Implications of intermittency and transmission constraints for renewables deployment

Karsten Neuhoff, Jim Cust and Kim Keats

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1 Introduction

In order to meet its Kyoto objectives and accelerate the transition to a low-carbon economy, the UK has set itself the long-term target of cutting carbon emissions by 60% by 2050. One key aspect in the decarbonisation of the UK economy involves a move towards low-carbon electricity generation. Given increased emissions pressure from other sectors of the economy, most notably road transport and aviation, it is likely that more stringent cuts will be needed in the electricity sector. To push forward this structural adjustment, the UK government has set itself the target of providing 15% of electricity needs from renewable energy sources by 2015 and an aspirational target of 20% by 2020. Most renewable technologies are characterised by their intermittency and regional variation. In this chapter we explore the implications at the example of wind power, which is expected to provide large fractions of renewable electricity over the coming years (see the chapter by Elders et. al.). We aim to understand some of the implication of this, or more ambitious targets, for the UK power system.

To structure the analysis we use an Investment Planning Model (IPM) that depicts operation and evolution of the power system. Like any numerical model, our approach only allows us to provide meaningful insights relating to a limited set of questions. Therefore in this paper we do not allow for the construction of technologies other than gas turbines and on-shore wind turbines. We also assume that all market participants require the same real rate of return of 11% - and thus ignore potentially differing regulatory, technology and price risk between technologies. We list some cost estimates resulting from other models that complement our analysis. In order to explore the issues relating to a power system with high levels of wind energy we model scenarios where 20% and 40% of total energy is delivered by wind power. We achieve these levels of investment by 2020 by choosing capital costs for wind power at which these targets are met.

A key question posed by the expansion of wind-powered electricity generation in the UK is one of location. This raises three important challenges. First, the regions

[1] We would like to thank ICF International for use of the IPM model, Dash Optimisation for use of the Xpress solver, and Graham Sinden at ECI Oxford for his assistance with the wind energy data. Financial support from the UK research councils project SupergenFuture Nets is gratefully acknowledged. Contact: Karsten.Neuhoff@econ.cam.ac.uk, Faculty of Economics, Cambridge University, Sidgwick Avenue, Cambridge CB3 9DE.

where the resource potential is greatest - Scotland, the north and south-west of England - have relatively low electricity demand. In contrast the key load centres of central and south-eastern England have less wind resource (Grubb *et al* 2006). We therefore model the capacity constraints on transmission lines between regions explicitly to see how they affect the optimal location of wind turbines and to what extent additional transmission capacity expansion is warranted. Second, output of wind turbines is intermittent. However, the volatility of the aggregate output of wind turbines can be reduced if they are distributed over a larger area. As we are using hourly wind output data for each region, our model endogenously calculates the value of regional diversification. Third, regional transmission constraints, scarcity of build sites, and socio-political tensions around new build make the large-scale deployment of wind turbines a challenge (Butler and Neuhoff (2005) and Devine-Wright (2005)). Thus we set regional build constraints and explore the cost reductions that can be achieved for the system if these constraints are relaxed. We thus can quantify the benefit of improving public acceptability or planning processes.

For this modelling we cooperated with ICF International to use their existing Integrated Planning Model (Neuhoff *et al* 2005) and database of the GB power system. The model assumes perfect foresight and simultaneously optimises investment decisions in power stations and their subsequent operation. Thus it determines the volume and technology of investment in every five year period and hourly dispatch of the system within that period. We expanded the model to capture the temporal and spatial characteristics of wind output using historical data for individual regions. Thus we can simulate the evolution of the UK electricity system with the gradual penetration of on-shore wind power. We do not explicitly model the deployment of offshore wind power due to limited data availability. We have verified the robustness of the approach and sensitivities to various input parameters in Neuhoff et al. (2005). Here we take a base case using IEA price and cost data and change the penetration of wind power by changing the assumptions about wind turbine construction and connection costs. This allows us to assess the impact and additional system costs of greater utilisation of the wind resource.

Our modelling work focuses on the impact of a variable energy source such as wind, as compared with more conventional generation technologies such as combined-cycle gas turbines. As such, our work does not directly address other power engineering issues that may impose additional constraints we cannot directly account for, such as fault ride through, system inertia and spinning reserve. Also, whilst ramping constraints are not included in our modelling work we refer to separate modelling to estimate the additional impact (Strbac 2002; Muesgens and Neuhoff 2005; Gross *et al* 2006). Our dataset uses onshore wind observations and as such cannot capture offshore planning decisions. While currently off-shore connection and construction costs are higher, cost reductions through learning by doing and the better off-shore wind resource might compensate for these effects (L.E.K. Consulting 2006). While the basic insights relating to locational choices and congestion management do also apply to off-shore wind, further modelling with the appropriate representation of off-shore wind pattern is required to allow for quantitative insights. Whilst our model does not impose grid connection charges within the regions, in two scenarios we increase the construction costs for wind turbines, which could reflect the impacts of increasing connection charges.

The modelling of optimal investment in new energy generation was first attempted in France during the 1950's (see Bessiere, (1970). Uncertainty was introduced in models relating to plant availability by Baleriaux et al. (1967). To cope with the increasing size of models Blooms (1983) reformulated the problem to use a Generalized benders decomposition thus allowing for parallel processing. If we were to introduce additional detail in our simulations, we would likely have to follow this approach. In the recent literature, DeCarolis and Keith (2006) use five years of hourly demand and wind production pattern to calculate optimal system configuration. This US model however, is restricted to five production sites, one demand site and only calculates a static long-term equilibrium that does not address the transition from today's energy system.

2. The Model

The Integrated Planning Model from ICF International is an investment planning model that uses a linear programming formulation to select investment options and to dispatch generating and load management resources to meet overall electric demand today and on an ongoing basis over the chosen planning horizon. We customised the model to more accurately model wind power in the investment choices. The Xpress linear programme solver from Dash Optimisation was used to find the optimal solution[2].

We divided the GB into seven transmission constrained regions as shown in Figure 1. This is the same approach used by the National Grid in its Seven Year Statement (NGC 2006). We will refer to the GB regions by the following abbreviations hereafter: SCO- Scotland, UNO- Upper North, NOR- North, MID- Midlands, CEN- Central, SWE- South West and EST- Estuary. While the IPM could be used to model the transmission system at a more disaggregated level, we use this simplified representation as we could not find a robust data representation at lower level of aggregation.

[2] http://www.dashoptimization.com/

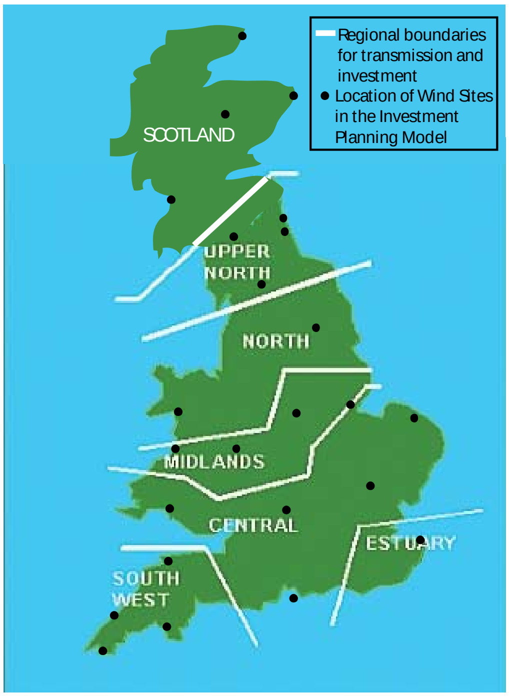

Figure 1 - Wind Measurement Site Location and Regional Boundaries

Demand for electricity was assumed to grow from 363 TWh in 2005 to 432 TWh in 2020 with the peak growing from 60.7 GW to 72.3 GW over the same time horizon. Both annual and peak demand were assumed to grow at the same rate: just under 1.5% per year up to 2010 falling to 1.0% for the following decade. The distribution of demand across the dispatch regions was kept constant as follows:

	Scotland SCO	**Upper North UNO**	**North NOR**	**Midlands MID**	**Central CEN**	**Estuary EST**	**South West SW**
Demand share	9.8%	5.3%	21.4%	13.3%	40.6%	5.2%	4.4%

Table 1: Distribution of Demand Across Dispatch Regions

Our raw wind data is based upon observed hourly wind speed measurements taken at 24 different onshore sites around the UK for 1995 (UK Met Office and British Atmospheric Data Centre). It is generally accepted that wind speeds at a single location can be modelled as a Weibull distribution[3]. We did attempt to fit a multidimensional Weibull distribution to our sample but decided to use the actual data instead. Due to computational constraints, we used the wind speed data for a single day as representative for all seven days in a given week for all our weeks in the year.

We used the wind data to model wind power output from a hypothetical array of wind turbines located in each of our eight geographical regions. As the wind speed measurements are for ground level our data has been corrected according to power

[3] http://www.windpower.org/en/tour/wres/weibull.htm

transform data for a Nordex N80 wind turbine (Nordex 2004). To confirm that this sampling was not adding any bias, we used a bootstrapping approach, using wind data from different weekdays, and confirmed that the results were robust to different choices of wind input data (Neuhoff et al. 2005).

Figure 2 illustrates the full wind load hours per region in each modelled year. The regions SCO and SWE have the highest wind load hours yet relatively low demand profiles relative to CEN, MID and EST regions. In turn, these high demand regions have relatively poor wind resources. This feature presents challenges regarding the large-scale deployment of wind power in the GB, particularly in relation to transmission constraints and locational decisions.

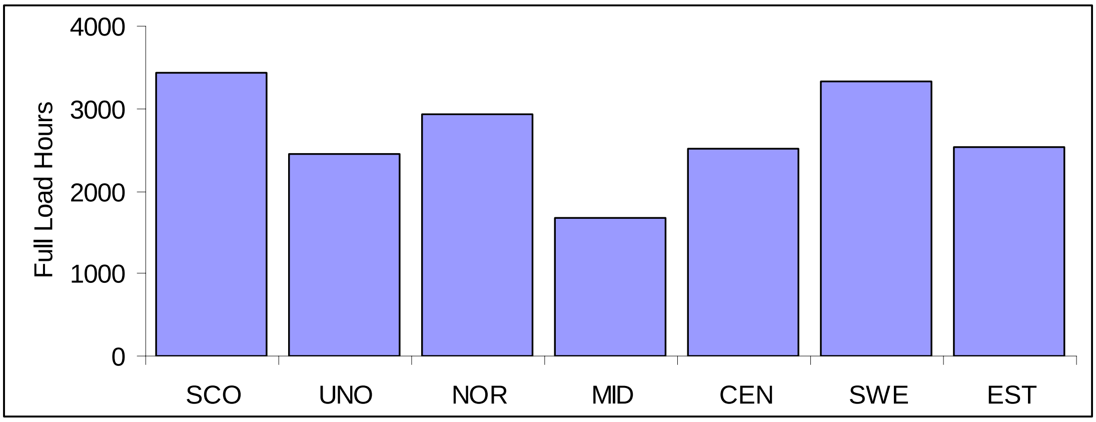

Figure 2 - Wind power full load hours by region, relative to 8760 hours per year

For existing power stations we used the database developed by ICF International. Nuclear power stations retire as anticipated in the seven-year statement of NGT. The closure of coal power stations, partially induced by the Large Combustion Plant directive, is calculated in a separate model run and set as an exogenous decision in our calculations.

3. Model Scenarios

The objective of our modelling is to investigate the impacts of and challenges posed by different penetration levels of wind power to 2020 in the GB electricity system. The level of wind power penetration can vary with either changes in fuel prices for conventional plants, CO_2 prices, changes in the capital cost of new wind power or the application of constraints upon wind power. Table 2 shows the main assumptions for investment for new power stations, fuel costs and prices of CO_2 allowances. All numbers are quoted in 2005 prices. Our model incorporates three options to build new power stations. For baseload operation, we allow for the construction of new combined cycle gas turbines (CCGT). For investment in peaking capacity, open cycle gas turbines (OCGT) are modelled as they offer the cheapest capital costs.

	Investment Costs					Fuel Costs		EU ETS
	Gas		Wind					
	CCGT	OCGT	MARKAL reference	20%*	40%*	CCGT	Coal	CO_2
	(€/kW)					(€/mmbtu)	(€/tonne)	(€/tCO2)
2005-2009	580	370	800	1350	750	4.68	51.73	20
2010-2014	550	350	610	1185	560	4. 00	31.61	20
2015-2019	520	330	575	1150	525	4.14	31.61	20
2020-2024	500	320	540	1115	490	4.30	31.61	20

Table 2 Baseline assumptions. Wind costs are varied to reflect subsidies/taxes calibrated for target penetration, *Investment cost assumptions in alternative wind penetration scenarios.

With regards to wind turbines, we assume the same investment cost for both on and off-shore wind turbine costs in all regions. Locations are only differentiated by different availability of wind and their transmission links to other regions. Our investment costs are based on those utilised by the MARKAL modelling of DTI in the 2003 Energy Review[4]. However, we also allow for other scenarios. The first labelled "20%" above represents the cost profile for wind to achieve 20% of demand by 2020. In this case costs, are higher than the DTI reference case. A second alternative, based on achieving a 40% penetration for wind, assumes that investment costs are lower than the DTI reference case.

The costs of new power plants are assumed to fall due to learning-by-doing effects. Learning-by-doing effects link the cost reductions to cumulative installed capacity. However, as we assume that the UK constitutes only a small fraction of the global market we assume exogenous cost reductions, at a rate of 2.5% per annum in period 2005-2010 and 0.5% per annum hereafter[5].We assume that the lifespan of the wind turbines is 25 years. The levelised cost of capital for all technologies and the modelling discount rate is set at a real discount rate of 11%. We also assume that demand side response becomes available at 1000€/MWh. This is a simplified representation of the various different types of industrial and in the future also private sector responses that we can envisage. As better data on these options becomes available the model can be easily expended to capture the different options with their specific contributions. For the time being we do not restrict the maximum amount of demand side response as in all cases less than 1% of total demand is provided by demand side response in any hour at any time.

The European Union's Emission Trading System (ETS) requires power stations to present CO_2 allowances for each tonne of CO_2 they are emitting. While in the first

[4] For fuel costs, current coal and natural gas prices are taken from DTI Quarterly Energy Prices, Table 3.2.1. Long-term coal and gas price assumptions are drawn from (IEA 2005b)Capital costs decreases for onshore wind turbines and CCGTs are taken from MARKAL assumptions in modelling work for the 2003 DTI Energy White Paper in Marsh et al. (2002).
[5] Coulomb and Neuhoff (2006).

two phases until 2012, power stations have or will be allocated most of the allowances for free, they have the opportunity to sell these allowances in the secondary market. Hence we include the full (opportunity) costs of CO_2 allowances as variable costs. The price of CO_2 allowances is assumed to be exogenous and set at €20/tCO2, which can be justified for example by the size of the UK power sector being small relative to the ETS scheme (see Keats and Neuhoff (2002) for further discussion).

Table 3 summarises the key differences between the 6 scenarios investigated in this chapter. Only maximum build rates for wind turbines and investment costs for wind turbines vary between scenarios. Investment costs can change for any of the following three reasons: First, with renewable support schemes some of the investment costs are covered by the subsidy, reducing the investment costs that have to be covered by revenues from the energy market. Second, grid connection costs for wind turbines can be higher, as they are potentially located further away from the grid and offer less economies of scale than large new power plants. Third, uncertainty about the future cost evolution of wind turbines, especially for off-shore applications, is high. To reflect these options we increase the investment costs of wind turbines by a constant. We exclude any additional income derived from the Renewables Obligation.

Scenario		**Contribution of wind to annual energy demand in 2020**	**Capital Cost of Wind required in 2005 (Euro/KW)**	**Details**
M1	Base Case	20%	1375	Wind achieves target of 20% of demand by 2020 using baseline assumptions with build limitations for Wind of 500MW per annum per region (ex. Scotland)
M2	Cheap Wind	40%	750	As with M**1** but for 40% penetration
M3	Cheap Wind: Transmission expansion	40%	750	As with M**2** but with 2GW transmission expansion to Scotland
M4	Base Case: No build constraint	20%	1550	As with M**1** but with no build constraint (and higher wind capital cost to fulfil 20% target)
M5	Cheap Wind: No build constraint	40%	1350	As with M**3** but with no build constraints
M6	Tailored build expansion	20%	1375	As with M**1** but with extended annual build constraint (+100MW) in one region in single time period

Table 3 - Overview of Scenarios

We also impose a regional build constraint on new investment in wind turbines of 0.5GW per year. This is based upon the German experience[6]. We do not impose the build constraint in Scotland where we consider land less scarce. This allows us to explore the impact of transmission constraints to Scotland and viability of adjusting the transmission capacity (a key challenge in the GB system).

4. Model Results

In this section we will show the model results for the different assumptions, and provide some interpretation of the implications.

4.1 Scenario M1 - Base case

The results of our Base Case run are shown below in terms of capacity additions across the period. This scenario is characterised by new investment in both wind and CCGTs. We do not observe any new investment in OCGTs in our scenarios. The high level of expansion in CCGT capacity is notable in the first 5-year period of our model run. This is driven by the relatively high CO_2 allowance price of 20€/tCO2 and gas prices that are based on long-term predictions of the IEA rather than current market prices which are much higher. This is a conservative assumption since higher gas prices would only increase the attractiveness of wind power.

[6] http://www.wind-energie.de/fileadmin/dokumente/statistiken/statisiken_englisch/jahreszahlen_2005_eng.pdf

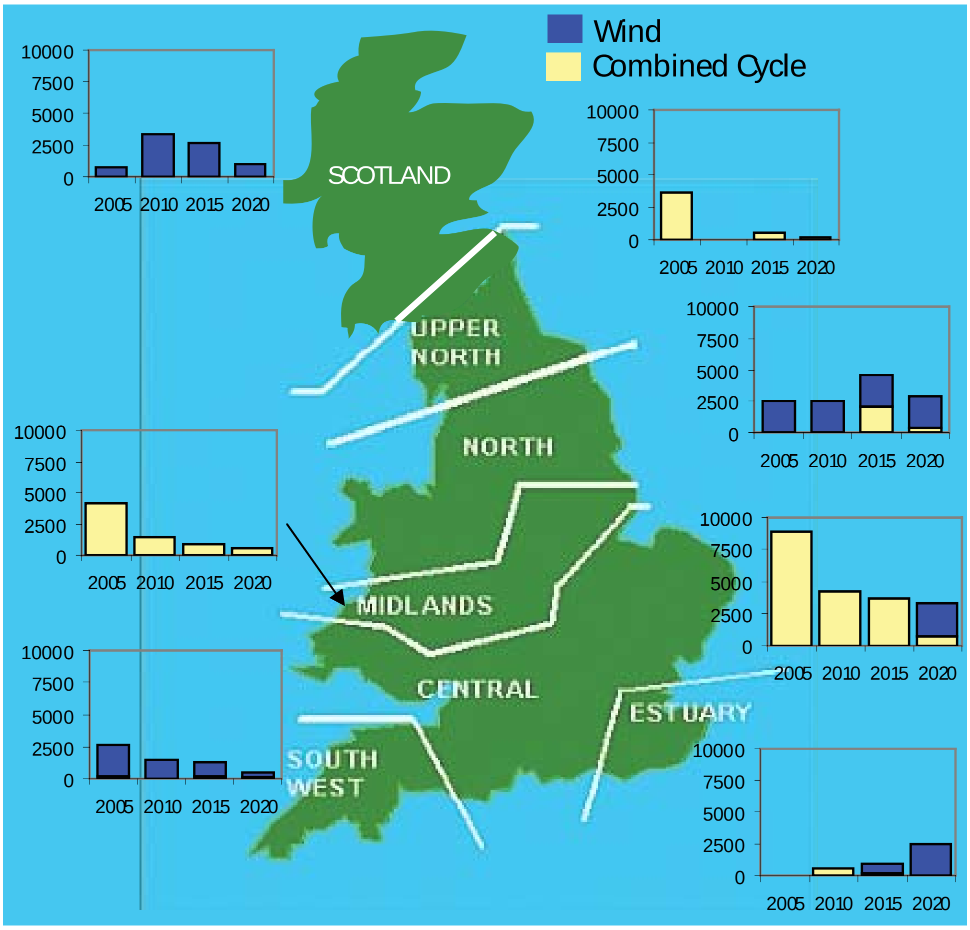

Figure 3 - Spatial distribution of new wind investment (MW), Base Case (Scenario M1)

Figure 4 illustrates the new investment picture characterised by CCGTs and wind turbines. Underlying this trend is an accompanying decline in Coal-powered generation and exogenously set closure of existing coal power stations. We calculated the timing and volume of closures in separate model runs where the different provisions of the Large Combustion Plant regarding SO_2 and NO_x emissions were explicitly modelled. In terms of new build, as we would expect given the quality of the wind resource, investment is focussed in the North, Scotland and the South-West of England. The imposed build constraint for wind power of 0.5GW per year is binding in the Northern region in all periods. In addition we see it restricting additional investment in the Southwest in 2005-2009 period and Central and Estuary regions in 2020-2024.

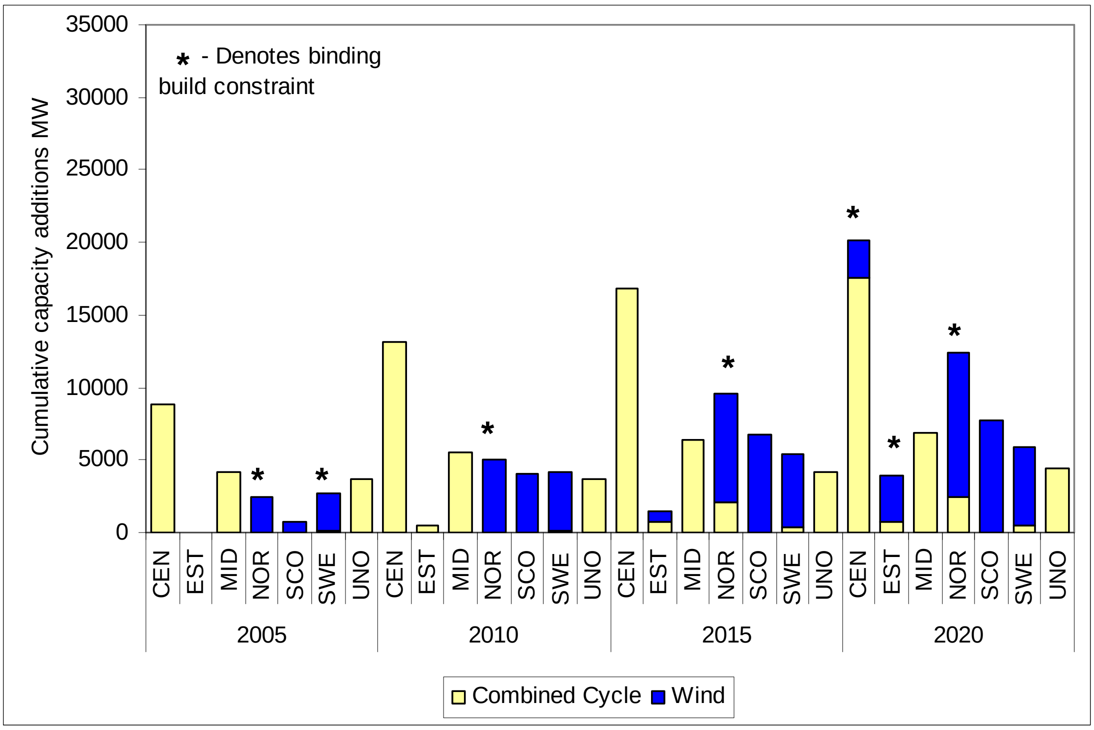

Figure 4- Cumulative capacity additions MW- Base Case (Scenario M1)

4.2 Scenario M2: Cheap Wind

In the second scenario we reduced the investment costs for wind power to achieve a penetration of 40% wind by 2020. We see a similar distribution of new gas-fired capacity early in the period to the Base Case. We also observe stronger wind investment, most notably in Scotland in the first period. Where our imposed build constraint is binding this has been shown by an asterisk above the bars in Figure 5. This shows that the constraint is binding in most regions in most time-periods.

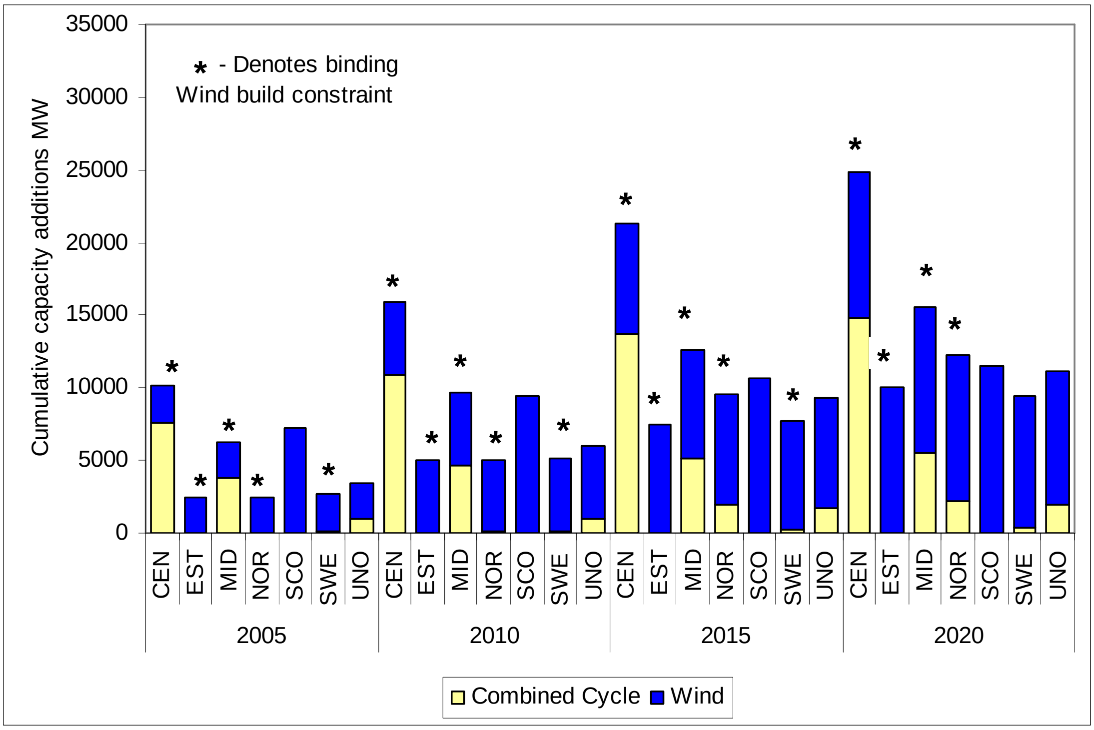

Figure 5 –Cumulative Capacity Additions (MW), Cheap Wind (Scenario M2)

Table 4 summarises the effect on total system costs. To achieve the higher wind penetration we reduced the assumed total cost for wind turbines including grid connection from 1375 Euro/KW to 750 Euro/KW in 2005. In the system cost comparison we corrected for this and added the subsidy costs (e.g. 625 Euro/KW in 2005) to total system cost. In this case a change from 20% to 40% wind power penetration results in discounted system costs rising by €9.9bn. This represents roughly 7.5% of total discounted system costs and total sales volumes. This result is very much contingent on our assumptions about wind turbine plus grid connection costs. If these costs are lower, then the level of required subsidy and thus increase in system costs are lower. But also the level of wind power penetration in the case without subsidy is higher.

A cost increase might be justified, e.g. as technology support, or because political constraints imply that the CO_2 price in the emission trading scheme is below the marginal damage caused by CO_2 emissions.

Indicative Years (in Mio. €/5years)	2005	2010	2015	2020	Total
Variable costs	-12	-36	-24	-23	
Fixed costs	0	0	0	0	
Fuel cost	-1243	-1468	-1938	-2321	
Capital repayments for simulated new build (with levelised costs of wind)	2067	3201	4310	4948	
CO_2 emissions valued at 20Euro/t	-287	-368	-468	-500	
Total	524	1329	1879	2104	5836
	2005-09	**2010-14**	**2015-19**	**2020-24**	**NPV**
Discounted Total System Costs	**2150**	**5452**	**7709**	**8630**	**9904**

Table 4 – Increase in Total System Cost from Scenario M1 to Scenario M2

4.3 Scenario M3: Cheap Wind with Transmission Expansion

In this scenario we expand the commercially available transmission capacity from Scotland via upper North, North, Midlands to Central by 2GW. We assume that this additional capacity is available from 2005. The simplification is intended to facilitate an intuitive understanding of the effect, rather than to reflect our best guess about the possible or desirable timing. The model simulates a sizable increase in new investment in wind power in Scotland of 3.6GW in the period 2005-2009.

The expansion in transmission capacity allows additional wind in Scotland to replace conventional gas generation elsewhere in the UK. As a consequence we see overall emissions fall in response to the transmission upgrade by 230m Tonnes CO_2 or 5% of total cumulative CO_2 emissions.

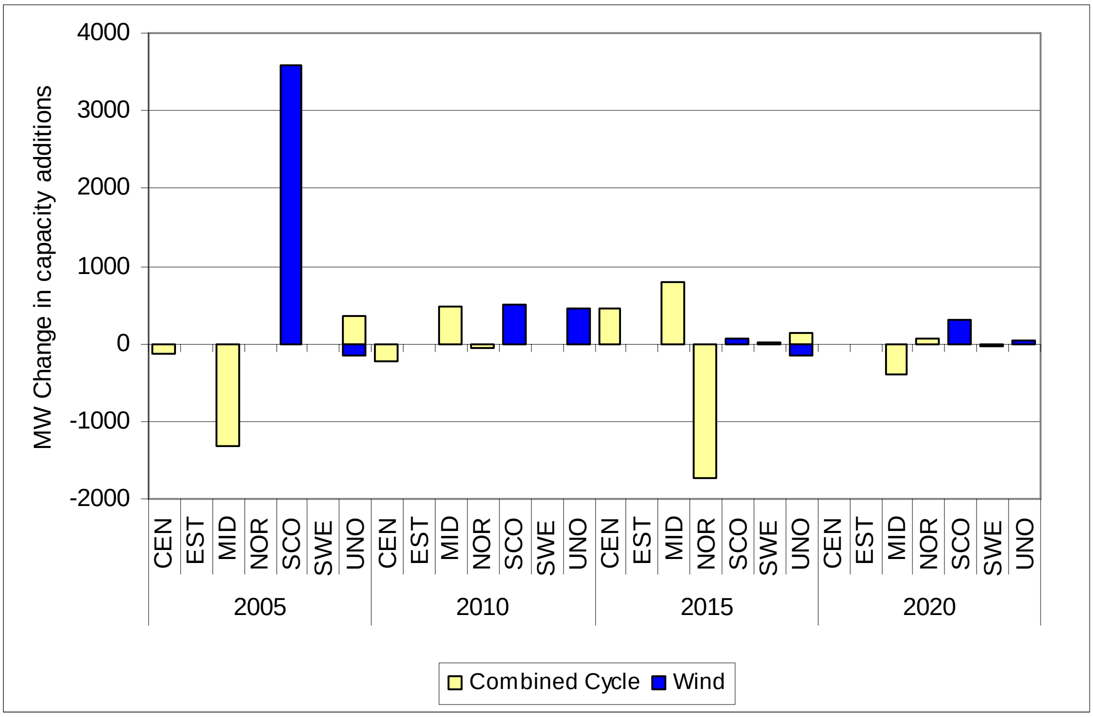

Figure 6 - Change in investment relative to Scenario M2 with 2GW transmission expansion

This illustrates the potential benefit of efficient congestion management. Current GB trading arrangements largely ignore transmission constraints. This limits the connection of new generation in the North of the UK because transmission constraints would be violated if additional stations would sell output at times when existing stations produce at large volumes. In an economic efficient solution some conventional power stations reduce output during times of high wind output. Also, if times of high wind output coincide with low demand in the North, then some wind output can be spilled. These two effects together allow for the connection of 3.6 GW extra wind generation capacity in Scotland even so the transmission capacity to the South only was increased by 2GW.

However, in the absence of nodal or zonal pricing it is difficult to allocate transmission capacity in a sufficiently flexible way. As a result the grid operator has incentives to be unnecessarily restrictive in connecting new generation capacity or requesting transmission upgrades.

Using the model we are able to calculate the overall impact on total system costs of the transmission expansion. An expansion in the transmission line creates the opportunity for additional building of wind turbines in Scotland to take advantage of the resource potential, yet allows avoidance of additional gas turbine investment and the associated CO_2 allowance and fuel costs. Table 5 shows a breakdown of the system costs associated with the transmission capacity. Here we see an annual saving of just under €0.8bn, with an overall NPV of €1.7bn - these savings do not include the cost of expanded transmission capacity, which are discussed below.

This saving is rather sensitive to model assumptions as it is the difference between fuel and CO2 cost savings and extra capital expenditure on more turbines. In the scenario analyzed here, low utilized wind turbines in the South are substituted with higher utilized wind turbines in Scotland. In a scenario with lower wind penetration (and significantly higher turbine costs), more transmission capacity allows for more use of wind instead of gas powered generation (Neuhoff et. al. 2005), resulting in average annual cost savings of 25million euros per GW transmission expansion (compared with 96million euros here).

Indicative Years (in Mio. €)	2005	2010	2015	2020	Total
Variable costs	-4	-9	1	-1	
Fixed costs	0	0	0	0	
Fuel cost	-329	-339	-349	-400	
Capital repayments for simulated new build	213	283	258	273	
CO_2 emissions valued at 20Euro/t	-84	-102	-89	-90	
Total	-204	-168	-179	-218	-769
	2005-09	**2010-14**	**2015-19**	**2020-24**	**NPV**
Discounted Total System Costs	**-837**	**-688**	**-736**	**-894**	**-1691**

Table 5 – Additional System Costs relative to Scenario M2 from increasing transmission capacity

The estimated capital costs of connection transmission expansion vary between studies. The PB Power (Harmer 2002) study puts the cost of a 2GW expansion of capacity based on "point-to-point" transmission for Offshore Wind would cost somewhere between €1700m (200km) and €2500m (700km). For a HVDC "grid" concept scheme, the cost estimate rises to between €2500m and €3400m. Neuhoff (2001) estimates the cost of a new interconnection to be between €190,000/km and €500,000/km with additional converter costs of around €57m/GW. In the case of a new 2GW onshore transmission line from Scotland to central England (approx. 600km) the cost-benefit case for expansion may alone be sufficient justification for such an expansion. However, this analysis did not take into consideration environmental impacts of transmission expansions and the trade offs between onshore and offshore transmission lines in the planning process.

€	**Harmer 2GW (offshore)**	**Harmer HVDC (offshore)**	**Neuhoff (onshore)**
200km	1170m	2500m	
700km	2500m	3400m	
Scottish link	<2500m	<3400m	220-800m

Table 6 - Cost estimates for 2GW Scottish transmission expansion. Sources: (Neuhoff 2001; Harmer 2002)

4.4 Scenarios M4 and M5: Base and Cheap Wind with no wind build limit

In the previous scenarios we applied a maximum build constraints of 0.5 GW per year for all regions except Scotland. In Scenarios M4 and M5 we remove the build constraints to see how investment patterns change. This shows how optimal policy needs to change if it takes public acceptability into consideration.

In order to see the impact of the removal of build constraints we increased the capital costs for wind by 13% relative to the 20% and by 80% relative to the 40% wind penetration cases such that we retained the same level of energy delivered from wind power.

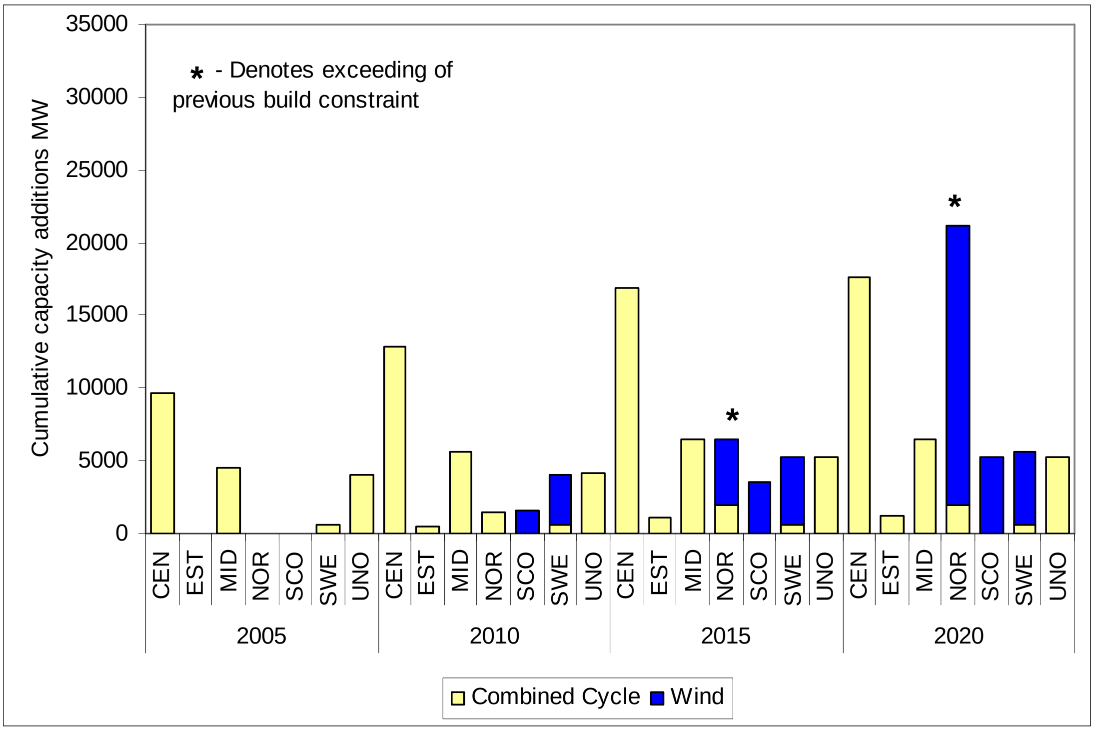

Figure 7 – Cumulative capacity additions (MW) by region- 20% wind with no build limit (Scenario M4)

Figure 7 and Figure 8 summarise our results. First, the wind investment is shifted towards the North region which enjoys one of the best resource potentials in the UK. In the Base Case with no limit, wind investment comes forward only in three regions as opposed to five of the total seven regions under the Base Case.

Second, the wind investment is delayed. In the Base Case with no limit most wind power is built in the final time period. In the Cheap Wind case with no limit the 20GW of wind in the first time period (Scenario M2) is shifted to the second period. As a result of the delayed investment in wind, the system faces a 20% increase in fuel costs of €565m/yr and additional CO_2 emissions of 330m tonnes by the end of 2024.

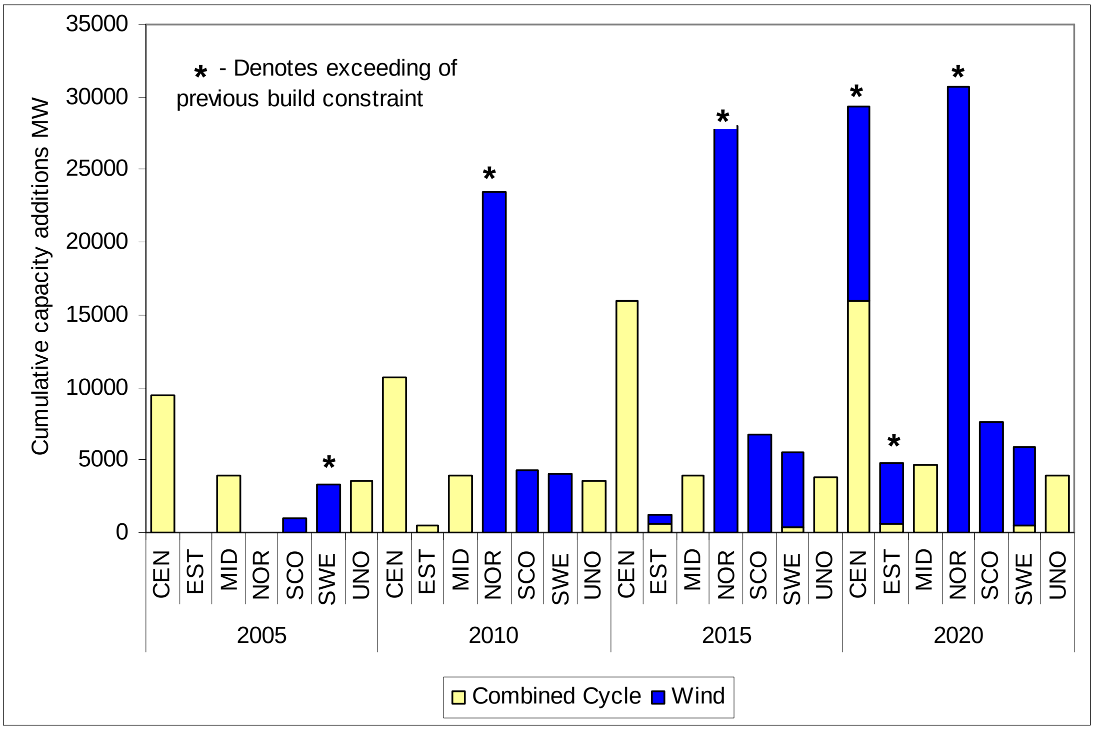

Figure 8 – Cumulative capacity additions by region (MW) 40% Wind with no build limit (Scenario M5)

These model runs illustrate the importance of considering, first, the maximum built rates, which are dictated by public acceptability, and, second, the implied maximum penetration rates, which are dictated by resource availability. If these constraints are taken into consideration in the modelling and therefore also in the policy design, then investment in wind power is spread more widely and deployment is started earlier to achieve the desired penetration.

Table 7 and Table 8 are included below to illustrate the system cost effects for scenarios M4 and M5, relative to their comparators; scenarios M1 and M2 respectively. As shown in Table 7 the overall saving from having no regional build limitations has a net present value of almost €1bn in 2005 of our model. This cost saving results largely from the decision to delay wind investment (scenario M4), where there exists no regional build limitation and knowledge of no future limits. The 20% wind target is achieved with significant amounts of wind being built in the final period, thus the deferred costs savings are notable (compared to the limited build case of scenario M1). This picture is repeated to a greater extent in Table 8 where cost savings here (scenario M5) are made up largely in deferred capital payments for the additional wind investment outlayed in the limited build scenario (M2).

Mio. €	2005-09	2010-14	2015-19	2020-24	Total
Variable costs	1	6	6	-7	
Fixed costs	0	0	0	0	
Fuel cost	565	670	651	-80	

Capital repayments for simulated new build	-734	-1023	-991	-103	
CO_2 emissions valued at 20Euro/t	141	181	170	-18	
Total	-28	-166	-164	-208	-565
Discounted Total System Costs	**-114**	**-682**	**-671**	**-852**	**-933**

Table 7 - System Costs for scenario M4 compared to scenario M1- Cost saving from relaxed planning constraint and 20% wind.

Mio. €	**2005-09**	**2010-14**	**2015-19**	**2020-24**	**Total**
Variable costs	17	15	19	19	
Fixed costs	0	0	0	0	
Fuel cost	1350	9	303	-410	
Capital repayments for simulated new build	-1068	-686	-1135	-921	
CO_2 emissions valued at 20Euro/t	323	-11	80	-99	
Total	622	-674	-734	-1411	-2196
Discounted Total System Costs	**2551**	**-2763**	**-3010**	**-5787**	**-1358**

Table 8 - System costs for scenario M5 compared with scenario M2- Cost saving from relaxed planning constraint and 40% wind.

4.4 Scenario M6: Tailored build expansion

An additional scenario was used to assess the marginal costs imposed on the system by maximum build constraints. These allow us to understand how much effort one might like to devote to increase public acceptability in order to relax such a constraint. We therefore increased the maximum build constraint for an individual region and modelling period from 500 MW per year to 600 MW per year to see how this changes the discounted total system costs of supplying the electricity demand of UK customers. Figure 9 illustrates the change in investment pattern relative to the Base Case that results if the build constraint in the North is relaxed from 500MW to 600MW per year for the period 2010-2014. This results in a shift of investment from gas-fired generation to wind.

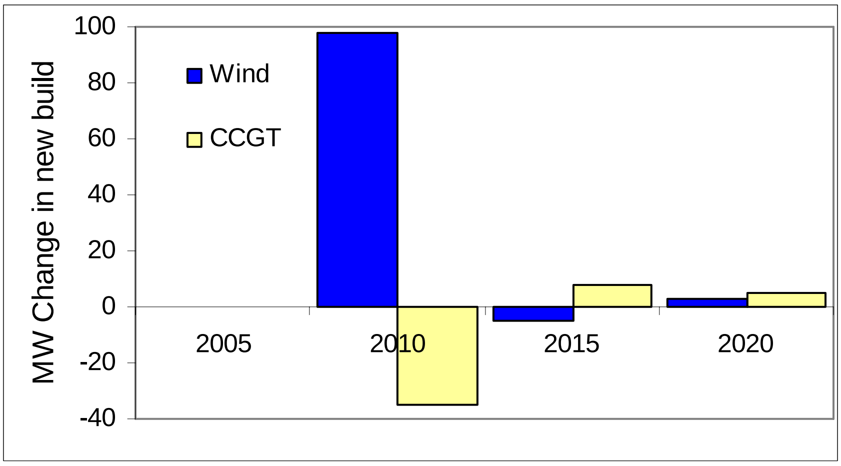

Figure 9 - Capacity Changes in North: Build expansion (Scenario M6) relative to the Base Case (Scenario M1)

Table 9 gives the reduction of the system costs if the maximum build constraint is relaxed in North. A similar exercise was carried out for the SWE and the results are shown alongside. As the constraint is not binding in SWE, the relaxation does not have any impact. In contrast, the opportunity to build an additional 100MW of wind in North during the period 2010-2019 creates system savings of about €250k/2.5MW turbine. This would be about 10% of construction and grid connection costs of such a turbine.

Impact of 100MW relaxed build constraint	**Cost Saving Mio Euro, 2005**	**Cost Saving Mio Euro, start year**
NOR 2010-2014	7.5 (2005)	12.7 (2010)
SWE 2010-2014	0	0
NOR 2015-2019	4.5 (2005)	12.9 (2015)
SWE 2015-2019	0	0

Table 9 - System Costs Savings from increasing the build constraint by 100MW

4.5 Comparison of Scenarios

In Table 10 we compare some of the scenarios. The additional costs in moving from a 20% to a 40% wind penetration scenario are 9.9 billion Euro discounted to 2005. If we divide this amount by the CO_2 savings calculated till 2025 then this extra costs amounts to 11 Euros/t CO_2 above the 20 Euros/t CO_2 already internalised in the model. If 2 GW of additional interconnector capacity from Scotland to the South were available (for free!), then these costs would fall to 7-8 Euros/t CO_2.

This number results if we assume that the net present cost of connecting and operating wind power at the system is 1350 Euro/KW, while for example the Markal model assumes the cost of building wind power is 800 Euro/KW. Our model suggests, that if the cost were 750 Euro/KW, then it would be cost optimal to operate the system with

40% energy delivered from wind in 2020.

Amount of Wind	Scenario	Models compared	NPV benefit to society at 20 Euro/tCO_2 (m 2005 Euros)	Cumulative change in emissions by 2025 ((Mt)	Change in emissions in 2025 (Mt/year)	Corresponds to CO_2 price increase (Euro/t)
20%	Saving from lifting build constraint	M4-M1	900	75.5	-0.5	12
20%	Marginal saving from increasing build limit by 100MW	M6-M1	4.5-7.5	-2.8	-0.1	-2 to -3
40%	Extra costs of 40% wind over 20%	M2-M1	-9900	-922.6	-25.8	11
40%	Saving from increasing Scottish interconnector capacity by 2GW* Relative to 20% scenario*	M3-M2 M3-M1	1200-1500 -8700 - -8400	-227 1149.6	-4.4 -30.2	-5 to -7 7 to 8
40%	Saving from lifting building constraint	M5-M2	1400	329.9	-1.4	4

Table 10 - Scenario Comparison Results (* excludes cost of interconnector)

The table also illustrates some implications from our modelling approach. We keep the target wind generation by 2020 fixed across different scenarios by adjusting the investment costs for wind power. Removing build constraints on the wind construction thus allows for a later build of wind power, which increases emissions in the period to 2020. Under circumstances where CO_2 were higher 12 Euro/t CO_2 in the 20% scenario or by 4 Euro/t CO_2 in the 40% scenario the building delay would not be economic. While we argued above that it is unlikely that we can remove all building constraints from the process of planning permission, grid connection and site availability, and thus need to accelerate early build to achieve significant target levels, this analysis also shows that earlier construction does not entail excessive cost. Note that all numbers are calculated relative to the high net present value costs of wind turbines of 1350 Euro/KW and fall in the scenarios with lower assumptions.

5. System costs

The previously described model runs could not capture all the dynamic constraints of the power sector and the regional detail within the transmission zones. We now refer to other studies that looked at the corresponding costs. To allow for a comparison of capital and operational costs we calculate the net present value of all costs involved, again using our standard discount factor of 11% and time horizon of 25years (Note, this implies that an annual cost of 1 Euro over 25years has a NPV of 9.35 Euro).

Euro/KW	Markal	IEA (2005)	Strbac	UKERC	Mues 24h	Mues 4h
Investment cost (2005)	800	1000				
Response			48			
Synch reserve			51	129	47	24
Standing reserve			16			
Start up			20		33	10
Distribution			28			

Table 11 Cost of wind that were not calculated endogenously (Marsh *et al* 2002; Strbac 2002; IEA 2005a; Muesgens and Neuhoff 2005; Gross et al. 2006)

Table 11 gives the summary of the different cost components that are not endogenously modelled. Estimates of investment costs can differ significantly. While published list prices for turbines are available for some countries, prices are typically negotiated bilaterally. Furthermore reported project and construction costs vary across countries, indicating that similar differences might apply within countries.

Studies of system costs of integrating intermittent wind power into the system have recently been comprehensively reviewed by the UK Energy Research Centre (Gross et al. 2006). The additional costs of dealing with the more volatile and less deterministic pattern of wind were estimated to be in the order of £3/MWh wind integrated in the UK system, which translates to 129Euro/kW wind installed and are in line with studies for other countries. Strbac (2002) provides more detail, splitting up the costs into additional cost components for the provision of different system services. We depict the number averaged over four scenarios with 20% and 30% wind penetration, but did all result in rather similar per kW costs. The aggregate figure is comfortably close to the best guess of UKERC. Muësgens and Neuhoff (2005) modelled the costs that wind power adds to the German system. In the current market design where the plant pattern is effectively fixed day ahead the costs of wind power are significantly higher than they could be if a more flexible operation of the system would allow for the use of forecasts updated 4 hours before actual dispatch.

The costs incurred for the expansion of the distribution network relate both to the direct grid connection and possible reinforcement of the regional distribution and transmission network. While most projects assessed by the IEA did include grid connection costs, they were not covered in the Markal model. Strbac calculated an average of 28€/kW additional distribution costs. This might be on the lower side, as local expansion of the transmission network might also be required, and in our model we only assess inter regional transmission capacity expansion.

6. Conclusions

The decarbonisation of the UK electricity system is likely to involve large shares of renewable electricity generation. We have developed a modelling approach that can capture the regional variation of wind output in the presence of transmission constraints and integrate this into an investment planning model. With surprisingly unchallenging cost assumptions, the system is able to deliver 20% or 40% of energy from wind output by 2020. We did however not model the regulatory, technology and price risk that investors perceive and that might increase the trigger prices for investments.

The approach did not explicitly represent technical constraints that affect operation like maximum ramp rates and minimum run constraints. Still, we referred to results from other models that are focused on the operation to represent related additional costs. We also ignored technical constraints, like fault ride through capabilities or minimum system inertia. Nevertheless, we hope that the quantitative framework that this modelling approach provides can support electrical engineers in their further analysis of these constraints and in finding solutions to address them. So far we could not estimate the costs and benefits that are related to, for example, improved power electronics.

One of the key constraints for the evolution of a system with large shares of renewables are maximum build rates in UK regions and transmission between them. We used a rough number of maximum build rates, to illustrate the value that can be provided to the system if such constraints can be relaxed and where this relaxation is most valuable.

While this work focused on the integration of intermittent generation using on-shore wind patterns, future studies will be required to understand the diversification benefit that off-shore wind farms can offer or that can be provided by other intermittent renewable energy sources like marine power and photovoltaic resources.

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