Wind	37.10	0.00	1.15	29%
Hydro	0.00	0.00	0.00	0%
PS	0.00	0.00	0.00	0%
CHP	1.88	0.00	0.00	69%
CCGT	10.74	0.07	1.51	81%
Peaker	0.00	0.00	0.00	0%
Coal	9.19	0.13	0.31	33%
Nuclear	10.48	0.00	0.00	55%
Total	69.39	0.19	2.97	

Demand [MW]	33.62
Export [MW]	35.77

England

Technology	Generation [TWh]	Offers [TWh]	Bids [TWh]	Load factor [%]
Wind	14.46	0.00	0.00	30%
Hydro	0.00	0.00	0.00	0%
PS	0.00	0.00	0.00	0%
CHP	12.11	0.00	0.00	69%
CCGT	188.06	9.49	6.90	77%
Peaker	0.00	0.00	0.00	0%
Coal	7.55	0.66	0.47	3%
Nuclear	63.80	0.00	0.00	86%
Total	285.99	10.15	7.37	

Demand [MW]	321.75
Import [MW]	35.77

UK

Technology	Generation [TWh]	Offers [TWh]	Bids [TWh]	Load factor [%]
Wind	51.56	0.00	1.15	29%
Hydro	0.00	0.00	0.00	0%
PS	0.00	0.00	0.00	0%
CHP	13.99	0.00	0.00	69%
CCGT	198.81	9.56	8.41	77%
Peaker	0.00	0.00	0.00	0%
Coal	16.74	0.78	0.77	7%
Nuclear	74.28	0.00	0.00	79%
Total	355.38	10.34	10.34	

Demand [MW]	355.38

Table E.4: Yearly generation, offers and bids accepted per technology and per area - probabilistic

Scotland

Technology	Generation [TWh]	Offers [TWh]	Bids [TWh]	Load factor [%]
Wind	37.45	0.00	0.81	29%
Hydro	0.00	0.00	0.00	0%
PS	0.00	0.00	0.00	0%
CHP	1.88	0.00	0.00	69%
CCGT	9.90	0.06	2.34	75%
Peaker	0.00	0.00	0.00	0%
Coal	8.54	0.00	0.84	31%
Nuclear	10.48	0.00	0.00	55%
Total	68.25	0.06	3.98	

Demand [MW]	33.62
Export [MW]	34.62

England

Technology	Generation [TWh]	Offers [TWh]	Bids [TWh]	Load factor [%]
Wind	14.46	0.00	0.00	30%
Hydro	0.00	0.00	0.00	0%
PS	0.00	0.00	0.00	0%
CHP	12.11	0.00	0.00	69%
CCGT	188.50	8.22	5.19	77%
Peaker	0.00	0.00	0.00	0%
Coal	8.26	0.92	0.02	4%
Nuclear	63.80	0.00	0.00	86%
Total	287.13	9.14	5.22	

Demand [MW]	321.75
Import [MW]	34.62

UK

Technology	Generation [TWh]	Offers [TWh]	Bids [TWh]	Load factor [%]
Wind	51.90	0.00	0.81	30%
Hydro	0.00	0.00	0.00	0%
PS	0.00	0.00	0.00	0%
CHP	13.99	0.00	0.00	69%
CCGT	198.40	8.27	7.53	77%
Peaker	0.00	0.00	0.00	0%
Coal	16.80	0.92	0.86	7%
Nuclear	74.28	0.00	0.00	79%
Total	355.38	9.20	9.20	

Demand [MW]	355.38

When analysing a single operating condition with optimum network investment, the results of the deterministic and the probabilistic optimisations are depicted in Table E.5, Table E.6, Table E.7 and Table E.8.

Table E.5: Generation and demand statistics per node during peak demand and 95% of wind availability - deterministic

Node	Generation [MW]	Offers [MW]	Bids [MW]	Reserve [MW]	Demand [MW]
1	5662	0	1463	0	500
2	853	0	1091	184	600
3	1425	0	0	0	600
4	535	0	1929	18	1400
5	20	20	0	0	500
6	3800	0	0	0	1300
7	2150	0	840	0	800
8	0	0	0	0	100
9	0	0	0	0	100
10	2767	0	740	400	2800
11	5500	0	200	0	3700
12	3200	0	0	0	1300
13	0	0	0	0	2700
14	0	0	0	0	2000
15	1654	1654	0	402	2900
16	8535	0	0	0	1700
17	2000	2000	0	0	1200
18	2000	2000	0	0	5800
19	4425	0	0	0	2200
20	1200	0	0	0	1100
21	500	0	0	0	800
22	500	0	0	0	2000
23	5156	156	0	39	5200
24	0	0	0	0	1500
25	2000	0	0	0	10700
26	3000	0	0	0	1500
27	1425	0	0	0	500
28	1500	120	0	0	3000
29	1493	313	0	157	2800
Total	61300	6263	6263	1200	61300

Table E.6: Generation results per area and per technology during peak demand and 95% of wind availability - deterministic

Scotland

Technology	Generation [MW]	Offers [MW]	Bids [MW]	Reserve [MW]	Load factor [%]
Wind	12360	0	1463	0	85%
Hydro	0	0	0	0	0%
PS	0	0	0	0	0%
CHP	226	0	0	0	73%
CCGT	388	20	1091	184	26%
Peaker	0	0	0	0	0%
Coal	271	0	2769	18	8%
Nuclear	1200	0	0	0	55%
Interconnector	0	0	0	0	0%
Total	14446	20	5322	202	

Demand [MW]	5800
Export [MW]	8646

England

Technology	Generation [MW]	Offers [MW]	Bids [MW]	Reserve [MW]	Load factor [%]
Wind	5225	0	0	0	95%
Hydro	0	0	0	0	0%
PS	0	0	0	0	0%
CHP	1460	0	0	0	73%
CCGT	26880	433	433	557	96%
Peaker	0	0	0	0	0%
Coal	5809	5809	507	441	23%
Nuclear	7480	0	0	0	88%
Interconnector	0	0	0	0	0%
Total	46854	6243	940	998	

Demand [MW]	55500
Import [MW]	8646

UK

Technology	Generation [MW]	Offers [MW]	Bids [MW]	Reserve [MW]	Load factor [%]
Wind	17585	0	1463	0	88%
Hydro	0	0	0	0	0%
PS	0	0	0	0	0%
CHP	1686	0	0	0	73%
CCGT	27268	453	1524	741	92%
Peaker	0	0	0	0	0%
Coal	6081	5809	3276	459	21%
Nuclear	8680	0	0	0	81%
Interconnector	0	0	0	0	0%
Total	61300	6263	6263	1200	

Demand [MW]	61300

Table E.7: Generation and demand statistics per node during peak demand and 95% of wind availability - probabilistic

Node	Generation [MW]	Offers [MW]	Bids [MW]	Reserve [MW]	Demand [MW]
1	6859	0	266	0	500
2	485	0	1459	0	600
3	1271	0	154	0	600
4	264	0	2200	0	1400
5	20	20	0	0	500
6	3800	0	0	0	1300
7	2150	0	840	0	800
8	0	0	0	0	100
9	0	0	0	0	100
10	3507	0	0	0	2800
11	5700	0	0	0	3700
12	3200	0	0	0	1300
13	0	0	0	0	2700
14	0	0	0	0	2000
15	1311	1311	0	328	2900
16	10135	1600	0	400	1700
17	1299	1299	0	200	1200
18	689	689	0	172	5800
19	4425	0	0	0	2200
20	1200	0	0	0	1100
21	500	0	0	0	800
22	500	0	0	0	2000
23	5000	0	0	0	5200
24	0	0	0	0	1500
25	2000	0	0	0	10700
26	3000	0	0	0	1500
27	1425	0	0	0	500
28	1380	0	0	100	3000
29	1180	0	0	0	2800
Total	61300	4919	4919	1200	61300

Table E.8: Generation results per area and per technology during peak demand and 95% of wind availability - probabilistic

Scotland

Technology	Generation [MW]	Offers [MW]	Bids [MW]	Reserve [MW]	Load factor [%]
Wind	13403	0	420	0	92%
Hydro	0	0	0	0	0%
PS	0	0	0	0	0%
CHP	226	0	0	0	73%
CCGT	20	20	1459	0	1%
Peaker	0	0	0	0	0%
Coal	0	0	3040	0	0%
Nuclear	1200	0	0	0	55%
Interconnector	0	0	0	0	0%
Total	14849	20	4919	0	

Demand [MW]	5800
Export [MW]	9049

England

Technology	Generation [MW]	Offers [MW]	Bids [MW]	Reserve [MW]	Load factor [%]
Wind	5225	0	0	0	95%
Hydro	0	0	0	0	0%
PS	0	0	0	0	0%
CHP	1460	0	0	0	73%
CCGT	26880	0	0	100	96%
Peaker	0	0	0	0	0%
Coal	5406	4899	0	1100	21%
Nuclear	7480	0	0	0	88%
Interconnector	0	0	0	0	0%
Total	46451	4899	0	1200	

Demand [MW]	55500
Import [MW]	9049

UK

Technology	Generation [MW]	Offers [MW]	Bids [MW]	Reserve [MW]	Load factor [%]
Wind	18628	0	420	0	93%
Hydro	0	0	0	0	0%
PS	0	0	0	0	0%
CHP	1686	0	0	0	73%
CCGT	26900	20	1459	100	91%
Peaker	0	0	0	0	0%
Coal	5406	4899	3040	1100	19%
Nuclear	8680	0	0	0	81%
Interconnector	0	0	0	0	0%
Total	61300	4919	4919	1200	

Demand [MW]	61300