DTI Centre for Distributed Generation and Sustainable Electrical Energy

Summary Report

Transmission Investment, Access and Pricing in Systems with Wind Generation

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1. Executive summary

Background

1.1 Wind power is and will continue to be the most important new generation technology in terms of its contribution to meeting Government targets on renewables. More than 16GW of wind generation have applied to connect to the onshore distribution and transmission network in Great Britain.

1.2 The most significant activities in the field of Distributed Generation (DG) are in Scotland and North of England. However, at present, the developers of even relatively modestly sized wind farms in Scotland (up to 50MW would be normally connect to distribution networks) find it very difficult (in many cases impossible) to obtain timely grid connection agreements, due to the limited capacity of the existing transmission network and the regulatory and commercial arrangements associated with connections. In addition to various administrative issues associated with the development of wind power projects, *the insufficiency in the GB transmission network capacity to absorb the outputs of the existing and new generation is the key barrier to grid integration of DG in the short and medium term*.

1.3 In this document we conclude that wind power (as well as other DG technologies) is significantly different from conventional generation, as its output is driven by weather conditions rather than electricity demand. *The present technical, commercial and regulatory framework associated with transmission access was designed for a system with conventional generation only, and it will need to be modified as, in its present form, it is unable to facilitate cost effective integration of different technologies of DG (and wind in particular) into the GB electricity system.*

1.4 We also present the key results of our recent work on network security standards in systems with conventional and wind generation and examine the implications for transmission network access, investment and pricing. We believe that resolving these issues is of critical importance to cost effective integration of wind power (and other DG technologies) into the GB electricity system.

1.5 More specifically, the primary focus of this document is on the implications of connecting significant amounts of wind power for transmission network investment, pricing, and access arrangements. The areas discussed include:

(i) Transmission network capacity and investment in systems with wind energy;

(ii) Cost reflective pricing of transmission in systems with wind energy and adequacy of present arrangements; and

(iii) Appropriateness of the present concept of TEC in systems with wind power.

Transmission network capacity and investment in systems with wind energy

1.6 The Great Brittan Supply Quality and Security Standard (GBSQSS) drives the design of the GB Transmission Network and was developed for systems with conventional generation. Its underlying philosophy is centred on the requirement that transmission capacity should be sufficient to ensure that generators in remote areas are not unduly restricted from contributing to security of supply of local loads. The network planners traditionally would consider conditions of *peak demand* to determine the need for transmission network capacity across the major transmission boundaries based on security requirements. For a system with conventional generation (generation that is demand driven), network design driven by peak condition has been generally adequate also for a wide range off-peak conditions including planned outages of both generation and transmission facilities.

1.7 It is important to stress that, at present, there is no consensus regarding the methodology for determining the need for transmission capacity in systems that include non-conventional generation technologies, such as wind. However, *all* recent UK work in this area suggests that *wind generation drives less transmission investment than conventional generation* and that *wind and conventional generation should share transmission capacity*. When determining the need for transmission capacity, the scaling factor used in the GB SQSS for conventional plant is 83%[1], while various *lower value* scaling factors[2] are proposed for wind generation: 60% by National Grid[3], while SKM work[4] indicates a significantly lower figure of about 20%.

1.8 More recently, in consultation with all relevant industry stakeholders including the three transmission owners, we have developed a *rigorous* methodology based on the philosophy of the existing GB SQSS but extended to include wind generation technology. This was based on an analysis of the performance

[1] Considering historical generation margin above demand of 20%, in order to balance demand and generation for transmission design, generation output is scaled by 0.83, which is 1/1.2.
[2] The lower the scaling factor the lower the contribution to transmission capacity.
[3] Report available at www.ofgem.gov.uk
[4] Report available at www.ofgem.gov.uk

of the present standard from which we concluded that the (finite) capacity of the transmission network determined in accordance with the existing GB SQSS increases the risk that the system will not be able to meet peak demand by about 5%. This transmission network related risk is then used as a benchmark for assessing the required transmission capacity for a system with intermittent generation. Given the limited contribution that wind power makes to security, we demonstrated that the scaling factors appropriate to be applied to wind should be in the region between 30% and 40% (and will depend on the level of penetration, wind diversity characteristics and load factors).

1.9 Economic considerations may require additional network capacity to be installed to allow efficient utilization of low marginal cost generators. By conducting a cost-benefit analysis, decisions taken to reinforce transmission can be justified if the savings in the marginal reduction in generation costs (marginal cost of constraints) is greater than the marginal transmission network investment cost. We have developed investment optimisation methodology that, through simulation and optimisation of the system operation across an annual time horizon, balances the annual generation costs and annuities investment costs in order to analyse the need for transmission system reinforcements.

1.10 In areas dominated by wind power, with limited scope to constrain-off conventional generation (on windy days), the optimal capacity of transmission should be equal to the installed capacity of wind power, given that it is generally significantly more costly to curtail wind than invest in transmission (a typical example of this would be transmission line from Beauly to Danny). However, in areas with a mix of conventional and wind generation, costs of constraints could be significantly lower (as these would be determined by the fuel cost differentials between generation in Scotland and England) and hence the optimal network capacity built would require wind and conventional generation should share it.

1.11 Although it is in principle appropriate that a cost-benefit analysis is applied in determining network capacity and investment, the exact methodology that is used is not defined in sufficient detail. Furthermore, this approach also relies on a range of assumptions that may be contentious, including future generation technology distributions, fuel costs, projection of future constraint costs and their variations in time and space, network reinforcement cost (that may also vary significantly). The accuracy of the results could significantly depend on the accuracy of the modelling process. However, not only the *values* that would be used in such evolutions but also the *basis* on which these values should be derived are debatable. In addition, there are questions as to whether and how the short-term imbalance prices should be used as signals for making decisions on long-term transmission investment, given their volatility. There are also significant uncertainties associated with the conversion of the applications for connecting wind power into actual projects due to difficulties of obtaining planning consents and other reasons.

1.12 It is clear that these issues are very significant and hence the application of the cost-benefit analysis in practice is often very difficult and controversial. We hence propose that the existing GB SQSS should be extended to include wind power using the philosophy of the present standard given that it requires significantly less data and can deliver considerably more robust solutions. This standard would constitute *a minimum standard* while leaving the opportunities to increase the transmission capacity above the minimum if it could be justified on the basis of cost-benefit assessment

1.13 In order to illustrate the differences in alternative approaches we used our generic GB network model and analysed the transmission investment requirements caused by the connection of 10 GW of wind power in Scotland. We found that the network will need to be reinforced due to both security and economic reasons. In this analysis we assumed that no conventional plant will be decommissioned in Scotland (worst case scenario). From Table I we observe that, for example, the network capacity across the boundary between Scotland and England should increase to 4.3 GW, considering security, 5.4GW, considering economics, and 7.6GW if the present GB SQSS is applied. However, when the capacity of transmission is driven by wind power (e.g. Beauly-Denny line), the cost benefit analysis carried out in this report broadly supports the GB SQSS results.

TABLE I

COMPARISON OF TRANSMISSION CAPACITIES ASSOCIATED WITH KEY SYSTEM BOUNDARIES FOR 10GW WIND POWER IN SCOTLAND AND 3GW IN ENGLAND FOR THE THREE APPROACHES ANALYSED.

From	To	Security	Economics	GB SQSS
NW-SHETL	N-SHETL	2100	2437	2561
N-SHETL	S-SHETL	3500	3571	4439
S-SHETL	N-SPTL	3300	4110	4904
N-SPTL	S-SPTL	4100	3564	5438
S-SPTL	UN-E&W	4300	5357	7667
UN-E&W	N-E&W	4700	4935	7514
NW-E&W	N-E&W	2400	1942	2424
NE-E&W	N-E&W	5600	2218	4895
N-E&W	M-E&W	8700	7870	10674
MW-E&W	M-E&W	6800	4798	6848
ME-E&W	M-E&W	5400	4459	4869
M-E&W	S-E&W	8100	8434	9206
SW-E&W	S-E&W	3400	2781	4360
SE-E&W	S-E&W	5100	1438	4766

1.14 It is important to point out that the total installed capacity of generation in Scotland (conventional and wind) in these case studies reaches 19.5 GW while the peak of the local load is about 6.5 GW. This result clearly demonstrates that is not efficient to invest in transmission in order to be able to accommodate simultaneous peak outputs from both conventional and wind generation. The diversity effect is of a major significance. Instead, the transmission capacity should be shared between conventional generation and wind. In other words, on windy days the capacity of transmission corridor between Scotland (S-SPTL) and England (UN-E&W) is primarily used to transport wind power, while on non-windy days, this capacity would be used to export energy from conventional plant. However, the current approach to access and pricing of transmission is not consistent with this finding, and hence creates a need to elaborate on these issues further.

1.15 This example demonstrates that wind generation tends to drive less transmission investment than conventional generation, particularly when there are opportunities for the sharing of transmission assets between different generation technologies.

Cost reflective pricing of transmission in systems with wind energy and adequacy of present arrangements

1.16 The present Transmission Network Use of System (TNUoS) charging methodology was developed for a system with conventional generation only and is consistent with the present GB SQSS. It considers a single peak demand condition and the location specific network charges are evaluated on the basis of the impact that individual users have on the need for transmission under this condition. Given the assumption that all generators operate during peak conditions, generators connected in the same area would have the same impact on the transmission network investment and hence will be exposed to the same TNUoS charges. This is clearly inappropriate for systems with mixes of conventional and various forms of distributed and renewable generation technologies, such as wind. What is important in this context is to determine the distinct contributions that individual generation technologies have on transmission network investment costs. Hence generators in the same area could impose very different demands for transmission network investment. *In other words, if non-discriminatory access to transmission network is to be established, TNUoS charges would need to discriminate between generation technologies.*

1.17 Following this approach, while applying different scaling factors for conventional and wind generation we proposed a simple modification of the present TNUoS charging mechanism[5] in order to recognise the diverse contributions of individual generation technologies to transmission network costs and hence to achieve cost reflectivity. Similarly, we also evaluated cost reflective TNUoS charges for a cost-benefit approach to network investment. Two sets of charges are evaluated consistent with the two drivers of network investment, i.e. security and economics,. The results presented in TABLE II are for the cases of 10 GW of wind generation in Scotland and 3 GW of wind generation in England. Both pricing methodologies result in location specific charges. As expected, generators in the North will drive the cost of transmission and hence should be charged, while generators in the South will be rewarded as they contribute to the reduction transmission capacity.

[5] We believe that the proposed medications can be immediately implemented, as these are within the philosophy of the present TNUoS framework.

TABLE II

TRANSMISSION CHARGES (£/KW/YEAR)

Nodes	Charges based on security		Charges based on cost-benefit	
	Wind Generation	Conventional Generation	Wind Generation	Conventional Generation
NW-SHETL	9.07	41.53	17.90	26.66
N-SHETL	7.10	37.31	15.46	14.77
S-SHETL	5.81	33.99	13.22	27.89
N-SPTL	0	24.53	0	12.22
S-SPTL	2.09	21.78	5.87	13.40
UN-E&W	0	16.20	0	5.27
NW-E&W	0	2.96	0	6.45
NE-E&W	0	8.43	0	2.99
MW-E&W	0	-2.94	0	-9.18
ME-E&W	0	3.35	0	0.73
SW-E&W	0	-20.41	0	-12.18
SE-E&W	0.51	-5.11	-3.93	-3.92
S-E&W	0	-9.59	0	-1.37

1.18 These results demonstrate that the cost reflective TNUoS charges for wind, when the transmission investment is driven by security, tend to be significantly lower than the charges for conventional generators, which reflect the differences in generation capacity credit associated with wind and conventional generation.

1.19 The results of the allocation of transmission network cost based on economics show that in most cases wind generation should pay lower TNUoS charges than conventional generation. However, in areas where wind generation dominates conventional generation (i.e. transmission is built to accommodate high wind penetration levels), then the charges for wind power may be higher than those for conventional generation.

Appropriateness of the concept of TEC in systems with wind power

1.20 Although the concept of Transmission Entry Capacity (TEC) is attractive in principle, the key problem of the present implementation and interpretation of this instrument is its lack of the consistency with the transmission investment process, transmission network pricing and possible adverse impacts on the efficiency of generation system operation and network investment.

Inconsistency of TEC and transmission investment

1.21 We demonstrated TEC associated with an individual generator is not directly linked with the need for transmission capacity on the main interconnected system that this generator imposes, particularly in systems with generators of different technologies. It is clear that different generation technologies may drive different investment of the main transmission network and that this is not reflected in the value of TEC. This is critically important as the absence of a link between TEC and transmission investment cost means that an efficient price for TEC cannot be transparently determined. In other words, as TEC cannot be directly linked with the need for transmission investment that the user imposes, there is no mechanism that would allow efficient and transparent valuation of TEC. As the concept of TEC, in its present format, does not provide the basis for transmission reinforcement, it should not be used as the indictor of user commitment for future network investment.

Inconsistency between TEC and TNUoS charging methodology

1.22 Given that the TEC required by a user is not directly relevant in determining the impact that the user makes on long-term marginal transmission investment cost, then using TEC for pricing is clearly not cost reflective. Hence the concept of TEC has little significance in the context of network pricing in systems with a mix of generation technologies.

Inefficiency of generation system operation caused by the introduction of TEC

1.23 Generators that purchase a certain amount of TEC that is lower than the installed capacity of their generation would be prevented from generating in excess of the TEC purchased, irrespective of whether the network is congested or not. This is clearly inefficient, as these users are unnecessarily prevented from accessing the transmission network (and hence the energy market) when the short-term marginal cost of using this transmission capacity is minimal (close to zero). This will require the operation of higher cost generation and in turn will lead to an increase in electricity prices.

Inefficiency of transmission investment caused by the concept of TEC

1.24 The process of converting TEC into investment capacity decisions is not clear. The present approach to assessing the need for transmission capacity between large areas does not adequately take into account the effect of diversity, which is fundamental to achieving efficient development of the transmission network. The values of TEC for individual generators tend to be simply added together and this will clearly lead to over-investment in transmission.

1.25 Furthermore, if the amount of TEC issued to transmission network users matches the available transmission capacity, this would be clearly inefficient, because a constraint free transmission network is uneconomic. An economically efficient transmission system should be optimally constrained rather than operate in a constraint free mode.

Possible ways forward

1.26 There are a number of possible approaches to addressing the inconsistencies in the present transmission network access, investment and pricing arrangements. Given the complexity of these arrangements, it would be appropriate that a coordinated debate with all interested parties is held through appropriate forums and corresponding consultation processes. In principle, we have identified two extreme positions that could be considered:

(i) ***Administered arrangement***: all users could be given (almost) firm long-term access to the transmission network as the present concept of TEC is not relevant to network design and pricing of the main interconnected network in systems with mixes of different generation technologies. The transmission network could be designed in accordance with an appropriately updated GBSQSS that facilitates the sharing of transmission capacity between generators of different technologies. The TNUoS charging methodology could be modified to achieve cost reflectivity, as discussed in this report. Costs of network constraints could be administered. The volumes and costs of constraints could be closely monitored and the need for investment in transmission periodically reviewed.

(ii) ***Market based access arrangement***: develop a market for transmission access with fully tradable transmission access rights that reflect the time varying (probably half hourly) and location specific short-term marginal cost of network capacity, that can be hedged by long-term, location specific (and possibly time varying) products, efficiently priced at the marginal investment cost of transmission. This approach will require the question of the re-allocation of transmission access rights of incumbents to be resolved. Clearly, if the incumbent generators continue to hold transmission rights in Scotland, the market value of these rights (particularly during high wind regimes when the network become congested) could reach the value of Renewable Obligation Certificates (ROCs), in which case the conventional, rather wind generation, would benefit from ROC-related income. In this context, for example, it is worth pointing out that Cockenzie, which is one of the least efficient large generating stations in the entire GB system, currently holds 1000MW of transmission access rights and prevents the connection of zero marginal cost, CO_2 free wind generation.

2. Introduction

2.1 Wind power is presently the principal commercially available and scaleable renewable energy technology and is expected to deliver the majority of the required growth in renewable energy generation in many countries that are committed to fulfil their targets of renewable generation. The UK has probably the most significant wind power resource in Europe and there is more than 16GW of applications for connecting wind power in Scotland and more than 8GW potentially to be connected offshore (primarily off England).

2.2 One of the key challenges of this technological development is to ensure the cost effective integration of these resources into the operation and development of Great Britain's electricity system without compromising the security of supply. Potential operational problems would stem from three principal causes, namely, (i) the variable (intermittent) nature of the output of wind generation, (ii) the location and remoteness of the resource relative to centres of demand and (iii) the unusual form of generation technology used.

2.3 The primary focus of this summary report is on the implications of connecting significant amounts of wind power for transmission network investment, pricing, and access arrangements given the location of wind generation (Scotland) relative to load centres (England) and the need to reinforce the existing transmission network. A number of key areas are investigated:

(i) Transmission network investment in systems with wind energy. We developed a rigorous approach to determining the need for transmission network investment in systems with mixes of conventional and wind generation. We show that conventional and onshore wind generation should share transmission network capacity.

(ii) Cost reflective pricing of transmission in systems with wind energy and adequacy of present arrangements. As the results of the investment studies conclusively demonstrate that wind generation drives less transmission investment, we examine how the TNUoS charging philosophy should change to reflect this.

(iii) Weaknesses of the application of the concept of TEC in systems with wind power. We have critically examined the weaknesses of the application of the concept of TEC (as it is being implemented at present) and concluded that TEC does not reflect need for investment and should not therefore be used for network pricing. In addition we point out that the concept of TEC can lead to inefficiencies in system operation and network investment.

3. Transmission network investment in systems with wind energy

3.1 Overview of the traditional approach to transmission network planning and investment

3.1 Optimising transmission investment is a very complex task. A number of factors need to be considered, including forecasts of growth in demand and generation with their temporal and spatial distributions together with the technical and cost characteristics of generation. These forecasts must then be combined into a forecast of future energy market conditions in order to answer the key questions as to how much, where, when and what transmission reinforcements are justified. Evaluating possible schemes involves comprehensive technical, economic and reliability assessments that balance transmission investment costs, generation operating costs (cost of congestion) and the cost of un-served demand due to lack of capacity and availability of transmission. In practice, engineers tend to use simpler deterministic planning guides (also called network planning standards) that present a proxy of the comprehensive reliability and cost-benefit assessments for determining the amount of transmission capacity required to transport power across various system boundaries given a predefined set of generation and demand scenarios.

3.2 The Great Brittan Supply Quality and Security Standards (GBSQSS) drives the design of the GB Transmission Network and was developed for systems with conventional generation. Its underlying philosophy is centred on the requirement that transmission capacity across the transmission network boundaries should be sufficient to ensure that generators in remote areas are not unduly restricted from contributing to security of supply of local loads. Network planners traditionally would consider conditions of *peak demand* to determine the need for transmission network capacity across the major transmission boundaries based on security requirements. For a system with conventional generation (generation that is demand driven), network design driven by peak conditions has been generally adequate also for a wide range off-peak conditions, including planned outages of both generation and transmission facilities.

3.2 Impact of wind generation on the need for transmission network capacity

3.2.1 Background and overview

3.3 Although there is no consensus regarding the methodology for determining the need for transmission capacity in systems that include non-conventional generation technologies, all recent UK work in this area suggests that *wind generation drives less transmission investment than conventional generation* and that *wind and conventional generation should share transmission capacity*. When determining the need for transmission capacity, the scaling factor used in the GB SQSS for conventional plant is 83% while various *lower value* scaling factors are proposed for wind generation: 60% by the National Grid, while SKM work indicate significantly lower figure of about 20%.

3.4 More recently, in consultation with all relevant industry stakeholders including the three transmission owners, we have developed a *rigorous* methodology based on the philosophy of the existing GBSQSS but extended to include wind generation technology. This was based on an analysis of the performance of the present standard from which we concluded that the (finite) capacity of the transmission network determined in accordance with the existing GB SQSS increases the risk that system will not be able to meet peak demand by about 5%[6]. This transmission network related risk is then used as a benchmark for assessing the required transmission capacity for a system with intermittent generation. Given the limited contribution that wind power makes to security, we demonstrated that the scaling factor appropriate to be applied to wind should be in the region between 30% and 40%. In addition to security-driven capacity we have also developed a cost-benefit based approach that balances the cost of investment with the cost of network constraints. These are summarised in the following sections.

[6] In other words, the risk of supply increases from 9% (driven by unavailability of generation) to about 9.5%, when the finite capacity of transmission is included in the considerations. The network that was designed for a peak condition is usually adequate for other demand conditions including effects of maintenance.

3.2.2 Security driven capacity evaluations

3.5 In order to determine the required transmission network capacity in systems with wind power, we analysed the link between former generation adequacy standards and the existing GB SQSS [1]. The former generation security standard defined the statistical probability that consumers of electricity may be faced with the loss of their supplies due to insufficient generation. This was measured by the loss of load probability index (LOLP) representing the probability of the annual peak load exceeding the available generation. The generation adequacy standard used to set the probability of peak load not being supplied at 9%. This was often interpreted as the likelihood of peak demand exceeding the available generation being at most 0.09, or that generation shortages should not occur in more than 9 winters in one hundred years.

3.6 However the risk of interruptions will increase in the presence of a finite transmission network capacity. The key underlying philosophy of the GB SQSS, developed for systems with conventional generation, is associated with adequacy (reliability) of supply and centres on the requirement that transmission capacity between system boundaries should be sufficient to ensure that generators in remote areas are not unduly restricted from contributing to security of supply of loads.

3.2.3 Minimum Transmission Capacity Requirements According to GB SQSS

3.7 As discussed, the former CEGB generation security standards required that sufficient generation capacity should be made available to meet demand but with little excess, after allowing for expected breakdowns. Under these conditions *all generation is equally valuable for meeting demand*.

3.8 Thus the average power transfers on the system at peak will be determined by the average local plant/demand balances. These power transfers, termed “Planned Transfer” in the standard are obtained by scaling all generation to meet the forecast peak demand. With centrally planned generation, this scaling factor would simply be the inverse of the plant margin – thus if the margin were 20% the scaling factor applied to generation would be 1/1.20 = 0.83.

3.9 However realistically the system is unlikely to be “average” across the whole system – in some areas the generation will have higher availability than expected and in others lower. Similarly with demand. The result is that the expected transfers will have a distribution about the average or “planned transfer” value. This deviation from the average is allowed for by adding a margin to the planned transfer.

3.10 The appropriate margin was determined by analysing actual inter area flows over a period of time (1943 – 1949) and constructing a relationship between the likely maximum required transfer and the generation and demand in the smaller of the two areas under consideration. This relationship was termed "the circle diagram" (see Figure 1).

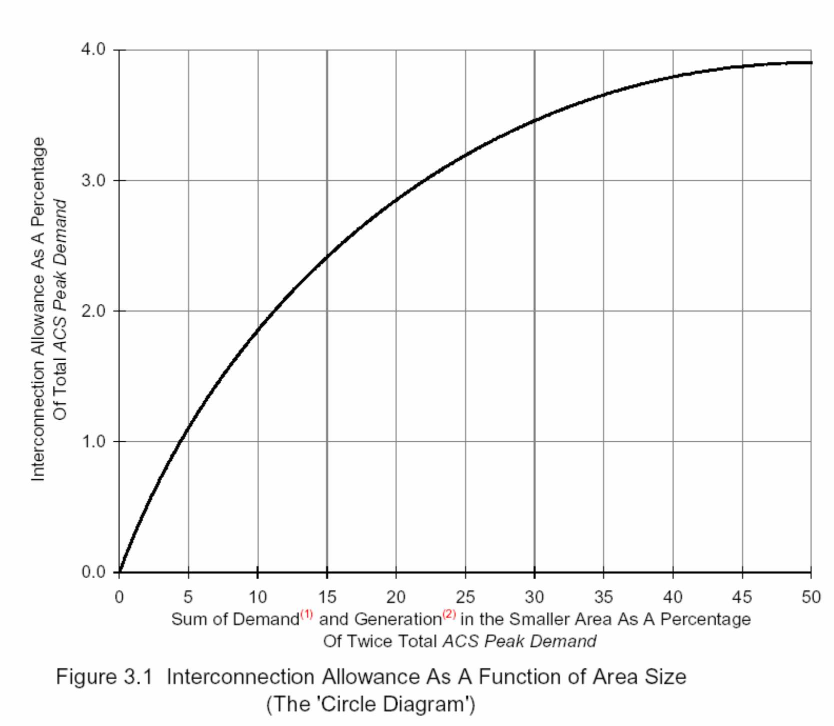

Figure 1 Interconnection allowance as a function of area size (The "Circle" Diagram)

3.11 In practice, ensuring an ability to accommodate the planned transfer plus interconnection allowance allows the system to be operated without undue economic restrictions as well.

3.12 We used these concepts to assess the additional risk that transmission system imposes to security of supply. To illustrate this, we considered a simple system equally divided into two contiguous parts. The two resultant systems, A and B, are characterised by the same generation installed capacity – 31GW – and the same peak demand – 25GW. It is assumed that the two systems A and B are interconnected by a transmission line of finite transmission capacity, as shown in Figure 2.

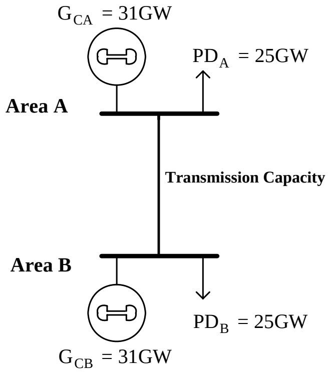

Figure 2 Schematic representation of two busbar example

3.13 Applying the concept of planned transfer we immediately concluded that the average power transfers between the two areas would be zero. However, some transmission capacity between the two areas will clearly be beneficial as it will enable sharing of reserve between the two areas and increase the overall system security. The amount of reserve that can be shared between the two areas will depend on the capacity of the transmission link. Clearly, in the case of generation shortages, say in area A, then generation in area B could support the load of area A, if the appropriate transmission capacity was available. Using the circle diagram above, we find that the interconnection allowance in this case is about 2GW (that is 4% of 50MW, given the X-axis value of 56/100 on the circle diagram).

3.2.4 Quantification of System Risk Pertinent to the Transmission System

3.14 The risk that the system will not be able to meet the demand is quantified using the methodology for the reliability evaluation of interconnected systems[7]. The impact of transmission capacity on the risk of loss of supply is presented in Figure 3, for various levels of transmission capacity.

[7] "Reliability Evaluation of Power Systems", R. Billinton, R.N. Allan, Plenum Press, New York, 1984.

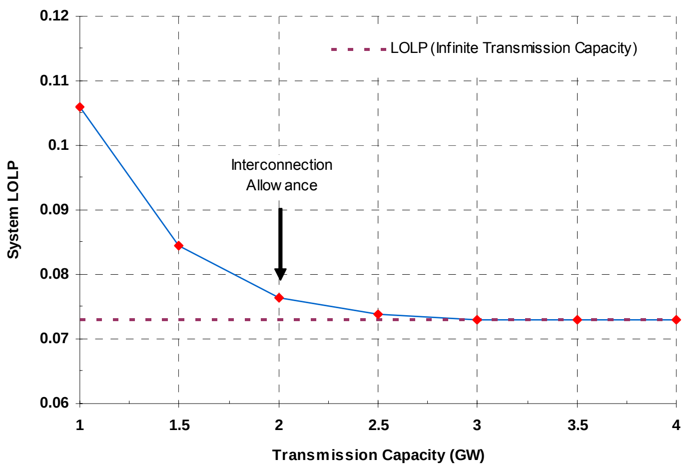

Figure 3 System Risk Imposed by Transmission System

3.15 Figure 3 shows the rapid reduction in risk (the probability that the load will not be supplied) with the increase in transmission capacity between the two areas. For transmission capacity larger than 3GW, the risk converges to a value that represents the minimum risk that such an interconnected transmission system can have under these conditions.

3.16 In the presence of a transmission link with a capacity of 2GW the risk (LOLP) of loss of supply is equal to 0.076362, while this risk has a lower value of 0.072894 for an infinitely strong transmission network. This analysis confirms that the minimum transmission capacity requirement determined by the empirically derived interconnection allowance function is quite reasonable (increasing the capacity beyond 2GW only marginally reduces the risk)

3.17 Considering the transmission link with a required capability of 2GW, determined through the application of interconnection allowance function, we can observe that the *increase* in risk (from the value of 0.072894) due to the finite capacity of transmission network (to 0.076362) is relatively modest, in this case about 5%. We have carried out extensive sensitivity studies for various configurations and concluded that the value of 5% is quite robust and can be used as representative.

3.3 Security Driven Transmission Investment in Systems with Wind Generation

3.3.1 Wind power characteristics

3.18 Two extreme wind generation output profiles, diversified and non-diversified, are used to conduct the assessments of the need for transmission capacity driven by wind power. For wind farms spread across very wide geographical areas (i.e. all GB), the diversity effects will be significant, while wind farms in close proximity will be characterized by non-diversified wind generation output profiles. Given that the majority of wind power is to be connected in Scotland we anticipate that the corresponding wind output profile will be between the two extremes. This study used a long-term average wind load factor of 35%. Previous work developed [11] has been based on similar assumptions.

3.19 The variability of wind power output was statistically assessed from the frequency distribution of wind generation, considering annual time series. The frequency distribution of the half hourly wind power output for diversified and non-diversified wind generation output profiles are shown in Figure 4. We can observe that the diversified wind generation profile is less variable, while the non-diversified wind generation profile is more extreme (higher frequencies of extremely high and low outputs).

3.20 Various wind generation output levels (between zero and maximum output) are represented as a multi-state generator characterised by their available capacities and associated probabilities (obtained by an analysis of the wind generation output profiles). The behaviour of the conventional units (expressed by the capacity outage probability table – COPT) of the generation facilities is then statistically combined with wind generation, resulting in a generation system mix (conventional and wind) [9].

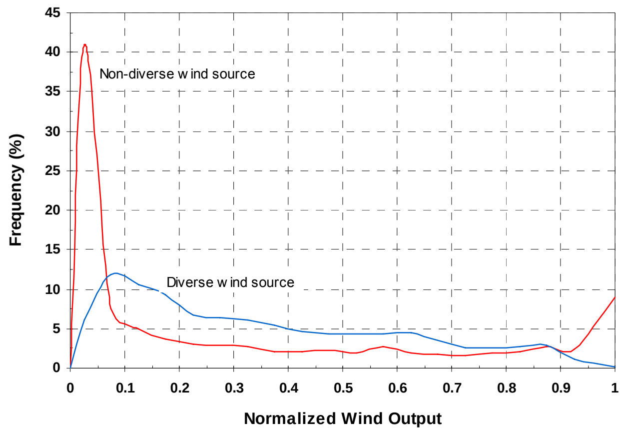

Figure 4 Normalized wind output.

3.3.2 Contribution of wind to adequacy of generation system

3.21 The contribution of wind to security of supply is determined by the ability of wind generation to displace conventional generation capacity. The behaviour of conventional units and wind generation was statistically combined, enabling the risk of peak demand exceeding available generation (LOLP) to be assessed. This analysis was applied to calculate the amount of conventional generation that it is possible to displace with wind generation, while ensuring that the risk of loss of supply is not greater than the 9% (in the combined conventional and wind generation system). The contribution of wind generation to capacity is presented in Figure 5, for various levels of installed wind capacity of different diversity characteristics.

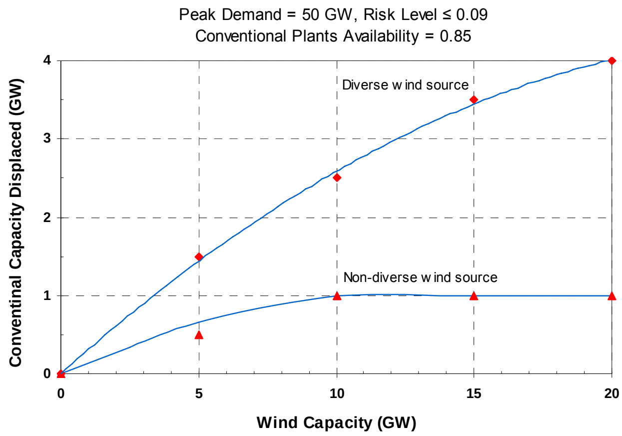

Figure 5 Capacity of conventional plant that can be displaced with wind generation

3.22 Figure 5 shows that at small levels of wind penetration, the capacity value of wind is relatively significant – since 5 GW of wind generation displaces 1.5 GW and 0.5 GW conventional plant considering diversified and non-diversified wind generation output profiles respectively. However, as the capacity of wind generation increases the contribution of wind power to capacity reduces. Previous work developed, [10] and [12] has yielded similar results to these shown in Figure 5.

3.3.3 Wind and transmission capacity

3.23 The presented concepts were expanded to permit the computing of adequate transmission capacity in a system with significant penetration of wind generation. The transmission capacity is designed such that the additional risk pertinent to transmission does not exceed 5%.

3.3.4 Illustration of the methodology

3.24 The methodology is illustrated on a simple two area system: the system under analysis is characterized by 5 GW of peak demand in area A and 45 GW of peak demand in area B. Area A is also characterized by the presence of wind power with an increasing penetration level varying from 0 to 20 GW. Figure 6 and Figure 7, with characteristic V shapes, present the transmission capacity required to connect the two areas for different levels of conventional generation in area A and for various levels of wind generation capacities also in area A, for non-diversified and diversified wind profiles respectively.

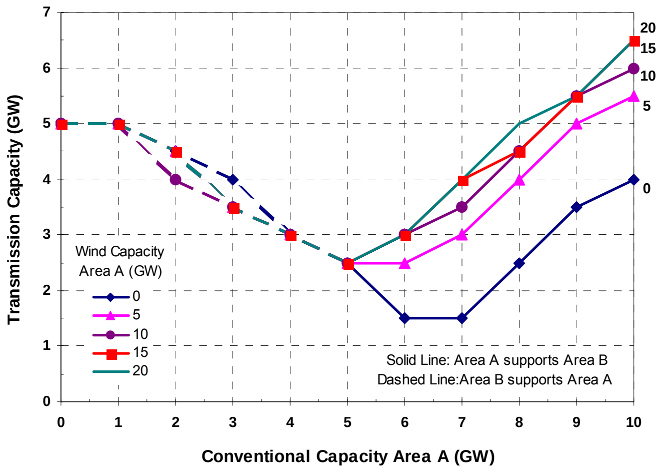

Figure 6 Transmission capacity requirements for a system with wind generation.(non diversified wind)

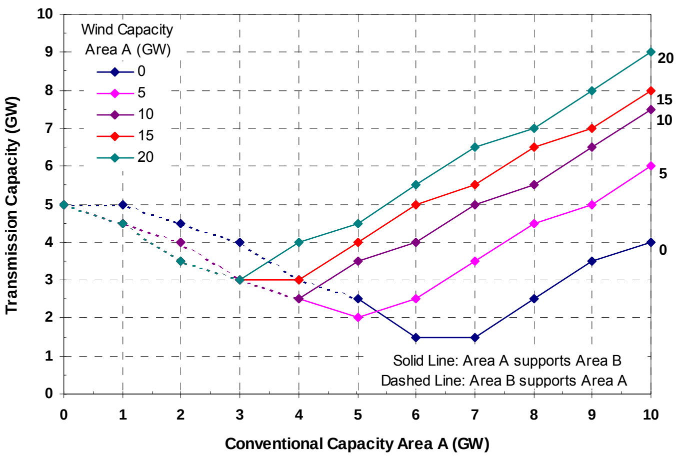

Figure 7 Transmission capacity requirements for a system with wind generation.(diversified wind)

3.25 It can be observed form Figure 6 and Figure 7 that when area A is an importing area (small amount of conventional plant in area A – dashed lines), the presence of wind generation in the system does not substantially change the required transmission capacity requirements. This is because wind power is not a reliable source of supply in the importing area. It is important to note that an area is considered to be an importing area if additional generation in that area reduces the transmission capacity requirement.

3.26 When area A becomes an exporting area, although the presence of wind generation increases the need for transmission, this increase is relatively small compared with the wind capacity installed. For example, in the case that 8 GW of conventional generation is present in system A, the transmission capacity will increase from 2.5 GW for no wind to 4.5 GW or 5.5 GW for 10 GW wind installed capacity with non-diversified and diversified wind profiles respectively. However, the relative increase in transmission capacity reduces with further increases in the level of wind generation. For example, for 15GW of wind in area A (and 8 GW of conventional plant), the transmission capacity should only be 5 GW and 6.5 GW for non-diversified and diversified wind profiles respectively. This also indicates that the capacity value of wind generation decreases as the wind penetration level increases.

3.27 This analysis clearly demonstrates that the scaling factors, that would be appropriate to be used for wind, in the framework of the existing GB SQSS, will depend on the level of penetration of wind and the characteristics of wind power. From a comprehensive sensitivity assessment, based on the information in Figure 6 and Figure 7, we concluded that scaling factors for wind power are between 20-35% for non-diversified and 30-45% for diversified wind (higher values correspond to lower levels of wind generation penetration). Although it may be practical to establish a single value for the scaling factor to be routinely used by network planners, in the subsequent studies we evaluate the contribution that wind generation makes to network investment for a specific set of circumstances.

3.28 Most importantly, this analysis clearly demonstrates that wind generation drives significantly less transmission capacity than conventional generation and that transmission capacity should be shared between wind and conventional generation.

3.3.5 Comparison of the developed methodology with the existing GB SQSS

3.29 In this section we compare the present GB SQSS with the methodology developed. For the purpose of this study we consider the schematic representation of the interconnected transmission system as presented in Figure 8. Area A is characterised by a peak demand of 5 GW and area B by peak demand of 45 GW. Regarding the generation background, the study is performed for different levels of installed conventional generation in each area, and for various levels of installed wind capacity in area A.

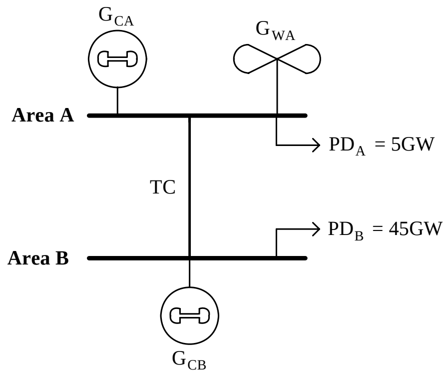

Figure 8 Main interconnected transmission system.

3.30 Figure 9 presents the transmission capacity required on the interconnected transmission system for different levels of installed conventional generation in area A and for 10GW of wind installed capacity also in area A.

3.31 Considering area A as an importing area (transmission capacity represented by dashed line), the GB SQSS would suggest about 2.5 GW less of transmission capacity than the methodology proposed in this report. On the other hand, when area A is an exporting area (transmission capacity represented by solid line) and for 8GW of conventional generation capacity, the GB SQSS suggests 8 GW of transmission capacity, rather than 4.5GW and 6GW (for diversified and non-diversified wind profiles), which indicates significant over-investment.

3.32 For higher levels of penetration these effects are significantly more prominent, resulting in significant transmission over-investment in the case of area A being an exporting area (as is the present situation in Scotland).

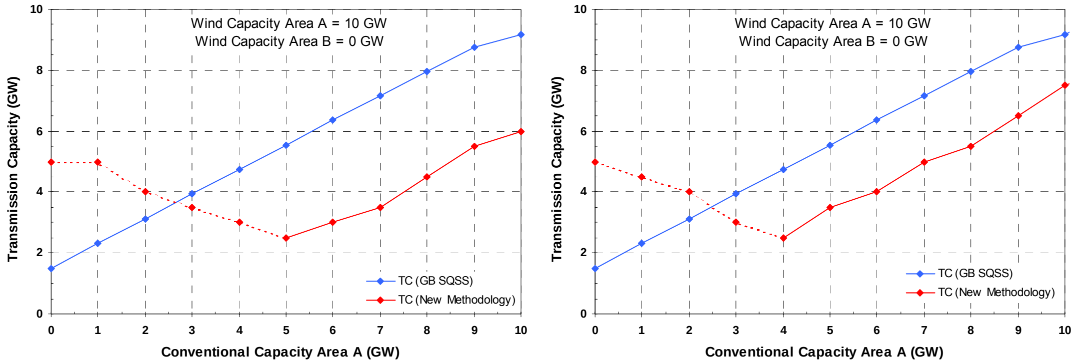

Figure 9 Comparison of the transmission capacity requirements for a system with 10GW of wind connected in area A (non-diversified and diversified wind profiles respectively).

3.33 Clearly, applying unrealistically large scaling factors to wind generation, as used in the present GB SQSS, can lead to under-investment in transmission for importing areas and over-investment in transmission for exporting areas.

3.3.6 Network capacity driven by economics

3.34 Economic considerations may require additional network capacity to be installed to allow efficient utilization of low marginal cost generators, such as wind. By conducting a cost-benefit analysis, decisions taken to reinforce transmission can be justified if the savings in the marginal reduction in out of merit generation costs (marginal cost of constraints) is greater than the marginal transmission network investment cost.

3.35 We have developed an investment optimisation methodology that, through simulation and optimisation of the system operation across an annual time horizon, balances the annual generation costs and annuitised investment costs in order to analyse the need for transmission system reinforcements. For illustrative purposes, this was implemented on a generic GB transmission network model, shown in Figure 10 below. We divided the GB network into a number of areas so that the generic GB transmission system is composed of 15 bus bars. Generation capacities and technologies including forecast peak demand were extracted from the 2006 GB Seven Year Statement.

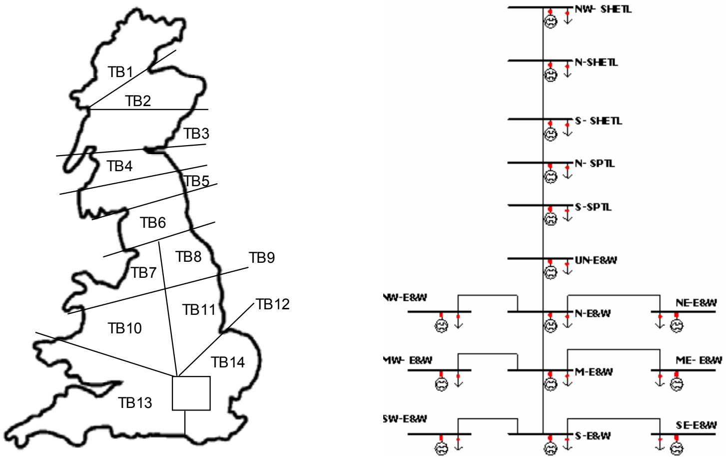

Figure 10 Generic GB transmission system

3.36 By conducting a cost-benefit analysis, decisions taken to reinforce transmission can be justified if the savings in the reduction of out of merit generation costs are larger than the investment cost in the proposed network reinforcement (the transmission cost and the cost of constraints will be the key drivers for decisions associated with network reinforcement)

3.37 We have developed a DC-based investment optimization formulation that balances the annual generation costs and annuitised investment costs, which is described in the following section.

3.3.7 Mathematical Formulation

3.38 The transmission planning problem can be formulated as a Linear Programming (LP) optimization problem as follows:

Minimize:

$$\gamma = \sum_{l=1}^{NB}\left(k_l \cdot F_l^{inv}\right) + \sum_{t=1}^{NP}\left\{\tau^t \sum_{i=1}^{NN}\left(c_{cg,i} \cdot P_{cg,i}^t - c_{wi} \cdot \Delta P_{wi}^t\right)\right\} \quad (1)$$

Subject to:

$$\sum_{i=1}^{NN}(P_{cg,i}^t + \Delta P_{wi}^t) = \sum_{i=1}^{NN}(D_i^t - P_{wavail,i}{}^t) \quad (2)$$

$$-F_l^{inv} \le F_{l,c}{}^t \le F_l^{inv} \quad (3)$$

$$F_{l,c}{}^t = \sum_{i=1}^{NN}\left(\frac{\partial F_{l,c}{}^t}{\partial P_i^t} \cdot (P_{cg,i}^t + P_{w\max,i}^t + \Delta P_{w,i}{}^t - D_i^t)\right) \quad (4)$$

$$P_{cg\min} \le P_{cg}^t \le P_{cg\max} \quad (5)$$

$$0 \le P_{w\max}^{t} + \Delta P_{w}^{t} \le P_{w\max}{}^{t} \qquad (6)$$

3.39 The symbols used in the above equations are defined as follow. NB, NN and NP are the number of branches, nodes and operating scenarios respectively. k_l is the annuitised transmission investment price for circuit l. F_{lc}^{t} and F_l^{inv} are the power flow in period t and the proposed additional capacity for the line l respectively. τ^t is the duration of the demand period t. Superscript t indicates that the value of the variables is a function of t. P_{cg}^{t} and c_{cg}^{t} are the output and the unit cost of generating electricity of conventional generator g at period t respectively. ΔP_w^t and c_w^t are the wind curtailment and the associated unit cost at period t. $P_{w\max,i}^{t}$ is the maximum wind power available at period t and $P_{cg\min}$ and $P_{cg\max}$ are the generator lower and upper limits respectively. D_i^t is the demand at bus i and period t.

3.40 Equation (2) is the system power balance constraint that ensures the power balance between supply and demand. For simplicity, the losses are not considered. The transmission flow constraints for all circuits and generation constraints for all generators including conventional and wind generation are presented in (3)-(6). All constraints must be satisfied in both intact and contingent systems for all operation conditions.

3.41 The optimization problem in (1)-(6) is solved using a standard LP solver [14]. The solution of the problem will include a set of secured generation dispatches (volumes and cost of constraints) and the optimal transmission reinforcement.

3.3.8 Profiling Technique

3.42 In the annual analysis of the operating generation costs, we used typical load profiles for a number of characteristic days to capture the temporal daily and seasonal system load variation (winter, summer and autumn/spring). Different load profiles can are used to represent weekdays and weekends.

3.43 The profiles were further simplified as shown in Figure 11.

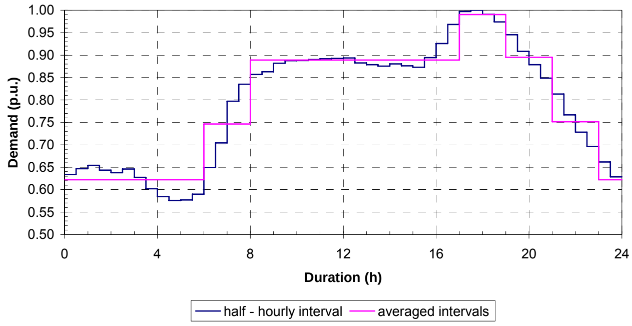

Figure 11 An example of the characteristic winter daily load profile with aggregated intervals.

3.44 For wind modelling, an expected half-hourly annual wind plant output profile was used. For each loading condition, data for wind generation associated with the time interval used for classifying load levels was grouped into 5 equally spaced output levels (covering the outputs between 0% and 100%) according to Figure 12.

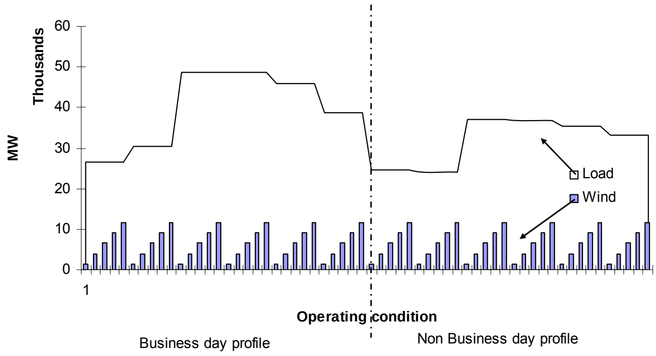

Figure 12 An example of half-hourly load and wind profiles correlation in winter.

Potential problems associated with the application of cost benefit analysis

3.45 Although it is in principle appropriate that a cost-benefit analysis is applied for determining network capacity and investment, this approach relies on *a range of assumptions* that may be contentious, including *future generation technology distributions, fuel costs, projection of future constraint costs and their variations in time and space, network reinforcement cost (that may also vary significantly. The accuracy of the results could significantly depend on the accuracy of the modelling process.*

3.46 However, not only the *values* that would be used in such evolutions but also the *basis* on which these values should be derived is debatable. One of the discussion points is associated with the appropriateness of including generation capacity costs in the overall cost of constraints. It is however well recognised that, theoretically, for the long-term equilibrium of the system and hence the optimal transmission network capacity, *only fuel cost differentials are relevant* as in the long-term the transmission network cannot substitute for generation. Clearly, closures of constrained-on generation in importing areas due to increased transmission capacity will in the long-term need to be accompanied by commissioning new generation in the exporting area (to maintain security of supply). In other words, in a long-term equilibrium position, savings in generation capacity cost in importing areas (achieved by investment in transmission) will be accompanied by additional expenditure on new generation in the exporting areas, if security of supply is to be maintained (clearly, the transmission network does not generate electricity). Assuming that the generation investment costs in both areas are the same[8] increased capacity of transmission between the two areas does not bring any savings associated with generation capacity costs. However, in this respect it is unclear if the present market is cost reflective and able to signal efficient investment in transmission.

3.47 Furthermore, there are questions as to whether and how the short-term imbalance prices should be used as signals for making decisions on long-term transmission investment. Recently, energy prices have been very volatile: after a recent significant increase in gas prices, in the last 6 months wholesale electricity prices have reduced by more than 50%, while the costs of constraints associated with the Scotland – England interconnector have more than doubled over the last 12 months. This volatility clearly complicates greatly investment decisions in transmission given the long life span of network assets.

3.48 Moreover, there are uncertainties about future development of the market itself that may need to be considered: for example, procedures and the basis on which imbalance prices are calculated have changed on a number of occasions since the NETA was introduced. There is also a debate over whether the present market, which does not explicitly recognise generation capacity costs (no capacity payment), will, with significant penetration of wind power, be able to sufficiently reward capacity of marginal conventional plant that will need to operate at even lower load factors but will be essential to maintain security.

[8] In fact, from the generation capacity cost perspective, it is possible that it may be significantly cheaper to keep an existing constrained on plant on the system rather than build new plant in the exporting area (in addition to investment in transmission necessary to accommodate the output of the new plant). In this case, increasing transmission capacity would be undesirable.

3.49 In addition, there are massive uncertainties associated with the conversion of applications for connecting wind power into actual projects due to various reasons (particularly planning issues). Historical experience would suggest that only around 50% applications will be converted into connections.

3.50 It is clear that these issues are very significant and hence that the application of the cost-benefit analysis in practice is often very difficult and controversial[9]. We therefore propose that the existing GB SQSS should be extended to include wind power using the philosophy of the present standard, given that it requires significantly less data and can deliver considerably more robust solutions. This standard would constitute *a minimum standard*[10] while leaving the opportunity to increase the transmission capacity above the minimum if it could be justified on the basis of cost-benefit assessment

3.4 Comparisons between security and economics driven investment

3.51 In order to demonstrate the application of the proposed methodologies and to discuss the impact of wind power on the investment and pricing of transmission, a number of case studies were carried out using a simplified generic GB transmission system model.

3.52 As a base case, the capacity of the GB transmission system was determined by excluding wind generation. Then 10 GW of wind power was added to Scotland and 3 GW was added to the South East of England. Transmission network capacities associated with major transmission boundaries, obtained from the three planning methodologies, i.e. security driven network capacity, economics driven network capacity and the capacity that the present GB SQSS would suggest, are presented in TABLE III. Given the concentration of wind power in relatively limited geographical areas, we used non-diversified wind profiles in this analysis. This is in line with the recent analysis carried out by Oswald Consultancy for the Renewable Energy Foundation: "25GW of distributed wind on the UK electricity system" that demonstrated that the correlation between peak demand and wind output was weak.

[9] Problems with user driven transmission investment approach through the present concept of Transmission Entry Capacity are discussed later.

[10] There will be however opportunities to build more transmission if it could be justified on the basis of cost benefit assessment

TABLE III

COMPARISON OF TRANSMISSION CAPACITIES ASSOCIATED WITH KEY SYSTEM BOUNDARIES FOR 10GW WIND POWER IN SCOTLAND AND 3GW IN ENGLAND FOR THE THREE APPROACHES ANALYSED.

From	To	Security	Economics	GB SQSS
NW-SHETL	N-SHETL	2100	2437	2561
N-SHETL	S-SHETL	3500	3571	4439
S-SHETL	N-SPTL	3300	4110	4904
N-SPTL	S-SPTL	4100	3564	5438
S-SPTL	UN-E&W	4300	5357	7667
UN-E&W	N-E&W	4700	4935	7514
NW-E&W	N-E&W	2400	1942	2424
NE-E&W	N-E&W	5600	2218	4895
N-E&W	M-E&W	8700	7870	10674
MW-E&W	M-E&W	6800	4798	6848
ME-E&W	M-E&W	5400	4459	4869
M-E&W	S-E&W	8100	8434	9206
SW-E&W	S-E&W	3400	2781	4360
SE-E&W	S-E&W	5100	1438	4766

3.53 When 10 GW of wind are added in Scotland, investment will be required to reinforce the network due to both security and economic reasons, assuming that no conventional plant will be decommissioned in Scotland (the worst case scenario). We also assumed that conventional generators in Scotland are more efficient (and hence characterised by lower marginal cost) than generators in England. These assumptions will tend to increase the need for transmission between Scotland and England.

3.54 We observe that, for example, the network capacity across the boundary between Scotland and England should increase to 4.3 GW, considering security, 5.4 GW, considering economics[11], and 7.6 GW, if the present GB SQSS is applied. However, when the capacity of transmission is driven by wind power (e.g. Beauly-Denny line), the cost benefit analysis carried out in this report supports the GB SQSS results.

[11] In this study, the average constraint cost associated with transmission between Scotland and England is about £15/MWh.

3.55 It is important to point out that the total installed capacity of generation in Scotland in these cases reaches 19.5 GW (conventional and wind), while the peak of the local load is about 6.5 GW. This result clearly demonstrates that is not appropriate to invest in transmission in order to be able to accommodate simultaneous peak outputs from both conventional and wind generation. Instead, *the capacity of transmission should be shared between conventional generation and wind*. In other words, on windy days the capacity of transmission corridor between South of SPTL (S-SPTL) and Upper North of England and Wales (UN-E&W) is primarily used to transport wind power, while on non-windy days, this capacity would be used to export energy from conventional plant. The results also show that for security reasons, 3 GW wind installed in the South East of England will not reduce the transmission capacity needed. The table also shows for the boundaries between Scotland and England that the present GB SQSS would considerably over-estimate the need for transmission capacity.

4. Pricing of Transmission Network Capacity

4.1 The above analysis clearly demonstrates that wind generation drives less transmission capacity than conventional generation and that wind and conventional generation should share transmission network capacity. This has further important implications and requires an investigation into the appropriateness of the existing network charging mechanisms. The present methodology for the evaluation of transmission network use of system charges (TNUoS charges) is not consistent with the network investment planning process, i.e. all generation is charged the same amount irrespective of the need it imposes on the network investment. In other words, the present TNUoS is not cost reflective and necessary modifications have yet to be made to achieve the consistency between network investment and network pricing[12].

4.2 We have therefore examined a possible cost reflective investment, within the present TNUoS framework, that is based transmission pricing methodologies which recognise the distinct contribution of individual generators to network costs. The results demonstrate that wind generation would tend to pay lower TNUoS charges.

4.3 In this section, the corresponding transmission network pricing mechanisms that are applicable to both conventional and variable generation are presented. A case study is also presented on a simplified GB transmission network. The results presented in Table IV are for the cases of 10 GW of wind generation in Scotland and 3 GW of wind generation in England. Both pricing methodologies result in location specific charges. As expected, generators in the North will drive the cost of transmission and hence should be charged, while generators in the South will be rewarded, as they contribute to the reduction transmission capacity.

4.4 Two pricing methodologies that are broadly consistent with the present TNUoS framework were examined: first, based on the impact that generation has on security driven network capacity, and second, based on the impact that generation and demand have on network capacity driven by economics.

[12] Although National Grid uses different scaling factors for wind and conventional generation, which implies that wind and conventional plant drive different levels of transmission investment, this is inconsistent with their TNUoS charging mechanism that does not differentiate between wind and conventional plant (National Grid, The treatment of intermittent generation in the GB Charging Methodology, August 2006)

4.5 Regarding the pricing based on security considerations, we consider single peak demand conditions. When determining the impact that individual generation technologies have on network investment, we apply different scaling factors for conventional and wind as appropriate.

4.6 We have also calculated efficient network prices that are consistent with the cost-benefit based transmission investment methodology. In this approach, we examine the annual flows on the economically optimal transmission network (that optimally balances the marginal transmission investment cost and the marginal cost of constraints). For each transmission circuit, we identify the periods in which the network flow equals the capacity of the circuit. During these periods, the TNUoS charges are different from zero and we use conventional sensitivity analysis to determine the marginal contribution of each network user to the peak flow in each of the circuits. On the other hand, in periods when the power flow through a circuit is lower than the corresponding circuit capacity, TNUoS charge associated with this circuit is zero (as the transmission cost of a marginal increase in the circuit utilisation is zero). This approach is fully consistent with the economic efficiency and cost reflectivity principles and requirements. In order to be able to compare the two sets of charges (security based and economics based), we have finally expressed the inherently time-of-use varying network prices that are consistent with the cost-benefit based transmission investment planning, in terms of a single annual capacity-based charge[13].

[13] Although the details are not presented in this report, both of the transmission pricing methodologies recover fully transmission cost.

TABLE IV

TRANSMISSION CHARGES (£/KW/YEAR)

Nodes	Charges based on security		Charges based on cost-benefit	
	Wind Generation	Conventional Generation	Wind Generation	Conventional Generation
NW-SHETL	9.07	41.53	17.90	26.66
N-SHETL	7.10	37.31	15.46	14.77
S-SHETL	5.81	33.99	13.22	27.89
N-SPTL	0	24.53	0	12.22
S-SPTL	2.09	21.78	5.87	13.40
UN-E&W	0	16.20	0	5.27
NW-E&W	0	2.96	0	6.45
NE-E&W	0	8.43	0	2.99
MW-E&W	0	-2.94	0	-9.18
ME-E&W	0	3.35	0	0.73
SW-E&W	0	-20.41	0	-12.18
SE-E&W	0.51	-5.11	-3.93	-3.92
S-E&W	0	-9.59	0	-1.37

4.7 The results in TABLE IV demonstrate that the cost reflective charges for wind, when the transmission investment is driven by security rather than economics, are always less than the charges for conventional generators in the exporting area (Scotland and North of England). However, in areas dominated by wind power, where the transmission capacity in driven by wind network charges for wind generation may be larger that these for conventional generation. Furthermore, in importing areas, where wind generation does not practically contribute to maintaining system security (i.e. wind generation cannot displace transmission capacity), it does not get rewarded. In this example, wind generation in the South East of England will still need to pay transmission charges while conventional generation at the same location gets paid.

4.8 The results of the allocation of transmission network costs based on economics show that in most cases wind generation should pay less than conventional generation. However, in areas where wind generation dominates conventional generation (i.e. transmission is built to accommodate high wind penetration levels) then wind charges are higher than those of conventional generation. The results also show that in the South, wind generation gets higher rewards than the conventional peak plant due to the higher contribution of wind energy when compared with the peak plant during peak load.

5. Inconsistency of transmission Access, Investment and Pricing arrangements in the UK

5.1 Background

5.1 One of the consequences of the deregulation of the electricity supply industry has been the separation of generation from transmission activities. This separation is indeed frequently considered indispensable to achieve open and non-discriminatory access to the energy market. In this environment, pricing of transmission becomes the key to achieving both efficient operation and least-cost system development of the entire system. Coordination of investment in generation and transmission, which are now operated as separate entities, is to be achieved through efficient network pricing mechanisms.

5.2 This development has opened a debate into the need to restructure the framework for investment and pricing of the transmission network. This restructuring can be taken along two, complementary directions: (i) location-specific short-run marginal cost pricing of transmission coupled with financial transmission rights designed to deliver both user driven transmission investments and efficient pricing of both short and long-term access and (ii) transmission investments based on various combinations of different forms of central planning, regulatory incentives and network user commitments, with network pricing based on long-term marginal transmission investment cost.

5.3 Both of these approaches to investment and pricing should ideally deliver the same transmission network investment assuming that perfect knowledge of the future was available. This is a consequence of the well known theoretical optimum in which the long-run marginal cost is equal to short-run marginal cost.

5.4 The second approach established in the UK starts from the premise that the transmission network is inherently a monopoly and therefore needs to be regulated. The key responsibility of the regulator is to determine the revenue for transmission owners and set out an incentive regime that encourages efficient transmission operation and expansion.

5.5 The questions of how the market and regulatory environment should evolve and be used for determining network capacity requirements in systems with different forms and technologies of largely distributed generation and of what commercial framework will need to be developed to support cost effective integration of DG into the GB electricity system are rapidly increasing in their importance due to high interest in wind power. Although the UK has made a very significant progress in developments associated with electricity market arrangements in general including the particular question of grid integration (UK is a world leader in this field), modifications to the present technical and commercial framework are urgently required and may involve some quite radical changes that would need to be implemented quickly in order to avoid significant delays in connecting renewable generation.

5.6 However, the issue is a very complex one because it includes both regulatory and market aspects. The regulatory aspects of transmission are important as the electricity transmission function exhibits monopolistic features that require regulatory involvement, but there are also growing pressures to introduce elements of market and competition in access to and investment in transmission, i.e. to introduce a market based decision making process by devolving the responsibilities from the regulator to the users of the network.

5.7 In GB, generators are allocated (almost) firm access rights on the basis of the amount of the access purchased (Transmission Entry Capacity), and they are then compensated if the network is unable to accommodate their power outputs. The constraint costs are recovered by charging all market participants uniformly[14]. The cost of access rights that a particular network user is exposed to should ideally be determined by the long-term marginal transmission investment cost imposed by *that* user. In principle, the TNUoS framework was set out to deliver this. Charges are location specific so that users that reduce the demand for transmission investments (generators that are located in demand dominated areas) are rewarded while users that impose the need for transmission investment (generators that are located away from the load centres) are charged[15].

5.8 Transmission network investment, access and pricing should be consistent if the overall objectives of economy and efficiency in both the short and long-term are to be achieved. The inconsistency among the three aspects of the transmission arrangements in the present GB framework is one of the major concerns regarding the cost effective integration of wind power in the GB electricity system.

[14] Historically, due to relatively low cost of constraints this has been considered acceptable. However, this may need to be reviewed in the future.

[15] It is important to note that only a fraction of the transmission cost is allocated on a location specific basis, while the majority of the cost is uniformly spread among the network users. This weakens the signals regarding future locations of generation and loads. Furthermore, although demand and generation have equal and opposite effect on network operation and development, the charging regime discriminate between demand and generation. Demand charges are always positive and demand customers contribute significantly more to the overall transmission revenue than generation customers. This may become a problem in the future with significant penetration of distributed generation of different generation technologies. However a detailed discussion of the (in) appropriateness of these features of the current TNUoS regime is not the subject of this report.

5.2 Inadequacy of transmission access arrangements in GB

5.9 The concept of Transmission Entry Capacity (TEC) should enable users to express their choice regarding the long-term transmission network access they wish to purchase. This access right entitles the holders to compensation if the transmission capacity is not available in the short-term.

5.10 Although this is an attractive concept in principle, the key problem of its present implementation and interpretation is in the lack of consistency with the transmission investment process and transmission network pricing.

5.2.2 Inconsistency of TEC and transmission investment

5.11 The mechanism of translating TEC associated with individual network users into transmission investment is unclear. Although TEC could be used to design and cost the capacity associated with the connection to the main system, we demonstrated that TEC associated with an individual generator cannot be directly linked with the need for capacity that that generator imposes on the main interconnected transmission network. Different generation technologies drive different investment of the main transmission network and this is not directly related to the value of TEC as defined at present. This is critically important as the absence of a link between TEC and transmission investment cost means that an efficient price for TEC cannot be transparently determined. In other words, as TEC cannot be directly linked with the need for transmission investment that the user imposes, there is no mechanism that would allow efficient and transparent valuation of TEC. Although in systems with conventional generation only, the concept of TEC could provide a reasonable compromise (as generators could be credibly assumed to be all running at their maximum during peak condition), in a system in which electricity is supplied by different generation technologies that impose different requirements on the transmission network investment, the concept of TEC has significantly less meaning.

5.12 To illustrate this point, we present a well-known example of demand (and this then can be extended to generation). We consider the amount of network capacity imposed by a single household and that by a large group of households. Peak demand of an individual, single household is on average about 10kW. This is used to design the service cable that connects the household and the distribution network. If asked, individual households would declare 10kW for exit network capacity (given that the value of load curtailment is significantly higher than the network investment costs, i.e. network charges). However, when the distribution network operators design a primary substation (33kV/11kV) that may supply several thousand households, the average contribution of a single household to the peak loading of this substation is in the order of just 1 kW. In this situation, although the consumer required 10kW of firm access (which could be used to design the service cable), the contribution of this consumer to the design of circuits upstream can be significantly smaller than the value of exit capacity due to diversity effects. This means that the value of firm access right is not relevant for investment cost of the interconnected system and hence should not be used to determine the price of access to the interconnected network.

5.13 Similarly, the value of TEC is not directly relevant for the design of transmission networks in a system with mixes of conventional and intermittent generation. On the hand, if the values of TEC of the individual generators are simply added together this would clearly lead to over-investment in the transmission network[16].

5.14 The concept of TEC, in its present format, clearly does not provide the basis for transmission reinforcement and hence should not be used as the indicator of user commitment for future network investment.

5.2.3 Inconsistency of TEC and TNUoS charging methodology

5.15 In accordance with the present transmission charging methodology, the value of TEC is used for pricing of transmission network usage. However, given that TEC associated with a (renewable) generator is not directly relevant for determining the impact that the user makes on long term marginal transmission investment cost, using TEC for pricing is clearly not cost reflective. As we illustrated, the efficient amount of transmission capacity needed between Scotland and England would be such that conventional and wind generation share the network capacity and their individual TEC requirements are not related to this capacity and their individual contributions to the need for investment, and hence TEC should not be used in network pricing. Again, the concept of TEC has little significance in the context of network pricing in systems with mixes of generation technologies (conventional and renewables).

[16] Another (extreme) example would be the case of PV generation. If the network design is driven by peak demand condition in winter, although PV generation may require TEC equal to installed capacity, this generation would have no impact on transmission network investment and hence the efficient price for TEC is zero. Present system does not link price of TEC and the impact on investment cost and is hence inefficient.

5.2.4 TEC and inefficiency of generation system operation

5.16 Generators that purchase a certain amount of TEC that is lower than the installed capacity of their generation would be prevented from generating in excess of the TEC purchased, irrespective of whether the network is congested or not. This is clearly inefficient as the users are unnecessarily prevented from accessing the transmission network (and hence the energy market) when the short-term marginal cost of using that transmission capacity is minimal (close to zero). This will require the operation of higher cost generation and in turn it will lead to an increase in electricity prices.

5.2.5 TEC and inefficiency of transmission investment

5.17 The process of converting TEC into investment capacity decisions is not clear. Although it may be justified in most cases to use TEC to determine the capacity of the connection between the generating station and the main transmission system (so that the full output can be injected into the transmission network), in the context of assessing the need for transmission capacity between large areas the present approach does not adequately take into account the effect of diversity, which is, as discussed above, fundamental to the efficient development of transmission network. If the values of TEC of the individual generators are simply added together, this will clearly lead to over-investment.

5.18 Furthermore, if the amount of TEC issued to transmission network users matches the available transmission capacity, this would be clearly inefficient, because a constraint free transmission network is uneconomic. An economically efficient transmission system should be optimally constrained rather than operate in a constraint free mode.

6. Conclusions

6.1 In addition to the various administrative issues associated with the development of wind power projects, insufficient GB transmission network capacity to absorb the outputs of both the existing and new generation is the key barrier in the context of grid integration of DG in the short and medium-term.

6.2 We point out that wind power is significantly different from conventional generation and that the present technical, commercial and regulatory framework associated with transmission access, that has been designed for a system with conventional generation only, will need to be modified. In its present form, it is unable to facilitate cost effective integration of different technologies of DG (wind in particular) into the GB electricity system.

6.3 At present, there is no consensus regarding the methodology for determining the need for transmission capacity in systems that include non-conventional generation technologies, such as wind. However, all recent UK work in this area suggests that wind generation drives less transmission investment than conventional generation and that wind and conventional generation should share transmission capacity. When determining the need for transmission capacity, the scaling factor used in the GBSQSS for conventional plant is 83%, while various lower value scaling factors are proposed for wind generation: 60% by National Grid, while SKM work indicates significantly lower figure of about 20%. Our rigorous approach demonstrated that the scaling factors appropriate to be applied to wind should be in the region of between 30% and 40%.

6.4 We propose that the GB SQSS should be reviewed and updated to consistently include wind power, following the principles on which the standard was originally developed (as described in the report). Such an update of the transmission planning standard that is based on security requirements would constitute a minimum transmission standard. There will be however opportunities to build more or less transmission if this could be justified on the basis of a cost-benefit assessment.

6.5 We demonstrate that wind generation tends to drive less transmission investment than conventional generation. We also show that wind and conventional generation should share transmission capacity and hence avoid unnecessary and sub-optimal transmission network reinforcements. However, the current approach to access and pricing does not support this efficient operation of a system that contains a mix of conventional and wind generation.

6.6 As the results of the investment studies conclusively demonstrate that wind generation drives less transmission investment, we evaluated cost reflective TNUoS charges for wind and conventional generation and demonstrate that wind generation should pay lower charges. In other words, if a non-discriminatory access to transmission network is to be established, TNUoS charges would need to discriminate between generation technologies.

6.7 We have identified a number of weaknesses in the application of the concept of TEC in systems with wind power. Our analysis suggests that the concept of TEC does not reflect a need for investment and should not therefore be used for network pricing. In addition we point out that the concept of TEC can lead to inefficiencies in both system operation and network investment.

Possible ways forward

6.8 There are a number of possible approaches to address the inconsistencies in the present transmission network access, investment and pricing arrangements. Given the complexity of these arrangements it would be appropriate that a coordinated debate with all interested parties is held through appropriate forums and corresponding consultation processes. In principle, we have identified two extreme positions that could be considered:

Administered arrangement: all users could be given firm access to the transmission network as the present concept of TEC is not very relevant to design and to pricing of the main interconnected network in systems with mixes of different generation technologies. The transmission network could be designed in accordance with an appropriately updated GB SQSS that facilitates sharing of transmission capacity between generators of different technologies. TNUoS charging methodology could be modified to achieve cost reflectivity, as discussed in this report. Costs of network constraints could be administered. The volumes and costs of constraints could to be closely monitored and the need for investment in transmission periodically reviewed.

Market based access arrangement: develop a market for transmission access with fully tradable transmission access rights that reflect the time varying (probably half hourly) and location specific short-term marginal cost of network capacity, that can be hedged by long-term, location specific (and possibly time varying) products, efficiently priced at the marginal investment cost of transmission. This approach will require the question of the reallocation of transmission access rights of incumbents to be resolved. Clearly, if the incumbent generators continue to hold transmission rights in Scotland, the market value of these rights (particularly during high wind regimes when the network become congested) could reach the value of Renewable Obligation Certificates (ROCs), in which case the conventional generation, rather than wind generation would benefit from ROC-related income. In this context, for example, it is worth pointing out that, Cockenzie, which is one of the least efficient large generating stations in the entire GB system, currently holds 1000MW of transmission access right and prevents the connection of zero marginal cost, CO_2 free wind generation.

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