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Minimising costs and variability of electricity generation by means of optimal electricity interconnection utilisation

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Abstract: We examine the payoffs to electrical interconnection between isolated systems considering minimisation of both costs and variability. We demonstrate that optimal interconnection portfolios cannot be derived analytically and must be simulated numerically. We present a mixed-integer linear programme which maximises payoff to interconnection and simulates the operation of stylised electricity systems. Interconnection is considered as both an endogenous and an exogenous variable. Demand and wind portfolios of varying levels of correlation are considered. Endogenous interconnection is negligible under all demand and wind scenarios. Under exogenous interconnection, one region is found to gain at the expense of another regarding both cost minimisation and variance minimisation. Payoff from interconnection is found to be primarily due to supply side considerations, in particular the thermal generation portfolio.

Introduction

Modern power systems have undergone liberalisation in many countries. Electricity generation and supply have changed from being the responsibility of a state-owned regulated monopoly to a competitive market structure, while transmission and distribution largely remain as regulated monopolies (Al-Sunaidy and Green 2006). Furthermore concerns surrounding climate change and security of supply have led to a large growth in renewable generation, often in response to government targets (European Commission 2009, Wiser 2012). Integrating variable renewable generation, such as wind and photovoltaic generation, introduces an extra level of variability to the generation supply which must be countered by varying the output of conventional generation. Assuming risk-averse consumers and producers, such variation leads to a loss in utility.

Variation in electricity demand requires units to increase or decrease their generation throughout the day. These variations in supply lead to varying short-run marginal costs of provision, which in turn induce variability in the market price of electricity. Assuming risk-averse agents, this variation is not desirable from either consumers' or producers' points of view. Indeed, regulators often attempt to shield risk-averse consumers from time-varying prices to the extent that real-time pricing is not available in most markets (Allcott 2011). Variable renewable generation, which enjoys priority dispatch in many systems (European Commission 2009), can exacerbate this problem, particularly if generation is not correlated with demand.

One proposed means of mitigating these, and other, effects is increased interconnection between electricity systems and/or markets. An interconnector is defined for the purposes of this paper as a transmission asset which connects two separate systems, markets or balancing areas[1]. Interconnection investment exists both as merchant interconnection and as regulated assets owned by a Transmission System Operator (TSO) or other regulated state-owned entity. Interconnectors allow the import or export of generation to and from neighbouring regions. Thus if regions have anti-correlated demand or renewable generation portfolios, interconnection can lead to a smoother total demand and supply portfolio. This can reduce generation costs by allowing a more efficient use of conventional units, for example by increasing the capacity factors of baseload generation units, which generally have low incremental costs but are restricted as to their ability to adjust their output, particularly over short time horizons. In addition, interconnection can also reduce variation in supply, and consequently in electricity prices.

The potential benefits in terms of cost reductions and welfare increases from interconnection are examined by (Turvey 2006, Spiecker, Vogel et al. 2013). Regulatory questions regarding ownership and operation of interconnection have been well-covered in the literature (Gilbert, Neuhoff et al. 2004, Brunekreeft 2005, Brunekreeft, Neuhoff et al. 2005, Neuhoff and Newbery 2005, Brunekreeft and Newbery 2006). There is also an extensive literature on the technical and economic implications of specific interconnection projects (Kanagawa and Nakata 2006, Valeri 2009). Modelling techniques employed to determine the effects of interconnection include linear and mixed integer programming as well as various heuristic methods; for a full examination see (Lee, Ng et al. 2006). The general welfare effects of interconnection considering variable wind power is examined in (Spiecker, Vogel et al. 2013) and the interaction between interconnection and renewable targets is examined in (Lynch, Tol et al. 2012). (Roques, Hiroux et al. 2010) use a portfolio approach in considering the optimal location of wind power developments throughout Europe considering not only the level of

[1] In the United States, an 'interconnector' can also refer to the connection of a large generator to the grid.

wind output but also its variance. However, the variance of utility from electricity generation and consumption, and the ability of interconnection to influence same, has to the best of our knowledge not been examined in the literature to date.

This paper examines the potential for interconnection to increase welfare not only by reducing generation costs but also by reducing the variance of utility from electricity generation and consumption through diversification of supply and demand. Optimal interconnection is examined by means of a numerical approach whereby the effects of varying demand and wind portfolios on both utility and its variance are determined for two stylised test systems. The effect of variance between systems is also compared to a no-variance scenario in which two identical systems are connected. It is found that varying demand and wind scenarios do not have a large effect, while variations on the conventional supply side bring about changes in dispatch and costs. The magnitude of these effects is system-specific.

Interconnection, price determinants and price variance

Electricity is a unique good in that it cannot be cheaply stored. Demand for electricity must therefore be met instantaneously at each point in time by varying the output of generators. Demand for electricity varies strongly, realtime pricing is rare, and demand is inelastic. Furthermore, most sources of renewable electricity, such as wind and solar, are variable. Conventional generators experience unscheduled outages. This leads to a variable supply curve. Net yield, subtracting renewable generation from demand, must be served by electricity generation from conventional generation units. Ignoring unscheduled variability in supply from conventional sources, this yields a fixed supply curve, or merit order curve, and a time-varying demand curve.

Risk-averse producers would take this variability into account when deciding on investment. Interconnection would affect not only the expected return on investment, but also variability.

An interconnector allows electricity generation in one region to serve the demand in the neighbouring region. This can also be thought of as allowing a region to shift part of its demand to its neighbour. Baseload generators, which by definition have the lowest operating costs, tend to also have high start-up costs and times, and tend be limited in their ability to change output levels, particularly over short periods of time. Examples are nuclear, coal and combined cycle gas turbine (CCGT) plants. In contrast, more flexible units with low start costs and times, and which can vary their output rapidly, tend to have much higher operational costs. Open cycle gas turbines (OCGTs) are an example. Interconnection can allow a region to shift peak demand to a neighbouring region, reducing the hours that demand is met by high cost generation, which reduces costs and prices. Interconnection can also allow a region to export generation at times of low net demand, allowing baseload units to increase their capacity factors or avoid a shut down (and the subsequently costly start). In other words, interconnection can decrease generation costs by smoothing the net demand curve of the interconnected regions, allowing cheaper baseload units to *increase* their capacity factors (while more expensive peaking units *reduce* their capacity factors).

Economic benefits are further increased if the variance of prices can be reduced. Any smoothing of the demand curve brought about by interconnection will mean there is less switching between units used to meet demand. This in turn leads to less variation in the marginal cost of generation, which sets the electricity price. A reduction in the variance of prices is advantageous to producers, consumers or both, depending on the competition in the market. Price variance falls in both interconnected regions, whereas the expected price goes up in one region and down the other.

In order to determine the optimal level and utilisation of interconnection, it is therefore necessary to consider both mean and variance. The electricity price in an isolated system is a function of the fuel prices and the share of total generation taken up by each generation technology, as well as demand and renewable generation. Other factors include the day of the week, the season and public holidays. Similarly, the volatility of electricity prices is a function of the volatility of all those input factors. Electricity spot price and its volatility as functions of these inputs can be estimated *ex post* by analysing historical data (see for example (Karakatsani and Bunn 2010, Swinand and Godel 2012, O'Mahoney and Denny 2013)). For interconnected systems, the price is also a function of the price on neighbouring systems and the size of the interconnector. The price on the neighbouring system is in its turn a function of the fuel prices and shares and the demand and renewable generation of that system. It follows that the variance of electricity price is also a function of these factors. Unfortunately, given the mathematical complexities of the unit commitment and economic dispatch of generation units and the impact of interconnection, we have been unable to find a model that is both analytically tractable and insightful. We therefore resort to numerical simulation to explore these effects further for a small set of representative test systems.

Model description

A mixed-integer program is used to determine the optimal portfolio of interconnection for a given set of regions. Thus the interconnection portfolio which maximises the payoff from interconnection is determined. This payoff is given by the total electricity demand minus the cost of electricity generation across all regions:

$$max \sum_{r=1}^{R} Demand_r - \ Cost_r \qquad (1)$$

As demand is taken to be price-inelastic the problem reduces to minimising the cost of electricity, which yields the socially optimal market schedules that will prevail under competitive market conditions. Thus the market-clearing schedules are determined and producer surplus is also maximised considering the problem as a cost-minimisation problem such as in (Spiecker, Vogel et al. 2013) and (Hirth 2013).

Electricity cost includes the cost of generating plus the cost of interconnection. Each region has a generation portfolio comprising conventional fuels, hydroelectric units and wind generation. Generation costs are determined using a standard unit commitment and economic dispatch model similar to that found in (Shortt, Kiviluoma et al. 2013) or (Lynch, Shortt et al. 2013). Generation costs in each region have three components; start costs, no load costs and variable costs. Thus costs are calculated according to equations 2, 3 and 4:

$$start\_costs = \sum_{starts_r} start(units(r),t) * start\_cost(units)\ \forall\ r,t \tag{2}$$

$$no\_load\_costs = \sum_{units_r} online(units(r),t) * no\_load\_costs(units) \forall r,t \tag{3}$$

$$variable\_costs = \sum_{units_r} generation(units(r),t) * variable\_cost(units)\ \forall\ r,t \tag{4}$$

where $start$ is a binary variable indicating whether an inflexible unit was started in that time period and $online$ is a binary variable indicating the on-off state of each inflexible unit in each time period.

A capacity constraint ensures that no conventional unit generates above its capacity, and also ensures that units only generate when their on-off state is set to on:

$$generation(units(r),t) \leq online(units(r),t) * \ capacity\big(units(r)\big) \forall\ r,t \tag{5}$$

A start cost is incurred only in the time periods where a unit started, as calculated by equation 6:

$$start(units(r),t) \geq online(units(r),t) - \ online\big(units(r),(t-1)\big) \forall\ r,t \tag{6}$$

As $start$ is a binary variable, and as the model will seek to minimise costs, including start costs, $start$ will be set to one when $online$ was zero in the previous time step and one in the current time step; in all other cases $start$ will be set to zero.

In order to examine the impact of interconnection a variable $demand\_shift$ is introduced which allows a region to shift its demand to a neighbour. Demand is shifted from a $source$ to a $sink$. Every region r can act as both a source and a sink. A new variable new_demand

thus represents the total demand that must be met in each region and includes the demand in that region along with any exports that are required:

$$new\_demand(r,t) = demand(r,t) + \sum_{source} demand\_shift(source,r,t) \qquad (7)$$

A demand balance constraint ensures that there is sufficient generation in each region to meet the demand in each region and to meet any demand shifted to that region. In practise, this means there must be sufficient generation to meet demand within the region and to export to other regions at each time step:

$$\sum_{source} new\_demand(r,t) = \sum_{units_r} generation(units(r),t) \forall\, r,t \qquad (8)$$

Constraint (9) limits electricity import and export to the capacity of the interconnectors:

$$demand\_shift(source, sink, t) \leq ic\_capacity(source, sink) \forall\, t \qquad (9)$$

Constraint (10) imposes a limit of 50% on non-synchronous generation, i.e. generation from DC interconnection and from wind generation (as explained below, all interconnection is considered DC). This is to reflect some of the inherent difficulties in integrating variable generation while maintaining system stability:

$$\sum_{source} demand\_shift(source,r,t) + wind(r,t) \leq demand(r,t) * 0.5 \;\forall\, r,t \qquad (10)$$

In order to examine risk aversion ideally one would include the variance of utility in the objective function, i.e. by raising the objective function to a power of γ where $\gamma \in (0,1)$. However this would require the use of mixed-integer non-linear programming and so for the purposes of this study risk aversion was omitted in order to maintain a linear problem. The effects of variance are instead explored implicitly rather than explicitly by examining the interconnection portfolios and results that arise when varying input sets are used.

Data and cases

The effects of demand and wind profiles with varying levels of correlation are examined by determining the optimal dispatch through numerical simulation for two stylised electricity systems. The generation capacity portfolio on each system is fixed and the simulations are performed for different demand and wind scenarios. Four different wind and demand scenarios for each stylised system are considered. Interconnection investment between the systems is first considered as an endogenous variable and then the effects of interconnection are probed further by introducing varying levels of interconnection exogenously and examining the effects on the unit commitment and economic dispatch of the generation capacity.

Demand and wind data

The four wind and demand scenarios are based on real data obtained from various European system operators. Real data is chosen to maintain some element of realism while examining the effects of interconnecting regions with varying demand profiles. To this end demand data is taken from the British, French and Finnish systems and is applied to the stylised systems. These countries are chosen as there is some level of correlation between the demand in France and Great Britain, with divergence between the systems driven by higher summer demand and lower winter demand in France relative to Britain. In contrast, Finland has strong industrial loads and so has less variability in its demand on a daily basis than the other two systems. Figure 1 shows the demand at each hour of the day averaged over a year for Great Britain, France and Finland. For ease of comparison the peak demand of each system has been scaled to 10GW.

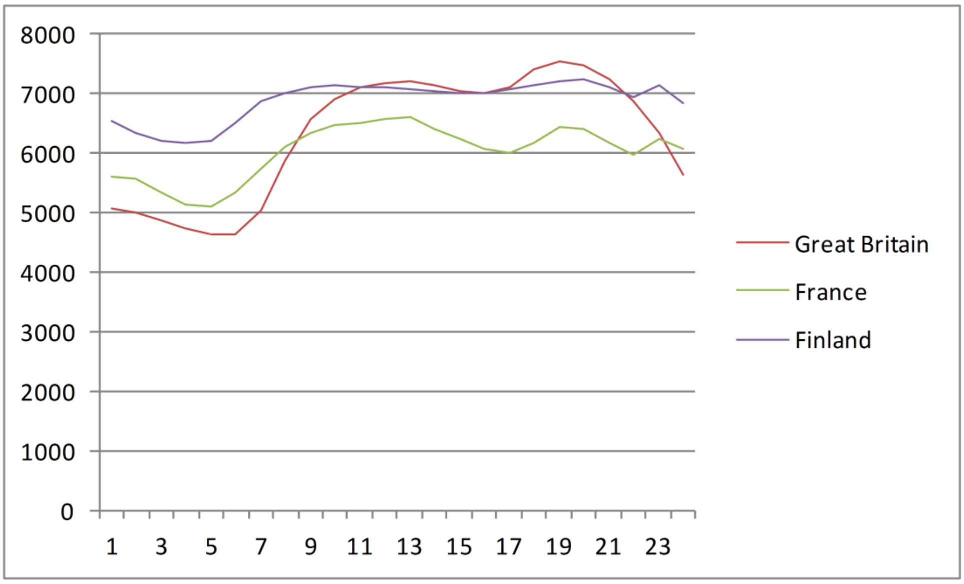

Figure 1: Hourly averages of scaled electricity demand

Four demand scenarios, which we designate as demand scenarios I, II, III and IV are constructed for the two stylised systems, which we refer to as systems *A* and *B*. Table 1, the demand scenario table, outlines how each demand scenario is constructed from the real demand data. In demand scenario I the real data from the systems is used and in scenarios II-IV the scaled data, with peak demand of 10GW, is used.

	I	II	III	IV
A	Britain	Britain (scaled)	Britain (scaled)	Finland (scaled)
B	France	France (scaled)	Finland (scaled)	France (scaled)

Table 1: Demand used in demand scenarios I, II, III and IV for the stylised regions *A* and *B*

The wind scenarios chosen are also derived from real wind generation data. The wind data chosen come from six European system operators, namely those of Ireland, Great Britain, France, Germany, Belgium and East Denmark. The averaged hourly wind output from each of these six systems, expressed as a capacity factor, is seen in Figure 2.

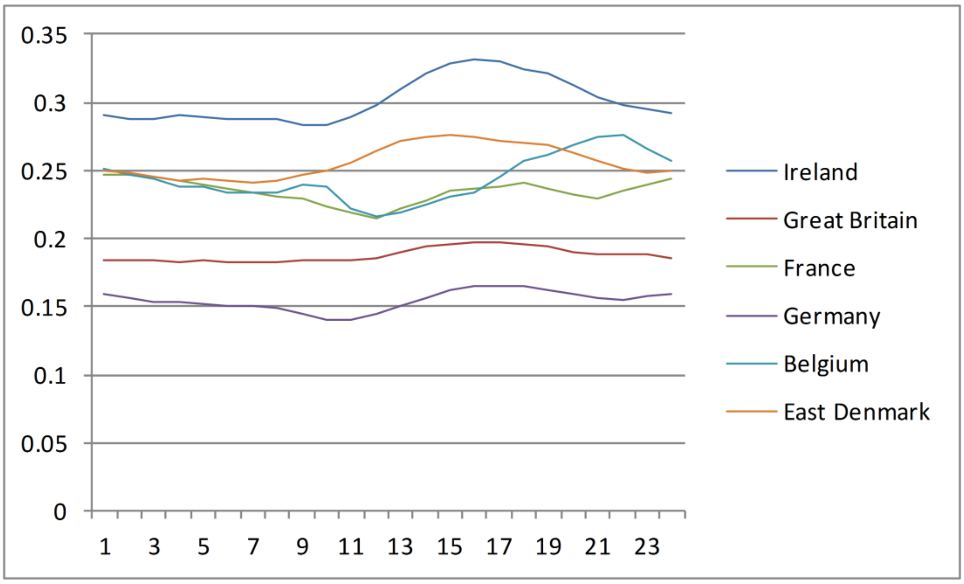

Figure 2: Total averages of wind capacity factor

Wind scenarios, which we refer to as wind scenarios i, ii, iii and iv are constructed for each of the two systems. The scenarios are summarised in Table 2, the wind scenario table.

	i	ii	iii	iv
A	Britain	Ireland	France	Belgium
B	France	Ireland	Germany	East Denmark

Table 2: Wind used in wind scenarios i, ii, iii and iv for the stylised regions *A* and *B* .

Generation and capacity data

The generation mixes for the two systems *A* and *B* considered in the study are also based on real systems. The generation portfolios of each of the regions are separated by type into Coal, CCGT, Nuclear, OCGT, hydro and wind generation. OCGT start costs and no load costs are very low compared to their variable costs and so these costs are ignored and OCGT capacity in each region is considered as one unit. In demand scenario I, the size of all other conventional units is 5000MW, with the exception of nuclear generation on system *B* which are 5500MW in order to allow easier averaging of units. In demand scenarios II-IV the size of coal and CCGT units on each system is 500MW while nuclear units are 1000MW. Table 3 gives the installed capacities of each generation type in demand scenario I, which is a simplification of the actual generation capacity on the British and French systems as of 2009 (Viswanathan and Gray 2001, Eurostat 2011). The installed capacities for demand scenarios II-IV are as in Table 3 but scaled according to peak demand of 10GW in each system.

	A	*B*
Coal	30	25
Nuclear	10	65
CCGT	30	25
OCGT	7	0
Wind	8.4	7.5
Hydro	1.65	2.58

Table 3: Installed generation capacity in each region based on British and French systems (GW)

Existing interconnection between regions is taken to be zero; the regions are treated as island systems in the first instance. The generation costs characteristics are the same as those used in (Lynch, Shortt et al. 2013, Shortt, Kiviluoma et al. 2013) and the resulting operational costs used are given in Table 4.

	Start Cost	No load cost	Incremental cost
Units	€	€	€/MWh
Coal	50,000	485	65
Nuclear	300,000	2,900	11
CCGT	100,000	1,940	40
OCGT			83

Table 4: Generation technology cost characteristics

Historical hydroelectric generation is sourced from the British and French system operators. Water flows are not explicitly modelled and so historical hydro generation is taken as the maximum hydro output for each hour in the simulation. For consistency the hydroelectricity generation is scaled according to a peak demand of 10GW on each system for demand scenarios II-IV.

DC interconnection is chosen for two reasons. First, the systems considered are island systems, and so we assume that interconnection is over a long distance and/or overseas, and so would require a DC interconnector. Second, AC interconnection cannot be directly controlled whereas DC interconnection can (Turvey 2006). The model assumes that the flow over the interconnectors is a control variable rather than a consequence of imbalances between the systems and so is best modelled as a DC flow. The cost per MW-km of DC interconnection is taken from (Bahrman 2006).

The simulations are run at hourly resolution for a full year using demand and wind data from 2013. Thus the unit commitment and economic dispatch of the units, along with interconnection investment, is optimised over a 8760 hour time period. The simulations are performed using the Generic Algebraic Modelling System (www.gams.com) and the mixed-integer feature of the CPLEX solver. The duality gap is set at 0.5%. The simulations took between 1 and 3 hours to complete depending on the wind and demand scenario selected, using an Intel core i7 3-GHz processor with 16GB of RAM.

Results and discussion

Interconnection investment

The model is run with interconnection investment included as an endogenous variable for every wind and demand scenario, or for sixteen scenarios in total. Interconnection investment takes place in one of the sixteen simulations. The scenarios in question are demand scenario III and wind scenario iii, in which 18MW of interconnection investment takes place. This interconnection is operated at full output for every hour of the year, although the direction varies; for 118 hours of the year region *B* exports to region A and imports from region A the remainder of the time.

This low level of endogenous interconnection is in keeping with the findings in (Lynch, Tol et al. 2012). The model in Lynch, Tol et al. did not consider the integer nature of generation units and so ignored start costs and no load costs, and found that significant wind generation capacity is required to bring about high levels of interconnection investment. Thus the specific modelling of individual units undertaken in this study, including start and no-load costs, did not induce sufficient savings to justify interconnection investment in order to avoid starting new units. A change in generation mix, either of renewable or conventional generation, could bring about higher levels of interconnection investment to those considered in this study but changes in demand and wind portfolios examined here had little effect.

Payoff from exogenous interconnection

In order to examine the interplay of interconnection-payoff maximisation and variance reduction, interconnection is removed as an endogenous variable and the simulations are performed for various levels of interconnection which are set externally. In this sense the analysis is similar to that of (Spiecker, Vogel et al. 2013). Interconnection between the regions is considered in 500MW increments from 0 to 5000MW. The cost of interconnection investment is not included. The percentage change in total generation costs, which is the payoff from interconnection for each level of interconnection, relative to the case with no interconnection, is given in Figure 3.

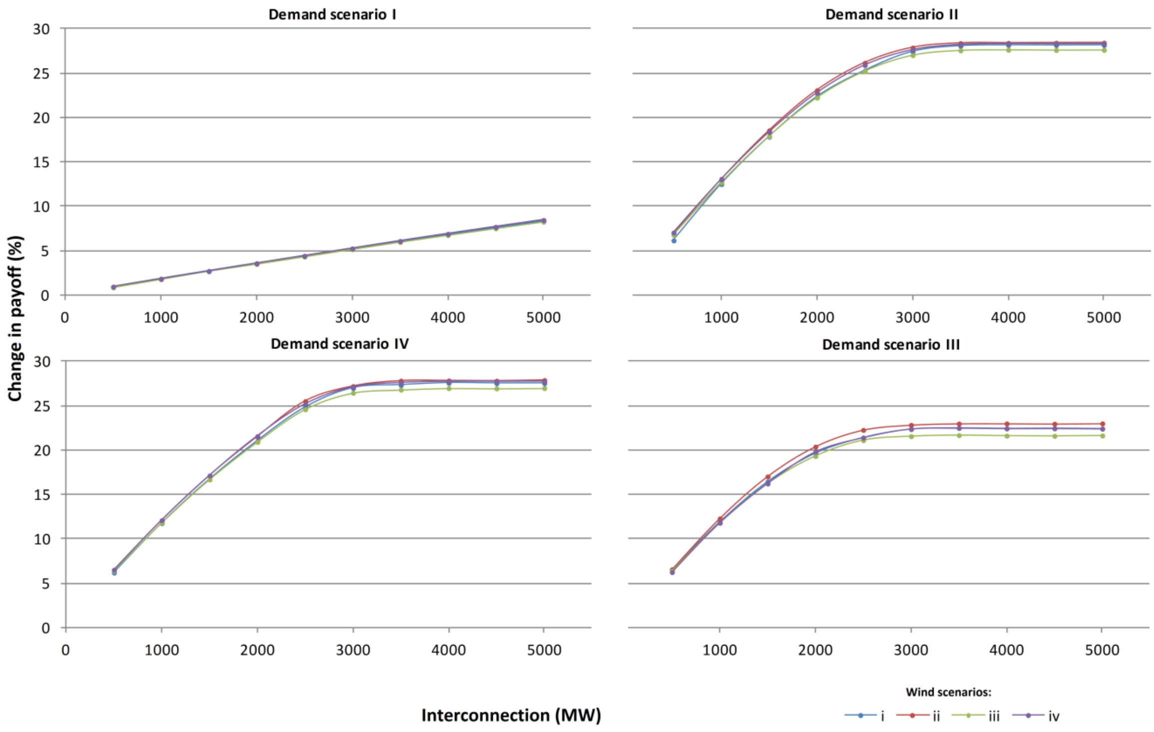

Figure 3: Change in payoff for each demand and wind scenario as a function of interconnection

The payoff increases for each level of interconnection. This is to be expected as the optimal dispatch for a given level of interconnection can be repeated for any higher level of interconnection and so acts as a lower bound on the payoff for any higher level of interconnection. It is clear that there is little effect from the various wind scenarios as the change in payoff is similar for each wind scenario. Demand scenario I, which uses real data from the British and French systems, sees a linear increase in payoff as interconnection increases. The increase in payoff is small compared to the other demand scenarios as even at 5000MW the size of the interconnector is small in comparison to system demand (for either system). For each of the scaled scenarios, however, the increase in payoff is non-linear and appears to saturate at an interconnection level of 30% of peak demand, or 3000MW of interconnection. After this point any efficiencies to be gained from a different dispatch are exhausted. The average demand of each of the scaled systems under consideration in demand scenarios II-IV is between 6000MW and 6900MW, which means that interconnection of

3000MW is roughly 50% of average demand. We assume that had we continued to increase the size of the interconnection in demand scenario I to 50% of the unscaled peak demand, that the same effects would be seen whereby the efficiencies to be gained from interconnection saturate at 30% of peak demand, as in demand scenario II.

The change in generation costs for systems *A* and *B* are given in Figure 4.

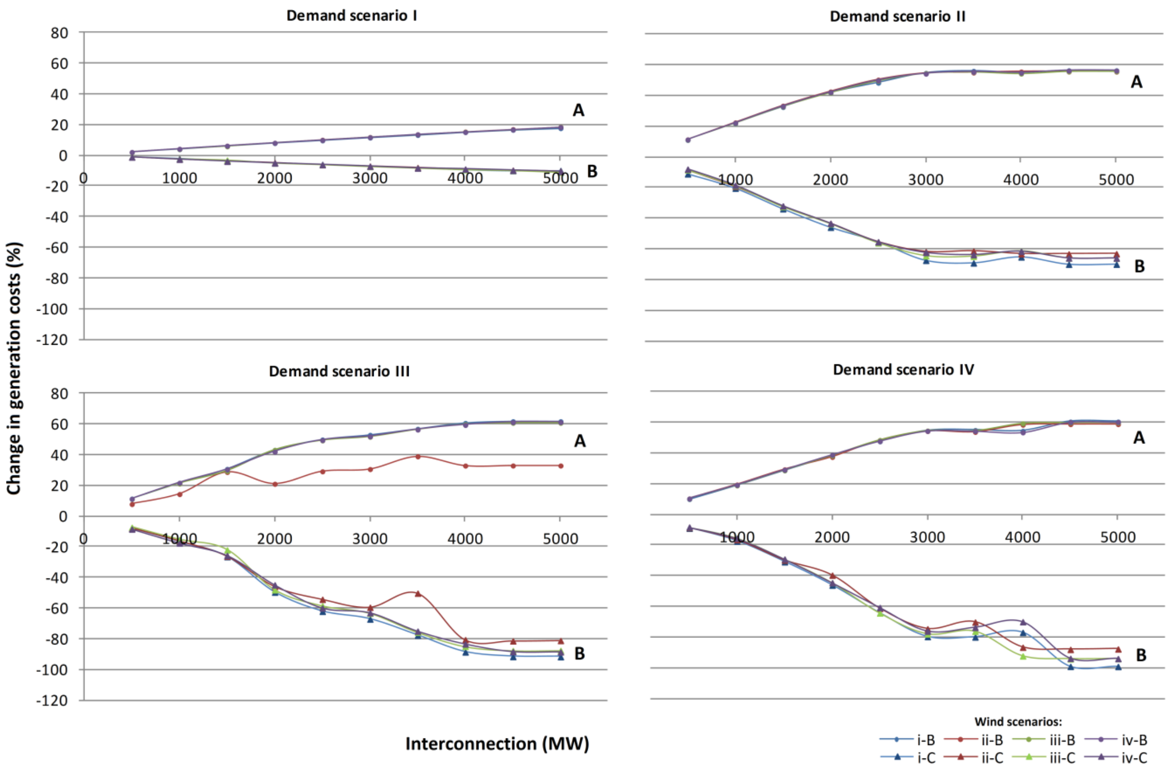

Figure 4: Change in costs for each demand and wind scenario and regions as a function of interconnection

In every case there is a positive change in costs in region *A* and a negative change in costs in region *B.* Thus costs in region *A* decrease while costs in region *B* increase. The effect of wind scenarios on the costs in each region is still small but is somewhat more noticeable than the effect of wind on total payoff. The effect of the various demand scenarios is small. It is thus likely that the primary value of the interconnector is on the supply side, for example in allowing an increase in nuclear generation from region *B* and a reduction in more expensive generation, whether of baseload or peaking units. Considering the marginal cost of electricity provision to be the hourly electricity price, we calculate the change in energy payments made by consumers in each region as interconnection increases in Figure 5.

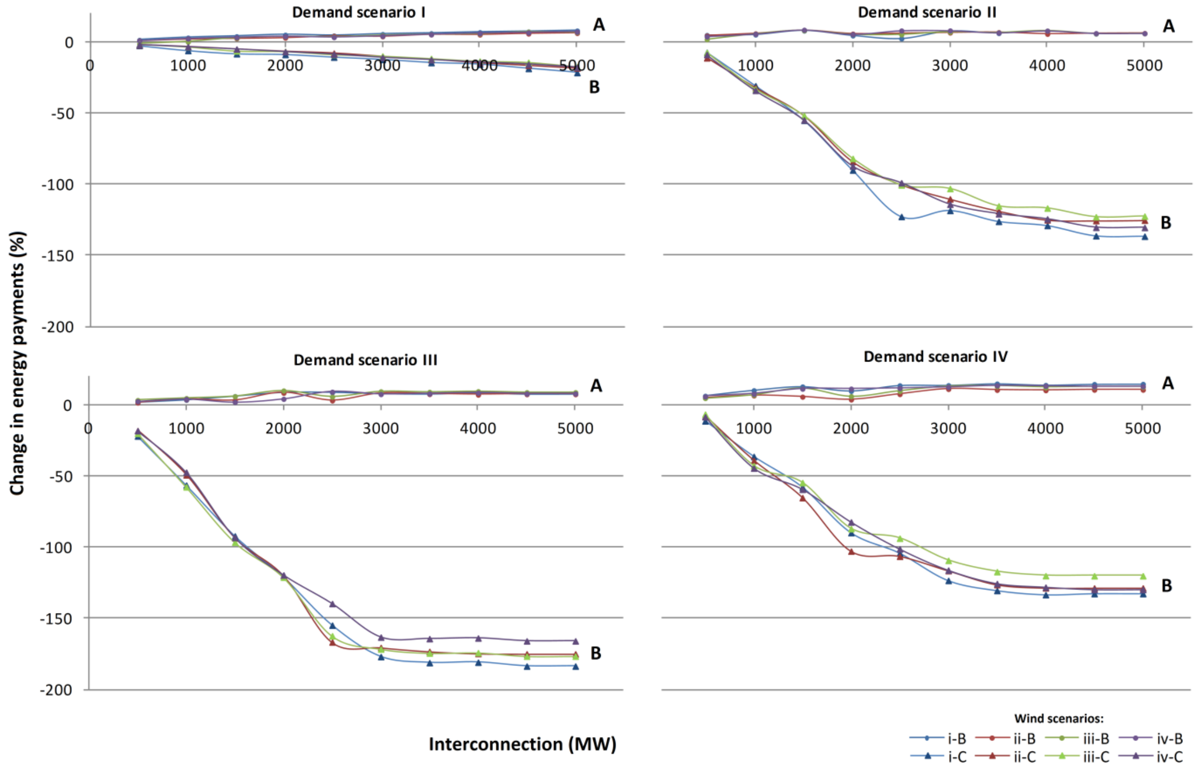

Figure 5: Change in energy payments made by consumers for each demand and wind scenario and region as a function of interconnection

It can be seen that energy payments by consumers in region *A* decrease by up to 13%. Energy payments in region *B* however see a much larger increase of up to 130% for demand scenarios II and IV and 165% for demand scenario III. Thus the consumers of region *A* are seen to gain at the expense of consumers in region *B.* This effect is also seen to saturate at 3000MW of interconnection for the scenarios with scaled demand. The extra increase in energy payments in region *B* under demand scenario III is of note. Demand scenario III actually saw a lower increase in total payoff than scenarios II or IV (Figure 3) and so while the decrease in total costs under scenario III may be less than the other scenarios, the plant utilisation and thus electricity price must show a greater divergence from the no-interconnection case. The lower level of intra-day variability for demand in Finland relative to that of Britain (the two systems used in demand scenario III) may account for this.

Variance effects of exogenous interconnection

In order to consider the effects of diversification, we consider the standard deviation of payoff on each system as a measure of the variability of payoff. The change in standard deviation of payoff is shown in Figure 6.

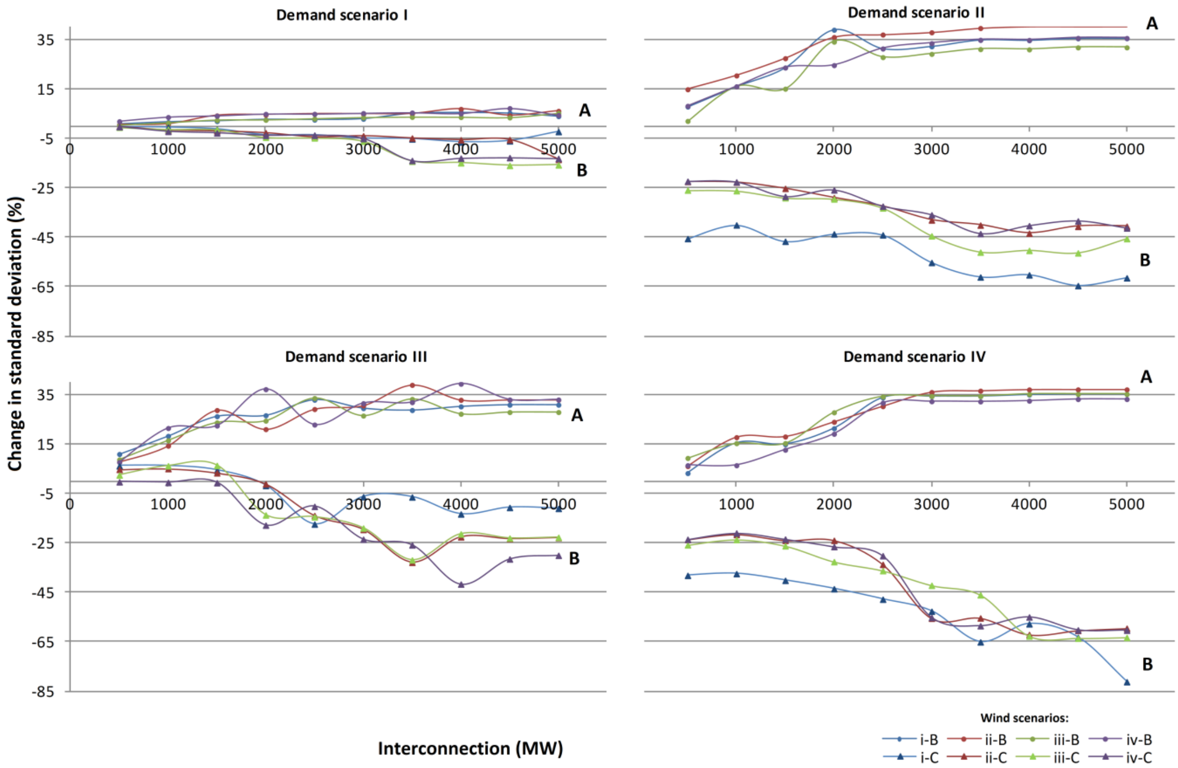

Figure 6: Change in standard deviation of payoff for each demand and wind scenario and region as a function of interconnection

The standard deviation of payoff in region *A* decreases as interconnection increases while the standard deviation in region *B* increases. Thus region *A* enjoys an increase in payoff and a decrease in the variability of payoff at region *B*'s expense. Furthermore, for region *B* at least, this effect does not appear to saturate at 3000MW as the other effects for demand scenarios II-IV did. The variability of payoff continues to increase as interconnection increases, although there does not appear to be a corresponding decrease in variability on system *A*. The different wind scenarios also appear to have more of an effect here, although there is no discernible pattern. For demand scenario II, for example, wind scenarios ii and iv have a similar effect, although the correlation between the wind portfolios on each system is very different. In demand scenario III, wind scenario iv sees the greatest increase in payoff variability on system *B* and the greatest decrease in variability on system *A*.

As payoff is given by quantity of electricity demanded minus the cost of generation, and as the demand in each region is fixed, the change in variability of payoff to interconnection arises from a change in variability of generation costs. Figure 7 shows the standard deviation of the marginal cost of electricity provision for each region, which is the market price for electricity.

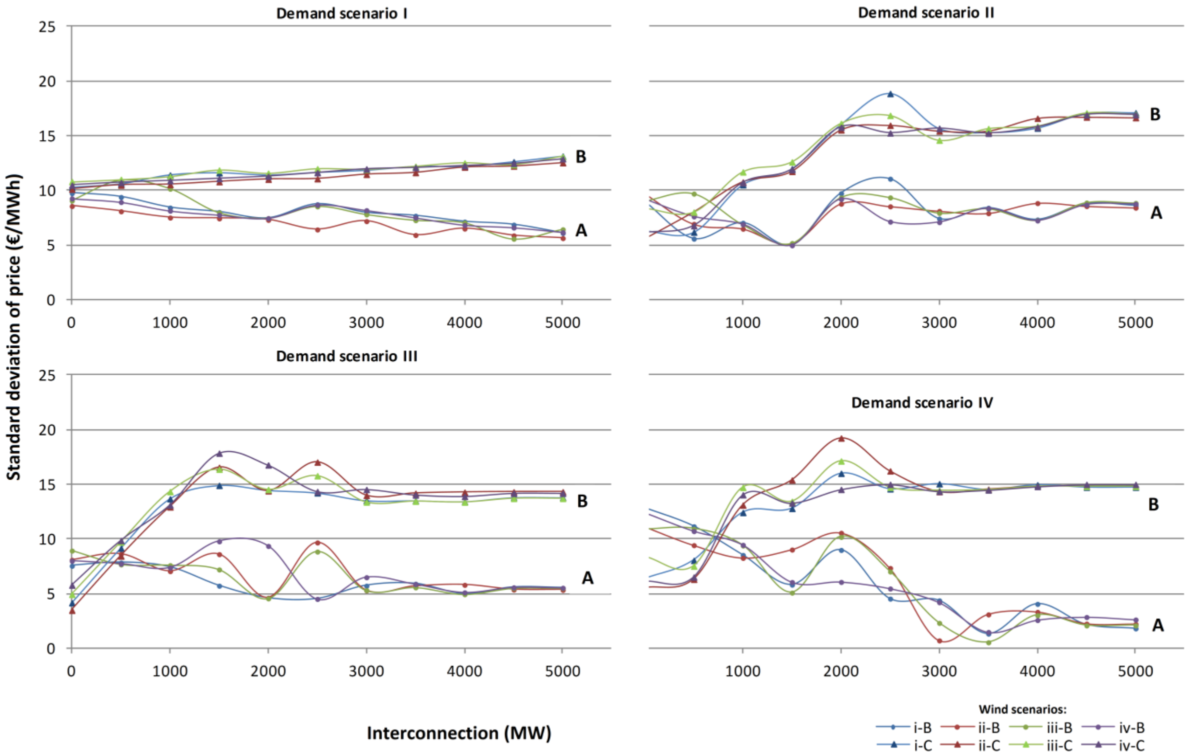

Figure 7: Standard deviation of prices for each demand and wind scenario and region

The standard deviation of prices is seen to increase in region *B* and decrease in region *A*. The previous patterns of saturation at 3000MW for those systems with peak demand of 10000MW are seen again, particularly in demand scenarios II and III. The qualitative pattern of standard deviation of prices is similar across each demand scenario but the quantitative pattern differs. Demand scenarios II and IV, whose demand series have lower correlations, see a lower deviation of prices for both regions at most levels of interconnection. The standard deviation of prices diverges somewhat under different wind scenarios particularly between 2000MW and 3000MW of interconnection. Furthermore different wind scenarios lead to a higher or lower standard deviation of prices in both regions rather than a higher deviation in one region and a lower deviation in the other. Finally it does not appear that a wind scenario with a lower correlation between the two regions leads to a consistently lower deviation in prices for every level of interconnection. Thus while the correlation of demand and wind does bring about different levels of payoff and variance of payoff from interconnection, these effects may be system-specific and general conclusions cannot be drawn.

Case with no variation

In all the simulations above the analysis is performed with a fixed generation portfolio and varying demand and wind scenarios. In order to examine the effect of different conventional generation portfolios, we perform one final set of simulations where there is no variation between the regions by considering the hypothetical situation in which we connect a region to itself. We examine both the fossil fuel based system of Great Britain and the nuclear- and hydro system of France, along with their true demand and wind portfolios. The change in overall payoff is given in Figure 8.

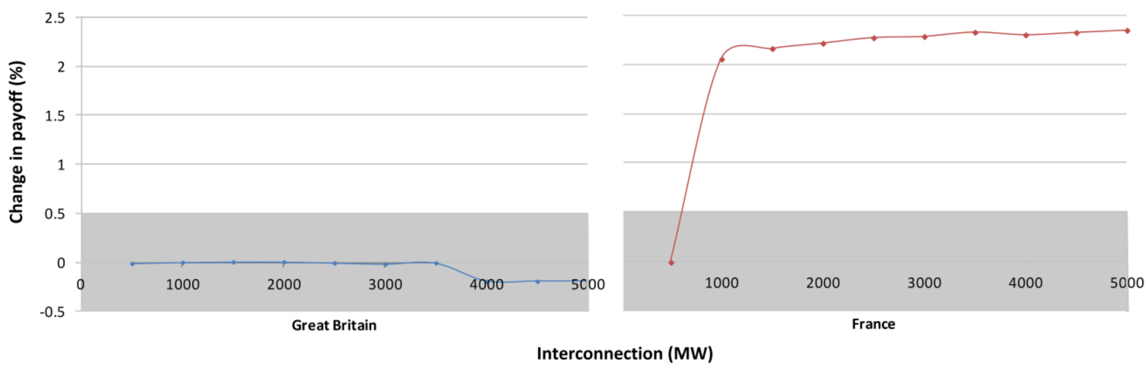

Figure 8: Change in payoff for interconnecting two identical systems

The change in payoff for Great Britain and the change of payoff from 500MW of interconnection in France is within the optimality gap of 0.5% (the shaded region) and so can be ignored. In the case of France the payoff increases once interconnection surpasses 500MW. The change in payoff is much smaller than the changes in payoff seen in demand scenario I (for every wind scenario) in the previous subsection (Figure 3). Thus the difference in generation portfolios is seen to explain the majority of the increase in payoff from interconnection observed when two different systems are interconnected. In terms of the drivers of the (albeit small) change in payoff observed here, the total start costs and no load costs over the whole year are similar for every level of interconnection while generation costs decrease by up to 2% relative to the case with no interconnection. This suggests that increased interconnection allows an increase of capacity factors of lower-cost baseload technologies. It is also found that the timing of unit starts is different as interconnection increases. Over the whole year, the number of and type units started in the two systems remains very similar for every level of interconnection, but the presence of interconnection allows some of those starts to be delayed with the shortfall in online generation capacity compensated for by allowing a lower-cost unit to increase its capacity factor and meet demand in both regions. The change in energy payments for the two regions is shown in Figure 9. The fact that energy payments decrease in both regions indicates that the capacity factors of lower cost generators is increasing, bringing about a reduction in prices. The difference between the two systems arises arbitrarily as the model minimises total costs but there is no term in the objective function which seeks to split costs evenly between the two regions.

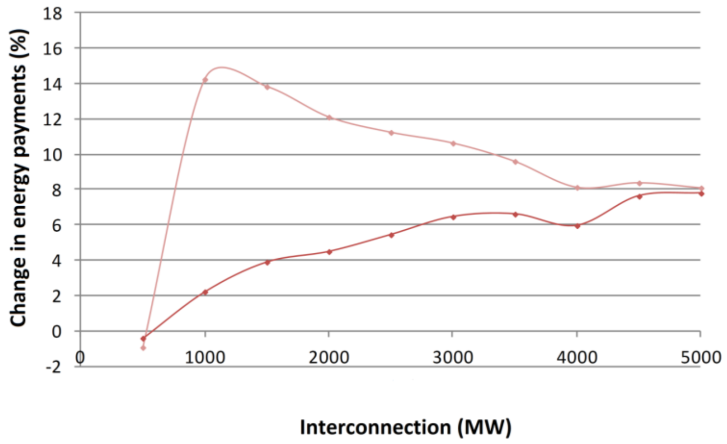

Figure 9: Change in energy payments for interconnecting two identical systems

Figure 10 shows the change in standard deviation of total payoff and Figure 11 shows the change for the individual systems. In the case of Great Britain, the change in total standard deviation is very small and the change of the individual systems displays some symmetry. In the case of France however there is a decrease in the standard deviation of payoff which is more pronounced in one region. This confirms the finding that one region increases the capacity factor of lower cost generation, allowing another region to delay the start of a new unit and causing the generation schedules in the two regions, and their standard deviation, to diverge.

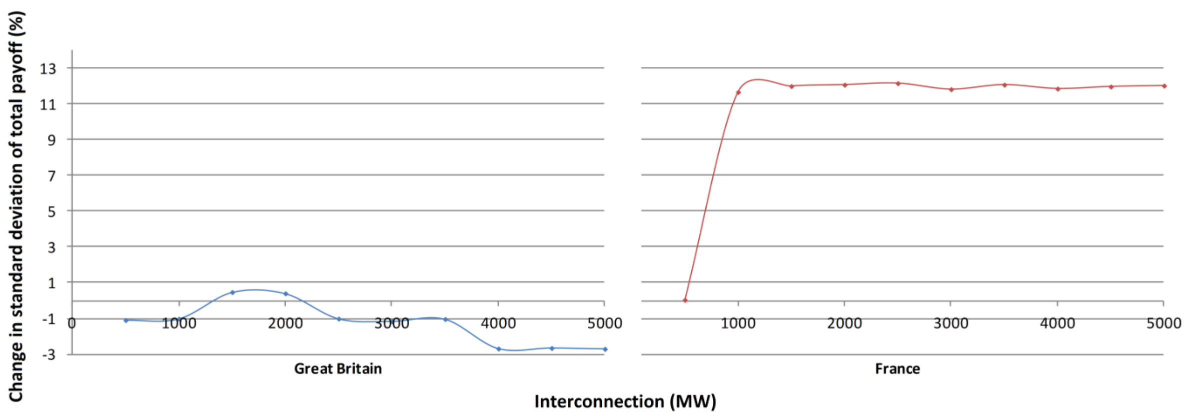

Figure 10: Change in standard deviation of payoff for interconnecting two identical systems

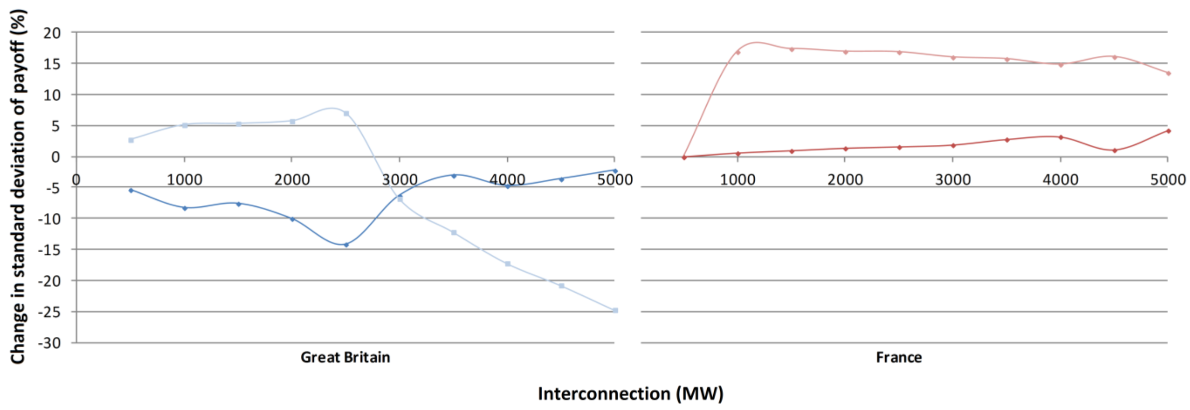

Figure 11: Change in standard deviation of payoff for interconnecting two identical systems

Conclusion

This paper examines optimal levels of interconnection capacity considering both cost minimisation and variance minimisation. It was demonstrated that optimal interconnection levels cannot be analytically obtained *ex ante*. We therefore present a numerical model which can be used to obtain optimal interconnection levels between regions including operational constraints such as start costs and the online status of generation units. Variance minimisation is not included explicitly in the model but is accounted for by varying inputs and considering the effect on the outputs.

When interconnection is included as an endogenous variable there is a negligible level of interconnection investment. This result holds across all demand and wind generation scenarios. This finding is in line with previous results that interconnection investment is a result of supply-side rather than demand-side considerations. When interconnection is included exogenously it is found to decrease costs and thus increase interconnection payoff but this effect saturates at about 30% of peak demand, or 50% of average demand. It is found that the increase in payoff is confined to one region with the other region experiencing a decrease. Furthermore the variability of payoff and prices, as measured by their standard deviation increases in the region which also experiences a decrease in payoff, with a corresponding decrease in variability in the other region. Thus one region gains at the expense of the other in both respects. Different demand scenarios gave rise to the same qualitative but not quantitative results; increases or decreases in payoff were more or less pronounced according to the demand scenario under consideration. Thus the value of an interconnector can vary depending on the level of correlation between the demand on the two systems. In terms of changes in payoff effects, such as energy payments and cost reductions, different wind scenarios did not appear to have a noticeable effect. However varying wind scenarios did bring about some differences regarding the variance of payoff and prices. For the systems considered here there was no discernible pattern to the effect of higher or lower wind correlation on the increase or decrease in variation of payoff.

Eliminating variation by interconnecting two identical regions led to a small increase in payoff and a decrease in the variability of payoff for a nuclear and hydro-heavy system but no change for a thermal-heavy system. The changes observed were still much smaller than those of connecting systems with different generation portfolios. Thus most of the change in payoff appears to arise as a result of connecting systems with varying generation portfolios and not from connecting systems with varying demand and renewable portfolios. The exact effects appear to be system-specific.

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