Integrated reliability and cost–benefit-based standards for transmission network operation

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Abstract: The growing interest in decarbonizing 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 1950s, may be inappropriate for the new emerging system as they may pose entry barriers for both renewable generation and Smart Grid technologies. In this context, the current paper 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 should 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 study demonstrates 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 suggest that the probabilistic approach provides the basis for the development of future network operation and design standards that would maximize the value of the transmission network to users, enhance the utilization of existing networks, foster the entrance of new technologies that may complement and provide alternative network reinforcement, and hence facilitate efficient integration of renewable generation.

Keywords: transmission network operation, transmission network reliability, cost–benefit analysis, probabilistic security standards

1 INTRODUCTION

Electricity systems worldwide face challenges of unprecedented proportions. In response to the climate change crisis, governments of a number of countries are already committed to the support of renewable and other low-carbon generation technologies. Delivering these targets cost effectively will require fundamental changes in the historical philosophy of network operation and considerable investment [**1**]. However, before the need for new network investment can be established, 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 time scales are efficient. For instance, for a given transmission asset, it is common to observe forced levels of underutilization with the intention of preserving sufficient margins for system

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security 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 question of the present analysis. 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 have been based on deterministic operation and design criteria whereby electricity 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. Historically, this practice has delivered a successful operation of massive and complex electric networks in the absence of advanced technology to monitor, predict, simulate, and control them in real time.

Recently, however, there have been significant debates associated with updates of network operation and planning standards and practices in a number of jurisdictions. This is driven by a variety of factors, including the following.

1. The need to incorporate non-conventional generation, such as wind power, which has exposed the inadequacies of the existing peak security-driven standards given the limited capacity value of wind generation.
2. The need to demonstrate that investment in monopoly functions is efficient and delivers the best value for consumers; that is, provides the right balance between the costs involved (paid by the users) and the benefits that users derive from it, including reliability improvements. (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. While 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 [**2**].)
3. The need to 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.
4. The need to consider the application of advanced communication and information technologies as part of the electricity grid infrastructure, combined with recent developments of Special Protection Schemes (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), and so on. These techniques can provide an efficient solution for the provision of network security and a lower level of network redundancy [**3–8**].

Given this new reality, it becomes necessary to determine the optimum level of power transfer that balances risks and benefits. This can be only considered within an appropriate probabilistic framework [**9–12**] since deterministic rules are barely a binary measurement of risk as highlighted in reference [**13**]. Furthermore, 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. (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.) In contrast, a standard that is established within a cost–benefit framework (probabilistic) is, in principle, superior over the historical deterministic approach, as it balances more accurately the reliability (and other) benefits against operation and investment costs incurred to deliver these benefits. Given the advances in reliability analysis techniques over the last 20 years, the evaluation of appropriate levels of security within a cost–benefit framework is now feasible.

In this context, the aim of the present work is twofold. First, this paper presents a framework for the development of probabilistic network operation criteria that incorporate various operational measures based on alternative Smart Grid concepts which allow generation, transmission, and demand corrective actions to be coordinated in both pre- and post-fault time windows. This is particularly relevant for systems with significant penetration of wind generation located in remote areas that would, under deterministic rules, require significant network reinforcements that can be partially substituted by a number of more cost-effective operational measures.

Second, the framework developed in this paper is illustrated on a case of future operation of the England–Scotland interconnector and this is used to

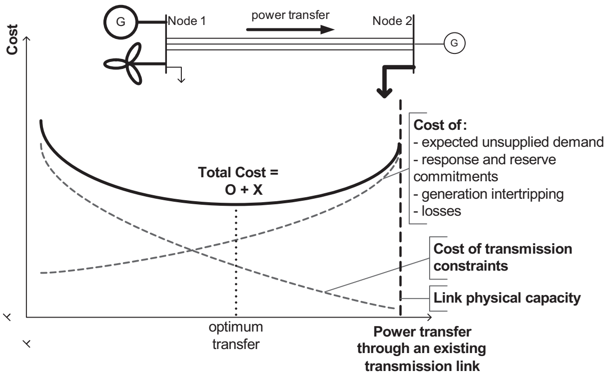

Fig. 1 Balance to determine optimum transfer in a single transmission link

assess its potential benefits together with addressing the current concerns regarding the present deterministic Security and Quality of Supply Standards (SQSS).

The paper is organized as follows. Section 2 describes the fundamental principles proposed. Section 3 presents the assessment of several case studies and the evidence that shows the inadequacies of the present security standards to deliver network efficiency. Section 4 summarizes the main conclusions and recommendations. The appendices detail the notation, model and data used.

2 OPTIMUM POWER TRANSFER: A PROBABILISTIC FRAMEWORK ADAPTED FOR NEW TECHNOLOGY

2.1 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 [**14**]. In this context, 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 reference [**15**]. Consequently, in this proposal, the efficient level of security of a given operating condition (a particular snapshot of demand across the interconnected system usually, it is assumed fixed in 30-min intervals) 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 measures such as SPS, DSM, etc., among others), and the expected unsupplied demand cost, *X*. Figure 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.

This equilibrium position is 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 the one observed under adverse weather (thunderstorms, high winds, ice, etc.) [**16**]. Hence, under fair weather conditions, given the lower probability of transmission line outages, system operators should make available to users larger amounts of network capacity than under adverse weather as shown in Fig. 2(a).

Similarly, the optimal power transfer may vary with system loading conditions and/or wind availability. Given that constraint costs, due to restricted power transfers, will be the highest when wind power is constrained, it may be more cost-effective

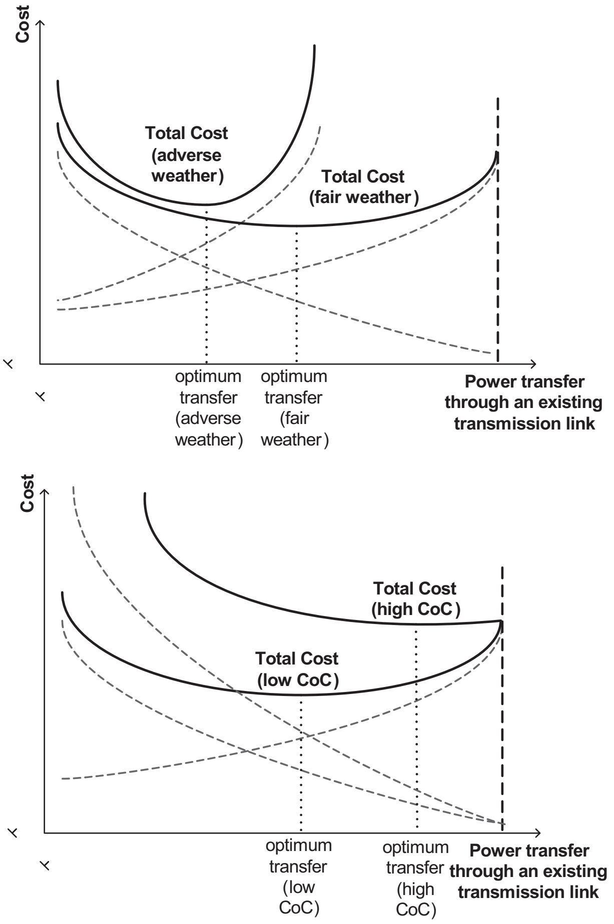

Fig. 2 Balance to determine the optimum transfer in a single transmission link under different weather conditions (a, top) and cost of constraints (CoC) levels (b, bottom)

to accept higher power transfers in such conditions as illustrated in Fig. 2(b).

There may be some correlation between weather conditions, wind generation outputs, and the overall physical transmission capacity, assuming that 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 transfer.

The optimum transfer can be affected by a number of other parameters such as constraint prices, Value of Lost Load (VoLL), response and reserve holding levels and their associated costs, cost of availability, and exercise of various operational actions, and so on. 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 the following.

(a) A comprehensive list of contingencies or operating states (beyond *N*–1 and *N*–2 types) in a probabilistic fashion in order to achieve global optimality. (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. The intact system is also an operating state.)

(b) The 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.

2.2 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 decrease and increase 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 generators' 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; for example, 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 the demand–supply balance (i.e. system frequency). Depending on how fast this spare generation capacity can react, different services are defined. In this paper, services related to the automatic very fast response from generation (on the order of seconds); that is, primary frequency response, and services related to the slower (on the order of minutes) centrally controlled generation reaction that is, synchronized 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 utilization 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 connects exporting and importing areas of the system, SPS automatically disconnect (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 the fact that all 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 minimize equation (1)

$$\min \left\{ \begin{array}{l} \sum\limits_{g=1,\ldots,Ng} \left\{ (\tau^{pf=1} + \tau^{pf=2}) \cdot (\pi off_g \cdot off_g^{c=1} - \pi bid_g \cdot bid_g^{c=1}) \right\} + \\ \sum\limits_{\substack{c=2,\ldots,M \\ g=1,\ldots,Ng}} \left\{ \rho^c \cdot \tau^{pf=2} \cdot (\pi off_g \cdot off_g^c - \pi bid_g \cdot bid_g^c) \right\} + \\ \sum\limits_{g=1,\ldots,Ng} \left\{ (\tau^{pf=1} + \tau^{pf=2}) \cdot (\pi rsp_g \cdot nrsp_g + \pi res_g \cdot nres_g) \right\} + \\ \sum\limits_{\substack{c=2,\ldots,M \\ n=A,B}} \left\{ \rho^c \cdot \pi itrp_n \cdot itrp_n^c \right\} + \sum\limits_{\substack{c=2,\ldots,M \\ pf=1,2 \\ n=A,B}} \left\{ \rho^c \cdot \tau^{pf} \cdot voll_n \cdot ll_n^{c,pf} \right\} \end{array} \right\} \tag{1}$$

For notation, see Appendix 1.

The five summations in the objective function respectively represent:

(a) the cost of transmission constraints in the intact system (i.e. before a fault occurs), which arises from offers and bids accepted ($off_g^{c=1}$; $bid_g^{c=1}$) that are charged regardless of outages occurring and for the entire time window ($\tau^{pf=1} + \tau^{pf=2}$);

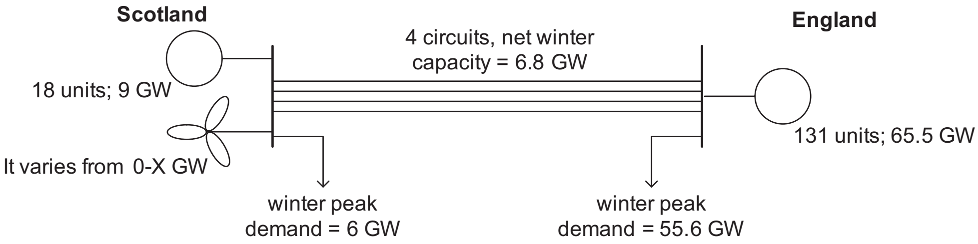

Fig. 3 Simplified electric diagram of the analysed example

(b) the cost of expected transmission constraints under contingencies or reserve utilization 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 $\tau^{pf=2}$);
(c) the 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;
(d) the cost of expected SPS utilization 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;
(e) the 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 of these summations are based on the multiplication of a power volume (in MW), a price (in £/MWh or £/MW/h or £/MW/event), and, in some cases, a time period (in h) and a probability (in p.u.: per unit).

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 network components are obtained from their failure rates assuming an exponential distribution according to reference [**17**] as shown in equation (2)

$$Pr_i = 1 - e^{-\lambda_i \times T} \tag{2}$$

Common mode failures for double circuits are also considered. For further details see Appendix 3.

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 ($pf=1$) time window (i.e. right after the outage occurs and up to 10 min); and the slow action ($pf=2$) time window (i.e. the following 20 min). This allows the model to take account of both response and reserve actions from generation and to track the progress of all other variables while re-dispatch actions are taking place after a fault occurs.

To speed up the optimization, this model uses linear d.c. power flow equations. Impacts of model simplifications on main results are explored in section 3.2.6.

The model has been developed in FICO Xpress v7.0 (Fair Isaac Corporation, Minneapolis, USA) with an Excel 2010 (Microsoft® Corporation, Redmond, Washington, USA) interface, which has allowed the three GB transmission licensees (i.e. National Grid, Scottish Power, and Scottish and Southern Energy) to run studies during the Fundamental Review of the SQSS. (This review was commissioned by Ofgem (the Office of Gas and Electricity Markets) in order to identify the flaws and the potential room for improvement in the current deterministic security standards.) For further details about the model see Appendix 2.

3 THE ASSESSMENT: ENGLAND–SCOTLAND INTERCONNECTOR

3.1 System parameters

The four-circuit England–Scotland interconnector is assessed along with future wind, conventional generation, and demand backgrounds. It is expected that by 2020 there will be about 10 GW of wind generation connected in Scotland and so this analysis considered various levels of wind output.

Annual outage rates for fair and adverse weather were populated and provided by the three GB transmission licensees. VoLL, SPS utilization, response, and reserve prices represent typical values observed. Constraint 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 briefly

Table 1 Net O + X cost for fair and adverse weather – 5.5 GW of wind output

Fair weather				Adverse weather			
Transfers (MW)	O (£/30 min)	X (£/30 min)	Total $O+X$ (£/30 min)	Transfers (MW)	O (£/30 min)	X (£/30 min)	Total $O+X$ (£/30 min)
3400	22 788	2281	25 069	3400	22 788	2306	25 095
3967	19 617	2285	21 902	3967	19 618	2381	21 999
4400	16 764	2289	19 053	4400	16 796	2645	19 440
5100	16 426	2327	18 752	5100	16 518	3877	20 395
5667	16 089	2386	18 475	5667	18 787	3077	21 864
6100	15 752	2640	18 392	6100	19 222	4546	23 768
6800	15 438	3370	18 808	6800	22 511	5625	28 176

shows a general scheme of the problem. Detailed data can be found in Appendix 3.

In this section, a number of sensitivity analyses 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.

3.2 Results and analysis

3.2.1 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 [**16**].

In this respect, Table 1 shows the total cost of network operation with different levels of power transfer across the 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 conditions and 4.4 GW for adverse weather conditions. If transfers are limited at lower levels, the system operates at a higher operational cost (mainly driven by constraint cost). In contrast, if higher transfers are accepted, then the system is exposed to increased levels of risk.

For adverse weather conditions, it can be observed in Table 1 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 3.2.3). 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.

3.2.2 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 (Fig. 4).

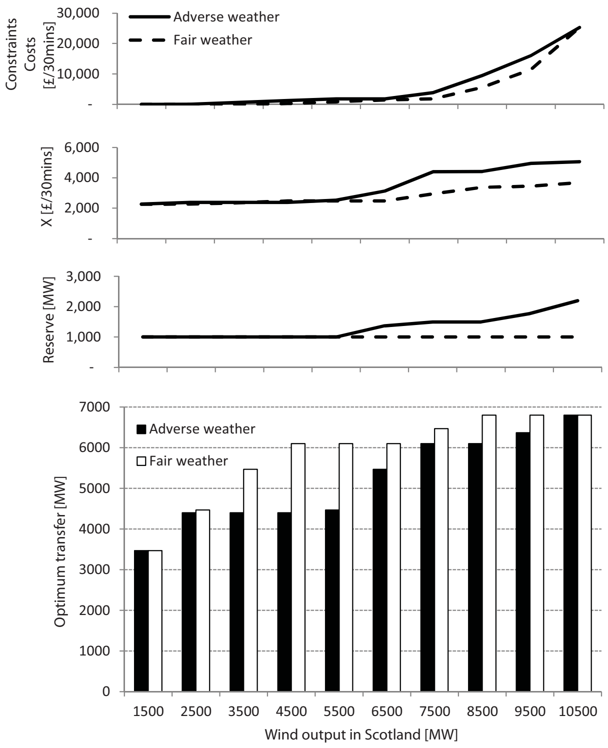

Fig. 4 Optimum transfer, reserve, expected unsupplied demand cost, and constraint cost for adverse and fair weather when considering various levels of wind output

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

Table 2 Reserve commitments and expected generation and demand shed costs for adverse weather at different power transfers accepted – 5.5 GW of wind output

Transfers (MW)	Reserve (MW)	Generation shed (£/30 min)	X (£/30 min)
3400	1000	0	2306
3967	1000	1	2381
4400	1000	33	2645
5100	1000	95	3877
5667	1500	204	3077
6100	1633	313	4546
6800	2199	1153	5625

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.

3.2.3 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 2 shows that to maintain an optimum cost balance while facilitating increased power transfer over the England–Scotland interconnector, both generation reserve commitments and SPS expected utilization increase.

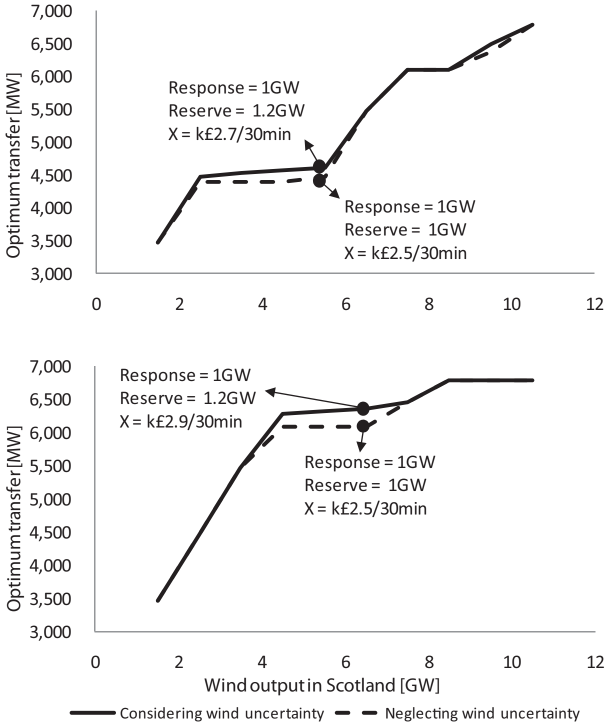

Fig. 5 Optimum transfer for adverse (a, top) and fair weather (b, bottom) with respect to wind outputs when considering wind uncertainty

Interestingly, 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.

(a) *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, Fig. 5 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 need to be located in the importing area to facilitate application of SPS.

It is important to note that there may be a correlation between weather conditions and wind power availability which may impact power transfers (high wind outputs may be caused by adverse weather conditions).

3.2.4 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 may be failures in the communication system that may lead to malfunctions of SPS and, in turn, to widespread disconnections of load. In this section an 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. Total expected costs for two specific power transfer levels of 4.4 and 6.1 GW are presented, considering various degrees of confidence regarding weather conditions. If, for example, it is 100 per cent certain that the

Table 3 Robustness of decisions when considering uncertainties in the prediction of weather conditions –5.5 GW of wind output

Probability (%) of		Expected cost (£/30 min) 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

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 per cent certainty, the optimal power transfer should be increased to 6.1 GW. It is possible to observe from Table 3 that a higher power transfer of 6.1 GW could be permitted if the probability of having fair weather is higher than or equal to 90 per cent.

Additionally, other uncertainties like malfunctions of SPS or the presence of hidden failures (failures that remain unrevealed under normal system conditions [**18**, **19**]) can also be assessed within the proposed cost–benefit framework. Figure 6 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. (Response and reserve availability were fixed according to the optimum transfer conditions, (i.e. 1GW of each service during fair weather, and 1 and 1.5GW of response and reserve, respectively), during adverse weather.) This shows how the power transfers become more constrained when the probability of having malfunctions increases.

Interestingly, it can be noticed from Fig. 6 that even for a high probability of malfunctions (100 per cent) together with large amounts of non-optimum demand shedding (40 times), the optimum transfers remain above the limit given by an *N*–2 deterministic policy, namely 3.4 GW.

Finally, it is worthwhile mentioning that this framework was tested against an array of uncertainties in market conditions and was proved to be robust for a range of credible market prices for network constraints, response, and reserve services, VoLL, and levels of utilization of SPS. Complementary work can be found in references [**20**] and [**21**].

3.2.5 *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:

(a) optimum probabilistic;
(b) *N*–2 deterministic (present UK standard);
(c) *N*–1 deterministic.

Figure 7 summarizes the key findings of this exercise for two different wind penetration levels. As expected, it is observed that the benefits of the 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 (Fig. 7(b)) the cost across the three different transfer policies analysed varies significantly, while smaller changes are observed for lower wind penetration levels (Fig. 7(a)). In addition, changes in the cost of constraints are more significant than changes in the costs of generation-based services and expected unsupplied demand.

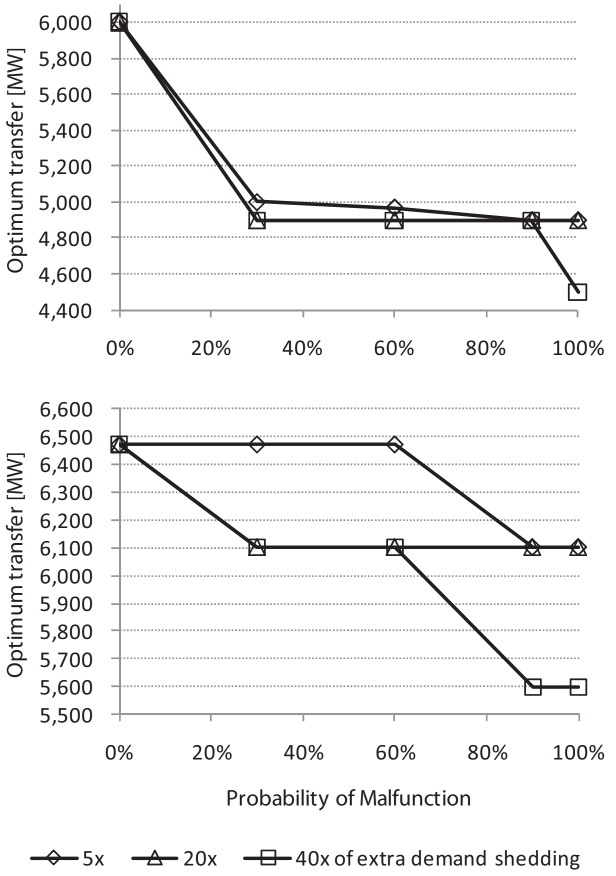

Fig. 6 Optimum transfer when considering malfunction events for adverse (a, top) and fair (b, bottom) weather –7.5 GW of wind installed capacity

Figure 7 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. the England–Scotland energy marginal price differential) increases as the volume of constraints increases, especially under high wind penetration. This ultimately fosters higher network utilizations and the increased use of post-fault actions centred on generation-based resources to guarantee system security on a constant basis.

3.2.6 *Limitation of the case studies*

The results obtained suggest that there is potentially a large benefit in 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:

(a) increased amount of losses that will be accompanied with increased power transfers;

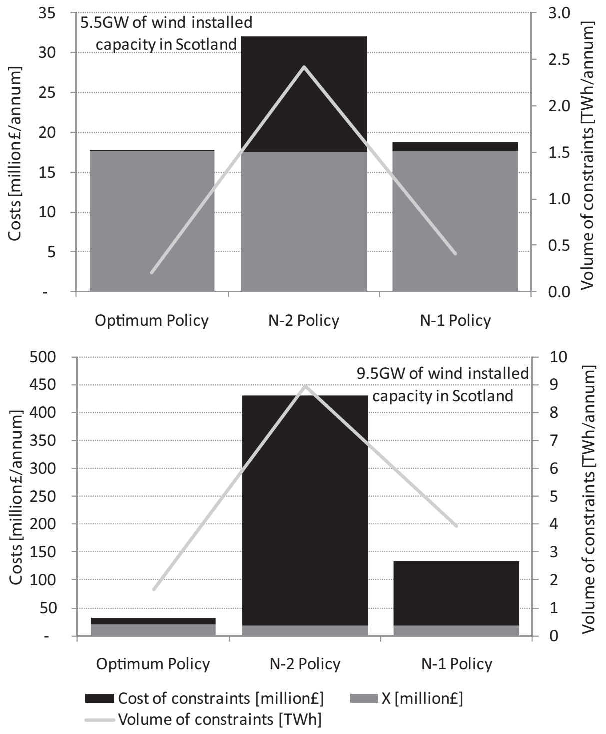

Fig. 7 Annual operational costs and volume of constraints under different transfer policies, i.e. under different transmission upper limits, for 5.5 GW (a, top) and 9.5 GW (b, bottom) of wind installed capacity

(b) the development of demand response policies which may reveal more information with respect to VoLL across different consumer types;
(c) VoLL that may vary widely across different consumer types;
(d) the effect of dynamic or stability constraints that will become increasingly more important with increased power transfers;
(e) application of DLR;
(f) correlation of weather and wind generation conditions.

Conceptually, however, these effects could be integrated within the probabilistic operational standards and this is recommended for future investigations.

4 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 England–Scotland interconnector suggests that the network capacity that can be optimally released to users changes significantly depending on actual system conditions. These include:

(a) the level of constraint costs associated with the particular operating condition that would be driven by the level of wind power output (that varies significantly);
(b) weather conditions that are also variable and can be optimized to take account of costs 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 utilization, 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.

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APPENDIX 1

Notation

bid_g^c	accepted bid from generator g at operating state c (MW)
d_n	total power demand at node n (MW)
$f^{c},^{pf}$	power flow at operating state c during post-fault condition pf (MW)
$\bar{f}^{c,pf}$	circuit rating at operating state c during post-fault period pf (MW)
$itrp_n^c$	SPS (also called inter-tripping) utilized 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)
M	number of operating states
$nres_g$	accepted reserve service from generator g (MW)
$nrsp_g$	accepted response service from generator g (MW)
N_g	number of generators
off_g^c	accepted offer from generator g at operating state c (MW)
$\underline{p}_g, \overline{p}_g$	minimum stable generation and maximum output of generator g (MW)
$p_g^{c,pf}$	output of generator g at operating state c during post-fault period pf (MW)
p_g^{ED}	unconstrained dispatch output for generator g (MW)
$pout_n^{c,pf}$	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 network component i will be outaged (p.u.)
res_g^c	utilized reserve service from generator g at operating state c (MW)
rsp_g^c	utilized response service from generator g at operating state c (MW)
T	lead time (h)
$voll_n$	value of lost load at node n (£/MWh)
γ_g	scheduling status of generator g; 1 if on, 0 otherwise (binary)
$\Delta rspup_g$	net response that generator g can provide when ramping up (MW)
$\Delta resup_g$	net reserve that generator g can provide when ramping up (MW)
$\Delta resdwn_g$	net ramping down limit for generator g during reserve period (MW)
λ_i	failure rate of network component i (occurrences/h)
πbid_g	bid price submitted by generator g (£/MWh)
$\pi itrp_n$	itilization price of SPS (also called inter-tripping schemes) provided at node n (£/MW)
πoff_g	offer price submitted by generator g (£/MWh)
πres_g	price of holding reserve services provided by generator g (£/MWh)
πrsp_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)

APPENDIX 2

The model

(a) *Model simplifications*

Because the final application is on a bulk interconnector in which the resistance of the entire line has a very small value, a d.c. optimal power flow (DC-OPF) is used and losses have been neglected.

An average rather than real unique generation size is considered (e.g. 500 MW).

(b) *Main constraints*

In each operating state, supply and demand must be balanced:

$$\sum_{g=1,\dots,Ng} p_g^{c,pf} - \sum_{n=A,B}\left(itrp_n^c + pout_n^{c,pf}\right) = \sum_{n=A,B} d_n - \sum_{n=A,B} ll_n^{c,pf}, \qquad \forall c, pf \tag{3}$$

Equation (4) ensures that there is no load shedding and no generation inter-trips during the intact condition ($c=1$)

$$\begin{aligned} ll_n^{c=1,pf} &= 0, \qquad \forall pf, n \\ itrp_n^{c=1} &= 0, \qquad \forall n \end{aligned} \tag{4}$$

The 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 equation (5)

$$\underline{p}_g \cdot \gamma_g \leqslant p_g^{c,pf} \leqslant \bar{p}_g \cdot \gamma_g, \qquad \forall c, pf, g$$

$$\gamma_g \text{ is binary}, \qquad \forall g$$

$$p_g^{c=1,pf} + nrsp_g + nres_g \leqslant \gamma_g \cdot \bar{p}_g, \qquad \forall g \tag{5}$$

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 equation (6), the volume of accepted bid and offer for a particular generator in an intact system is calculated

$$p_g^{c=1,pf} = p_g^{\mathrm{ED}} + off_g^{c=1} - bid_g^{c=1}, \qquad \forall g, pf \tag{6}$$

In equation (7), the bid or offer accepted is measured during a contingent state for generator g

$$p_g^{c,pf=2} = p_g^{c=1,pf=2} + off_g^c - bid_g^c, \qquad \forall c \neq 1, g \tag{7}$$

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, equation (8)

$$p_g^{c,pf=1} = p_g^{c=1,pf=1} + rsp_g^c, \qquad \forall c \neq 1, g$$

$$rsp_g^c \leqslant \Delta rspup_g, \qquad \forall c \neq 1, g$$

$$rsp_g^c \leqslant nrsp_g, \qquad \forall c \neq 1, g \tag{8}$$

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 utilized 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 equation (9)

$$p_g^{c,pf=2} \leqslant p_g^{c=1,pf=2} + res_g^c, \qquad \forall c \neq 1, g$$

$$res_g^c \leqslant \Delta resup_g, \qquad \forall c \neq 1, g$$

$$res_g^c \leqslant nres_g, \qquad \forall c \neq 1, g$$

$$p_g^{c,pf=2} \geqslant p_g^{c=1,pf=2} - \Delta resdwn_g, \qquad \forall c \neq 1, g \tag{9}$$

In all operating states, the power flows cannot exceed the rating of circuits. Pre-fault rating is used in the intact system (c=1), short-run post-fault rating is used in $c\neq1$ and $pf=1$, and long-run post-fault rating is used in $c\neq1$ and $pf=2$, equation (10)

$$-\bar{f}^{c,pf} \leqslant f^{c,pf} = \sum_{g \in A} p_g^{c,pf} + ll_A^{c,pf}$$

$$-\left(d_A + itrp_A^c + pout_A^{c,pf}\right) \leqslant \bar{f}^{c,pf}, \qquad \forall c, pf \tag{10}$$

Inter-trip is modelled as a linear variable ($itrp$) that can trip the optimal amount of generation output when it is necessary; for example, in order to avoid thermal overloading of other circuits when outage happens at one or more network circuits. Inter-trip is only used during contingent states which involve network circuit outages as shown in equation (11)

$$itrp_n^c \leqslant \sum_{g \in n} p_g^{c=1,pf=1}, \qquad \forall c \neq 1, n$$

$$itrp_n^c = 0, \qquad \forall c \neq 1, n \text{ with no line outages} \tag{11}$$

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

APPENDIX 3

Relevant input data

(a) *Generation data* (see Table 4)
(b) *System prices*

Response availability: 20 £/MW/h
Reserve availability: 10 £/MW/h
SPS utilization: 1000 £/MW/event
VoLL: 30 000 £/MWh

(c) *Outage probabilities* (see Table 5)
(d) *Wind variations* (see Table 6)
(e) *Regarding the year-round studies*

In total, 8760 h are represented through 510 snapshots which combine: five typical days per season (summer intact, summer planned outage, winter,

Table 4 Generation data: (1) installed capacity in Scotland (no. of units); (2) installed capacity in England (no. of 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) winter generation availability (%)

Generation technology	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Wind	3	0	0	–50	N/A	0	0	N/A
Nuclear	5	17	0	–100	N/A	0	0	88
Combined heat and power	0	3	0	–50	N/A	0	0	73
Base gas	0	24	30	30	30	50	200	96
Base coal	1	27	35	35	35	50	200	95
Interconnector	0	4	50	50	50	0	0	99
Water	2	0	80	80	80	50	200	98
Marginal gas	3	21	90	90	90	50	200	96
Marginal coal	6	23	100	100	100	50	200	95
Pump storage	1	3	200	200	200	50	200	98
Oil	0	7	210	210	210	50	200	95
Peakers	0	2	300	300	300	50	200	95

Table 5 Fault rates and outage probabilities

	Single circuit		Double circuit		Generation
	Fair weather	Adverse weather	Fair weather	Adverse weather	All weather
Fault rate (occurrences/day)	1.4×10^{-3}	4.6×10^{-2}	1.4×10^{-4}	4.6×10^{-3}	4.9×10^{-2}
Lead time (h)	0.5	0.5	0.5	0.5	0.5
Pr	2.9×10^{-5}	9.5×10^{-4}	2.9×10^{-6}	9.5×10^{-5}	1.0×10^{-3}

Table 6 Wind forecast errors

Wind scenario (only low-frequency events)	Wind output availability change with respect to expected situation (p.u.)			Probability (p.u.)
	Representative value	15 min (used for response)	60 min (used for reserve)	
1	μ	0	0	0.6827
2	$\mu - 1.5\times\sigma$	–0.01039	–0.0406	0.1359
3	$\mu - 2.5\times\sigma$	–0.01732	–0.0677	0.0214
4	$\mu - 3.5\times\sigma$	–0.02425	–0.0947	0.0013
5	$\mu - 4.5\times\sigma$	–0.03118	–0.1218	3.13846×10^{-5}

μ, mean; σ, standard deviation.

spring, and autumn), five demand levels per day, two types of weather conditions (fair and adverse), and ten wind levels. In addition, an extra demand level is added in order to represent the peak demand condition; this considers only adverse weather and winter period along with ten wind levels.

The durations of the snapshots represent: 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 per cent/3 per cent. Remaining seasons are composed of 88 per cent and 12 per cent of fair and adverse weather, respectively.

A 30 per cent load factor wind profile is represented through ten discrete outputs together with their probabilities.

Line ratings are adjusted per season according to the following multiplying factors: 1 for winter, 0.85 for spring and autumn, and 0.7 for both summers. Only three circuits are in operation during summer planned outage period. Generation availabilities change in each season.