Assessing cross-border integration of capacity mechanisms in coupled electricity markets

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A B S T R A C T

There is momentum in a number of European electricity markets towards the implementation of national generation capacity mechanisms. This renewed interest in capacity mechanisms raises the question of the cohabitation of both relatively well-integrated short-term energy markets and national generation capacity mechanisms. This paper examines a key issue of generation adequacy policies in a multi-market environment: the effect of foreign generators' and interconnectors' inclusion in national capacity mechanisms. The results show that the absence of cross-border participation could lead to significant social welfare losses associated with over and under-capacity procuring risk. This implies a vicious circle: as capacity mechanisms over or under-procure capacity, cross-border trade of electricity becomes more distorted, which in turn undermines the effectiveness of capacity mechanisms themselves. The findings also show that the inclusion of interconnectors in national capacity mechanisms could induce investments in merchant interconnections by compensating for network externalities and adjusting profit levels on the basis of the interconnection costs. However, despite the participation of interconnectors in capacity mechanisms, the exclusion of foreign generation of this market-based scheme undermines efficiency. In the absence of a wider EU single capacity mechanism, the inclusion of foreign generators and interconnectors in national capacity mechanisms should ensure the most efficient cohabitation of the EU Single Market and national capacity mechanisms.

1. Introduction

To date, a large number of EU members have already implemented a certain type of capacity remuneration policy or are considering doing so to address national generation adequacy concerns.[1] The functioning principles and the pace of implementation of the capacity mechanisms differ considerably from one country to another, as they are being driven by case-by-case scenarios to achieve the best fit to the local requirements. The specifics of market-based capacity mechanisms range from the central buyer solution, such as the capacity auction implemented in GB in 2014, to the supplier obligation solution, such as the decentralised capacity market implemented in France in 2016 (De Vries, 2007; Finon and Pignon, 2008; Cramton et al., 2013). Alternatively, a targeted mechanism for strategic reserves exists or is being installed in several European countries such as Sweden, Finland, and

Poland. Thus, capacity mechanisms can either remunerate all generation or demand contributing to the long-term security of supply (capacity markets), or can contract generation assets that will only be used if markets no longer clear or if the price exceeds a strike price (strategic reserves). These differences suggest that there is no standard design of capacity mechanism and that a consistent European solution for capacity remuneration, therefore, is unlikely in the short-term.

Through the Energy Union strategy (EC, 2015a) and the so-called "Winter Package" of energy laws (EC, 2016a), the European Commission (EC) has raised concerns that the security of supply goal may be undermined by the fact that market design decisions are made at the national level and are weakly harmonised across Europe.[2] The EC is of the view that uncoordinated capacity mechanisms may distort cross-border trade and hinder the achievement of the Internal Electricity Market in Europe. Therefore, market capacity mechanisms must be

open to explicit cross-border participation in order to minimise distortions to cross-border competition and trade, ensure incentives for continued investment in interconnection and reduce the long-term costs of European security supply (ACER, 2013; EC, 2016a, 2016b).

Still from the EU perspective, the Third Package[3] (EC, 2009) promotes the European Electricity Target Model (ETM),[4] which aims to enhance competition by opening the national markets to foreign participants, thereby increasing supply security and cost efficiency. By design, the ETM, optimises cross-border flows by combining the demand and the supply curves for electricity of coupled markets to set market clearing prices, with and without cross-border transmission constraints. Under the ETM, if two neighbouring countries experience a stress event simultaneously, power would tend to flow out of the country with the lowest prices, irrespective of whether that country had called upon its capacity providers to deliver greater supply.[5] However, the cohabitation of the ETM and capacity mechanisms raises concerns about the reliability of the direction of flow for an interconnector during a period of power system stress (RAP, 2013). Because congestion in the interconnections split the collective good "adequacy" between interconnected markets, if power is going to flow according to the ETM it might be difficult for a foreign generator to take on an obligation that is beyond their control (Cramton et al., 2013; Finon, 2014). While the risk of coincident stress events and/or market inflexibilities may be relatively small, these are genuine risks and impact short- and long-term efficiency.

Several possible approaches may be adopted to address the question of the cross-border competition in an interconnected electricity market with capacity mechanisms. These approaches take into account different methods of cross-border participation in capacity mechanisms: i) the statistically likely contribution from interconnectors (i.e. implicit cross-border participation with no trade of capacity rights); ii) the explicit participation of the interconnectors in capacity mechanisms; iii) the actual cross-border participation of foreign generation capacity under heterogeneous capacity mechanism; iv) the actual cross-border participation of foreign generation capacity under harmonised capacity mechanisms and; v) the implementation of pan-European capacity mechanism.

In practice, European countries started implementing capacity mechanisms under purely national schemes without providing for a remuneration of cross-border capacity (e.g. GB, France, Nordic Countries and Italy).[6] The most used approach has been an implicit methodology, which calculates the statistically likely contribution from interconnectors when deciding the domestic generation capacity to procure. However, several countries are currently considering adapting their capacity mechanisms to cross-border capacity participation (AEEG, 2013; DECC, 2013a, 2013b; RTE, 2014; EC, 2015b, 2016b, 2017).

In the GB capacity mechanism, for example, interconnectors are eligible to bid into the capacity auction since 2015 for the delivery year 2019/2020 onwards and have the same obligations to deliver energy than conventional generation capacity.[7] The interconnectors are the

bidding parties and become the holder of a capacity agreement up to the level of the de-rated capacity. They receive the clearing price in the auction and hold the capacity obligation in line with the requirements for the other technologies. This modification in the market design has also raised the interest of merchant interconnectors[8] seeking additional revenues to cover their capital cost. From the public authorities' perspective, it is presented as an opportunity to deal with the lack of interconnector investments, which has been commonly pointed out as one of the main barriers towards an efficient integration of the European electricity markets.

The impact assessment of the interaction of capacity mechanisms in a multi-market environment has been a critical issue for consideration among regulators, policy makers and academics when designing and implementing generation adequacy policies. Although most previous researchers have centred on the heterogeneity of the capacity mechanisms in interdependent electricity markets and the relevance of the cross-border generation participation (Cepeda and Finon, 2011; Finon, 2014; Meyer and Gore, 2015; Viljainen et al., 2013), little attention has been focused on the dynamics of the market interconnection and its impacts on the long-term equilibrium in coupled markets with capacity mechanisms. While externalities generated by the use of the interconnectors for trade between markets, such as deferring generation investments and contributing to reliability, lead to sub-optimality of interconnector investment[9]; this paper argues that cross-border participation in capacity mechanisms partially corrects for these externalities.

The purpose of this paper is to investigate a key issue of generation adequacy policies in a multi-market environment: the effect of both foreign generators and interconnectors' inclusion in national capacity mechanisms. For this, four different cases are examined: (Case 1 – reference case) two inter-linked markets with interconnector and foreign generation participation in capacity mechanisms; (Case 2) two inter-linked markets with interconnector participation but without foreign generation participation in capacity mechanisms; (Case 3) two inter-linked markets without any type of cross-border generation participation in capacity mechanisms; and (Case 4) one energy-only market linked with one market with capacity mechanism without any type of cross-border participation in capacity mechanism. The purpose here is to compare over time the dynamic evolution in two inter-linked markets for these different cases, assessing the economic performances of different policies (e.g. the evolution of the generation technology mix, the reliability criteria, and the overall social welfare).

The analysis relies on a long-term dynamic model of two inter-related markets to assess different cross-border generation adequacy policies. The model is based on Cepeda and Finon (2011) and is expanded to incorporate both strategic bidding behaviour in the energy market and endogenous development of the interconnection capacity. It has been developed using concepts and tools from system dynamics, which is a branch of control theory applied to economic and management problems. This methodology has been extensively used in electricity market modelling to represent capacity expansion planning in wholesale markets (Forrester, 1961; Bunn and Larsen, 1992; Ford, 1997, 1999; De Vries and Heijnen, 2008; Cepeda and Finon, 2011). The following section examines the question of competition among interconnected electricity markets with capacity mechanisms and merchant interconnectors. Section 3 describes the long-term dynamic model of

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[3] The term "Third Package" refers to a package of EU legislation on European electricity and gas markets that entered into force on 3 September 2009.

[4] The ETM is set out in the Framework Guideline on Capacity Allocation and Congestion Management for Electricity (CACM FG) published by the Agency for the Cooperation of Energy Regulators (ACER) in July 2011.

[5] If energy prices reach the same price cap in both markets, there will be an indeterminacy and a tie-breaking rule would be necessary (Mastropietro et al., 2015). It is worth noting that price caps in the day-ahead and intraday markets in Europe were unified under the framework of the Capacity Allocation and Congestion Management Regulation. It has decided to set the maximum and minimum clearing price for single day-ahead coupling to €3000/MW h and − €500/MW h respectively, and for single intraday coupling to €9999/MW h and − €9999/MW h respectively.

[6] The former capacity payment in Ireland considered cross-border participation. The new Irish capacity market will also allow cross-border participation.

[7] Interconnectors were unable to participate in the first capacity auction held in December 2014. Amendments to the Regulations have been laid in Parliament to enable interconnectors to participate in the Capacity Market. https://www.gov.uk/government/

(footnote continued)
news/interconnectors-to-participate-in-the-capacity-market-from-2015.

[8] Merchant interconnectors are considered as a commercial alternative to regulated TSO investments. Unlike regulated interconnectors, merchant interconnectors are repaid through congestion revenues over the interconnector instead of the regulated transport tariff. Merchant interconnectors may be granted exemptions from regulations such as: tariff, regulation, non-discriminatory third-party access and ownership unbundling.

[9] Interconnection investments provide another externality. It reduces market power in the generation market by creating additional options for meeting domestic demand (Stoft, 2002; Stoft, 2006; Borenstein et al., 2000).

two-coupled electricity markets with capacity mechanisms and linked by merchant interconnectors. Section 4 presents the results of the simulations. Section 5 concludes.

2. Competition in interconnected electricity markets with capacity mechanisms

In interdependent electricity markets, generation adequacy should ideally be treated under a common mechanism. In Europe, given the intrinsic differences among the capacity mechanisms in place or others still in the process of implementation, a Pan-European approach seems highly unlikely in the short-term. If a regional implementation is not possible, a unilateral implementation of capacity mechanisms based on a harmonised approach should be the next best option. This solution, however, supposes a co-ordination of the capacity mechanism or co-ordinated exchanges in trading platforms, which seems unrealistic for the same reasons as per for the Pan-European approach. If it is not possible to harmonise capacity mechanisms, the cross-border exchange of capacity rights is assumed to be socially efficient despite the heterogeneity of the different capacity mechanisms (Finon, 2014).

In this context, the discussion focuses on cross-border competition among interconnected markets by considering the potential consequences when capacity mechanisms are introduced in few or all the coupled markets. First, I look at the economic inefficiencies due to the non-participation of explicit or implicit cross–border capacities in capacity mechanisms. Second, I discuss the long-term benefits of the explicit participation of cross-border capacities in local capacity mechanisms.

For the sake of simplicity in this discussion, the term "capacity mechanism" is used to refer to a wide range of mechanisms that make payments for the availability of capacity and encompass three different principles: coordination by price (e.g. capacity payments), coordination by quantity (e.g. capacity obligation, capacity forward auction and reliability option auction), and a command and control approach (e.g. targeted mechanism for strategic reserves) (Finon and Pignon, 2008). Here, the general observations would similarly apply in coupled markets with any of these different adequacy policy approaches.

2.1. Relevance of cross-border participation in capacity mechanisms

The interaction of markets in different zones, and for different products, allows increase of efficiency gains by benefiting from the complementarity of production and demand patterns between markets (e.g. substitution of cheaper generation for more expensive generation). This benefit will tend to increase with the scale and geographical reach of the interconnected markets.

In terms of delivering short- and long-term security of supply, the benefits of interconnection are well known such as the reduction of the ancillary services costs and the deferral of investment in generation (Billinton and Allan, 1996; Cepeda et al., 2009; Newbery and Grubb, 2014; Newbery, 2015). Not taking account of interconnection in the generation adequacy assessment could lead to investment in more domestic generation than necessary, increasing costs for consumers.[10] Conversely, not fully taking account of the fact that interconnections may not always deliver power during a stress event due to power loops flows[11] could signal the need for less domestic generation than

necessary.

As for cross-border trading with capacity mechanisms, excluding interconnectors from participating in a capacity mechanism (directly or indirectly via generators located abroad) would skew investment signals in favour of local generation. Even if it were cheaper to provide capacity to meet security of supply standards by developing more interconnection capacity, investors may choose to develop new local power plants due to the additional investment incentive provided by the capacity mechanism over and above that provided by the energy price. The effect would be to raise the cost of meeting the reliability standard if the lowest cost sources of capacity (across the set of possible generator and interconnector projects) were not developed. In contrast, from a long-term perspective, if the capacity of country A is built because it successfully participated in the country B capacity mechanism, country B benefits from lower costs of reliability, compared to a situation in which only capacity from country B can bid into its capacity mechanism.

Another consideration regards the problem of the credibility of commitment of foreign generators to adjacent capacity mechanisms. A way to deal with this problem is the reservation of interconnection capacity. For example, generation units of country A committed in the capacity mechanism of country B would have a priority access considered by the market coupling algorithm, as if they implicitly had a share in the interconnections, provided that they have bought forward transmission rights (ENTSO-E, 2014a, 2014b). This reservation of capacity might thus ensure the availability of cross-border transmission capacity for foreign capacity providers to meet capacity commitments.

In a more complex approach, in France, explicit participation is based on the fundamental principle that participation in the local capacity market should be organised with the same rights and responsibilities for French and foreign capacity providers alike. As such, the French TSO (RTE) concludes bilateral agreements with each relevant TSO counterpart. These agreements would ensure that adjacent jurisdictions carry out certification, control and penalties on a similar basis to what RTE does in France. In practice, for each adjacent market, RTE would carry out a statistical analysis of the interconnection availability in case of concomitant scarcity which defines the overall explicit contribution of the adjacent market. If there is no agreement between RTE and its relevant TSO counterpart, the interconnector itself would participate directly in the capacity mechanism, offering a volume of certificates equal to their overall statistical explicit contribution. If an agreement is reached, RTE will auction the so-called "interconnection tickets" which foreign capacity providers might bid for once they have pre-certified their available generation capacity. The number of interconnection tickets are equal to the overall statistical explicit contribution. The foreign capacity providers will be certified based on the number of interconnection tickets they can procure in the auction. Then, their certificates can be traded in the French capacity market as per any certificate from a local generator.

Mastropietro et al. (2015) propose an approach whereby capacity nomination would be activated only in case of concomitant scarcity conditions. In any other conditions, electricity would flow towards the country facing the scarcity if there is enough available interconnection capacity.

It is worth noting that although approaches that specifically reserve cross-border capacity for use in scarcity periods might solve the problem of the credibility of commitment of foreign generators, they might lead to interconnectors only offering the remainder in the market coupling. This means that less cross-border capacity is used efficiently. To cope with this issue in the GB capacity market, the government took the decision to let the market coupling algorithm determine the flows and to prevent interconnectors from exerting influence over them.[12]

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[10] For example, in the GB context, the Transmission System Operator, National Grid, determined an expected de-rated contribution from interconnectors at times of system stress for 2019/20 equal to 2900 MW (National Grid, 2015). This amount is a direct reduction of generation capacity to procure for 2019/20 which is, in terms of installed capacity.

[11] Power loop flows occur when a country does not have enough internal grid infrastructure to handle new production, for example from wind, and so the power is diverted through neighbouring countries' grids and then back into a different part of the producing country. Such loop flows have become more common since Germany developed large amounts of wind power in its northern states, but did not develop the grid infrastructure to transfer the output south to where the demand is.

[12] To mitigate any risk of introducing a policy that runs counter to market coupling, penalties are capped at the level of annual payments and interconnectors will not be

Whilst this design might be suitable for a market with capacity mechanisms where only local generators and interconnectors can participate, such as the GB market, this approach is insufficient in capacity mechanisms that allow participation of foreign generators. This is due to the fact that there would not be any assurance their power would flow to the relevant market during scarcity periods.

2.2. Explicit participation of cross-border capacities to fix discrepancies between transmission costs and benefits for merchant interconnectors

Given the additional revenue provided by capacity mechanisms to incentivise new investments, the direct cross-border participation of interconnectors in this scheme inevitably raises the widely known question, and still not fully solved, on investment in interconnection capacity.

In theory, the optimal capacity investment decision made by an interconnector would be that which equates the average spread between marginal cost and revenue with the marginal cost of capacity, whereas the social optimum would be larger, equating the spread price with the marginal cost of capacity. Notwithstanding, interconnection undergoes returns to scale and lumpiness, as well as major externalities, both positive and negative, which leads to underinvestment (Brunekreeft, 2003; Turvey, 2004; McInerney and Bunn, 2013).

On the one hand, returns to scale and lumpiness make merchant interconnectors recover their proportional costs to capacity from the congestion rents but not costs that are independent of the line capacity (i.e. fixed costs). In other words, optimal interconnection investments will simply not generate enough congestion rent to pay for them, which means merchant interconnectors will build less than the social optimal investment (Stoft, 2006). On the other hand, the sub-optimality of interconnection investments comes also from the fact that any interconnector's benefit arises from deferring other investment and from contributing to reliability is an externality, provided that there is no agreement with the system or transmission operator for a contribution to its revenue (Turvey, 2004). Thus, any new interconnection investment allows postponement of investment in new generation in one of the two systems, which it links. This avoided cost for the whole system will constitute a beneficial externality.[13]

On some European borders, merchant interconnector investment decisions are made in response to marked-based incentives such as the congestion revenues, long-term transmission rights[14] and profits from locational arbitrage.[15] However, these revenues might not be sufficient to recover interconnectors' total costs due to network externalities. Additional revenues from capacity mechanisms can become a driver for new investments in interconnection capacity as they partially compensate network externality losses. In turn, additional interconnector capacity increases the economic gains of cross-border participation by allowing a larger participation of foreign generators.[16]

Practically, merchant interconnectors can benefit from capacity revenues through two approaches. First, they can participate in capacity mechanisms by offering de-rated capacity up to the level of their statistical explicit contribution as per the GB (Ofgem, 2014a)[17] or the French capacity markets. Second, merchant interconnectors can also recover capacity revenues through auctions where they offer the overall volume of the statistical explicit contribution to foreign capacity providers, as per the aforementioned interconnection ticket method of the French capacity market.

3. The structure of the model

The model is based on Cepeda and Finon (2011) and is expanded to incorporate interconnector investments, while preserving the essential features of the model: thermal generation modelling and its long- and short-term uncertainties (i.e. demand growth rate uncertainty, generation unit outages and load thermo-sensitivity), reliability modelling, short-term interaction between local electricity markets, anticipation of demand growth and supply in the investment decision process. In this paper, the model integrates interconnectors into the price formation mechanism and into the investment decision process, including strategic bidding behaviour in the energy market and interconnectors' participation in the capacity mechanism respectively.

The main relationships included in the modelling of investments in new generation capacity and interconnectors follow the structure of the causal-loop diagram depicted in Fig. 1. Expected profitability is determined by expectations of future prices, congestion revenues and the payments from the capacity mechanisms. As this additional revenue increases, expected profitability and generation/interconnection capacities raise, thus electricity spot prices decrease. In addition, as long as installed generation or interconnection capacity increases, expectations regarding future electricity prices go down, which in turn lowers expectations of future prices. As a result, the economic attractiveness of new investments is reduced.

3.1. The representation of the coupled electricity market

The modelling of thermal generation, demand curtailment, electricity price formation and reliability are explained thoroughly in Cepeda and Finon (2011). The model distinguishes between the perfect competition framework and the strategic bidding behaviour of the market participants in the energy market. In the former case, electricity producers have no market power, neither in fuel markets nor in the electricity market. Thus, the price is generally settled by the marginal cost of generation, i.e. the variable cost of the marginal technology. If demand exceeds the available generation capacity, the electricity price is set at the value of loss of load (VoLL).

As for the strategic bidding behaviour case, as Eager et al. (2012)

(footnote continued)

subject to greater penalties if they are exporting during scarcity periods.

[13] The only case in which it might not be an externality is when the postponement interconnector makes its prices higher than they otherwise would be, with a favourable effect upon the profitability of the interconnector.

[14] Transmission rights could be either Physical Transmission Right or Financial Transmission Right acquired in a Forward Capacity Allocation. Financial Transmission Rights are either based on an obligation entitling its holder to receive obliging its holder to pay a financial remuneration based on the Day Ahead Market results between two Bidding Zones; or based on an option entitling its holder to receive a financial remuneration based on the Day Ahead Market results between two Bidding Zones. Financial Transmission Rights are part of the Network Code on Forward Allocation Capacity (Entso-e, 2014a, 2014b).

[15] Interconnectors can also provide capacity agreements to traders and generators which provides more secure revenue than the uncertain price differences.

[16] Economic gains through capacity mechanisms cannot be seen as first best solution, which one could obtain from the theoretical centralised approach of the benevolent planner where interconnection and generation capacity are optimised for expected load growth. In fact, because generation is not planned, interconnectors must forecast future

(footnote continued)

generation and load many years in advance to assess their profitability. Thus, merchant interconnectors do not have control or direct knowledge of future generation investments, and face both complex cost structure and network externalities which causes underinvestment without being entirely overcome through revenues from capacity mechanisms.

[17] There are other mechanisms to incentivise new investments in interconnection capacity. For example, the GB energy regulator put in place in 2014 a new regulated route for near term interconnector investment, known as the cap and floor regime (Ofgem, 2014a). Under this approach developers build interconnectors and there is a cap and floor mechanism to regulate how much money a developer can earn. The Transmission System Operator (TSO) will set the levels of the cap and floor ex-ante and they will remain fixed (in real terms) for the duration of the regime. Thus, any revenue earned above the cap will be returned to the concerned TSOs on a 50:50 basis and the TSOs will then reduce their electricity transmission network charges in both countries. If revenue falls below the floor then the interconnector owners will be compensated by the concerned TSOs. The TSOs will recover the costs through their network charges. This regulatory design seeks to reduce risk of exposure for investors while ensuring that excess revenues are returned to the TSOs to benefit GB consumers.
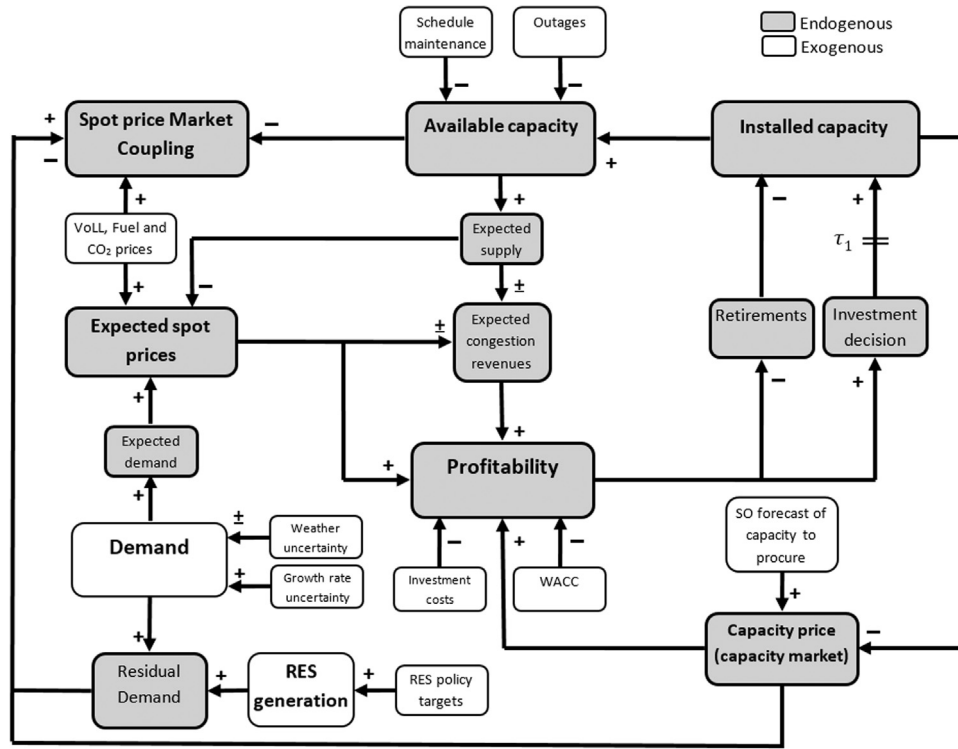
Fig. 1. Causal-loop diagram of a coupled electricity market.

and Hach et al. (2015), I introduce marginal bid curves by allowing price mark-ups as a function of the scarcity of generation capacity. Thus, the model represents a form of exercise of market power in which generators can cover their fixed costs during fewer hours, which means less need for electricity prices set at the VoLL. Precisely, the price mark-up function $\beta(K_m^{t,i,\tau})$ depends on the generation margin $K_m^{t,i,\tau}$ in the price zone i, for the period τ and time step t; which is defined as follows:

$$K_m^{t,i,\tau} = \frac{(\sum_j K_j^{i,\tau}) - L^{t,i,\tau}}{\sum_j K_j^{i,\tau}} \tag{1}$$

where $K_j^{i,\tau}$ is the available capacity of the technology j and $L^{t,i,\tau}$ is demand for the time step t.

Given the generation margin $K_m^{t,i,\tau}$, the electricity price increase due to the strategic bidding behaviour is described as:

$$p_{sb}^{t,i,\tau}(K_m^{t,i,\tau}) = p^{t,i,\tau} \cdot (1 + \beta(K_m^{t,i,\tau})) \tag{2}$$

3.1.1. Modelling investment and capacity mechanisms in coupled electricity markets

In the model, investment decisions in new generation capacity and interconnectors mainly depend on the expected prices, which reflect expected market conditions, which in turn are a function of expected demand and expected generation availability. I model a "forward merit-order dispatch" to calculate the future electricity prices. I implement a second-order smoothing process to forecast the expected growth rate of demand and the available generation for each technology, using a variant of the procedure adopted by Cepeda and Finon (2011). The model calculates these expectations from the built-in function forecasting in MATLAB. In addition, the algorithm of the model verifies the age of all power plants and interconnectors against their economic lifetime and retires all plants for which the age exceeds the lifetime.

In a coupled electricity market with a capacity mechanism, investment decisions depend on the expected revenue jointly earned from the capacity remuneration mechanism and, through sales on the energy

market for generators and congestion revenues for interconnectors. In the model, the capacity market operates three years ahead of real time, with a target corresponding to the peak period of any future year.[18] For the sake of simplicity, the model assumes that there is a vertically integrated generation-supply; interconnectors are independent parties and not vertically integrated; and the TSO is responsible for organising the capacity auction (as per the GB capacity mechanism). On behalf of the suppliers, the TSO buys a prescribed level of available capacity to meet future peak demand and an additional security margin.

The auction mechanism is based on the financial call option principle with a strike price in the energy market acting as a price cap when the option is exerted by the TSO. The model assumes that the price cap or the strike price, given by sp^i, is exogenous and fixed *ex ante* in the model. Thus, while revenues from the energy market are capped over peak-load hours, generators and interconnectors will receive additional revenue from the capacity market according with their de-rating factor.[19] Producers and interconnectors pay a penalty, given by pen^i, when commitments are not met which means that their resources are not available to the system when the TSO requires them.

A rational power generator determines his bid price in the capacity auction $p_{cm,j}^{i,\tau}$ (i.e. his desired premium fee in the auction for availability generation capacity) at the period τ for an amount of $q_{cm,j}^{i,\tau}$ MW equal to the product of the de-rating factor $DF_j^{i,\tau'}$ for the future delivery period τ' of the technology j in the price zone i and the installed capacity $K_j^{i,\tau'}$, defined as follows:

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[18] The model assumes that both generator and interconnectors offer their full available capacity in the capacity market.

[19] The de-rating factor determines the level of capacity agreement that can be secured in the capacity market by a given resource. They are generally set by both Regulators and TSOs from historical and forecasting methodologies. They reflect the different characteristics of the technologies used in terms of maintenance scheduling and outages duration. Unlike generators, de-rating factors for interconnectors are based on future and expected flows. DECC (2015a) provides further details.

$$p_{cm,j}^{i,\tau} = E\left[\sum_{\substack{\forall t \;\to sp^i < \hat{p}^{t,i,\tau'}}} \left[(1-FOR_j^{i,\tau'}) \bullet (\hat{p}^{t,i,\tau'} - sp^i) \bullet \frac{\hat{q}_j^{t,i,\tau'}}{K_j^{i,\tau'} \bullet DF_j^{i,\tau'}}\right]\right]$$

$$+ \; E\left[\sum_{\substack{\forall t \;\to sp^i < \hat{p}^{t,i,\tau'}}} \left[(FOR_j^{i,\tau'}) \bullet (\hat{p}^{t,i,\tau'} - sp^i + pen^i) \bullet \frac{\hat{q}_j^{t,i,\tau'}}{K_j^{i,\tau'} \bullet DF_j^{t,\tau'}}\right]\right] \tag{3}$$

This formulation is similar to Vazquez et al. (2002) and Mastropietro et al. (2016). The first term in Eq. (3) represents the missing money in the future energy market if resource availability commitments are satisfied, since for a generator, the energy price has a maximum value equal to the strike price sp^i. The summation extends to every period where, for the expected aggregated generation $\sum_t \sum_j \hat{q}_j^{t,i,\tau'}$, the expected spot price $\hat{p}^{t,i,\tau'}$ for the delivery period τ' and time step t is higher than the strike price sp^i. The second term in Eq. (3) represents the potential penalties pen^i to be paid when generators are not able to meet their generation availability commitments. $FOR_j^{i,\tau'}$ represents the probability of occurrence of the outages event i.e. when generators or interconnectors are not able to be available for the capacity committed in the auction $q_{cm,j}^{i,\tau}$. We can underline that, on the one hand, the option premium which is required by a certain block of capacity is independent from the generators' production costs and, on the other hand, that it increases as its availability decreases. This means that the more reliable a generator is, the more competitive it will be in this capacity market, and that his competitiveness will not be affected by criteria other than reliability.

As to interconnectors, the hourly profit of the interconnector depends on both the price difference between adjacent markets and the power flow transmitted by the interconnection. Thus, their bid prices in the capacity auction are a function of the future missing money which is based on the congestion revenues $(\Delta\hat{p}^{\tau'} - \Delta sp^i)$; where $\Delta\hat{p}^{t,\tau'}$ is the future spread price between adjacent markets, Δsp is the future spread strike prices between adjacent markets and F'_{i-i} is the expected power flow through the interconnector (i.e. the flow from the zone price i to the zone price $-i$). It is worth noting that the FOR used for interconnectors only relates to technical outages.[20] Consequently, the bid price offered by interconnectors in the market capacity is defined as follows:

$$p_{cm,int}^{\tau} = E\left[\sum_{\substack{\forall t \;\to \Delta sp^i < \Delta\hat{p}^{t,i,\tau'}}} \left[(1-FOR_{int}^{\tau'}) \bullet (\Delta\hat{p}^{t,i,\tau'}\right.\right.$$

$$\left.\left. - \Delta sp^i) \bullet \frac{|F'_{i-i}|}{K_{int}^{\tau'} \bullet DF_{int}^{\tau'}}\right]\right]$$

$$+ \; E\left[\sum_{\substack{\forall t \;\to \Delta sp^i < \Delta\hat{p}^{t,i,\tau'}}} \left[(FOR_{int}^{\tau'}) \bullet (\Delta\hat{p}^{t,i,\tau'} - \Delta sp^i\right.\right.$$

$$\left.\left. + pen^i) \bullet \frac{|F'_{i-i}|}{K_{int}^{\tau'} \bullet DF_{int}^{\tau'}}\right]\right] \tag{4}$$

The capacity price $p_{cm}^{*,i,\tau}$ is determined by the marginal bid (i.e. the highest accepted bid) in the auction mechanism and all the accepted bids receive the desired premium that was solicited by the marginal bid.

Unlike the energy market, the model implicitly assumes that the capacity price is determined under perfect competition. In practice, asymmetric information can result in strategic bidding behaviours, which undermines social welfare. Accordingly, the model neglects further distortions and distributive effects that may occur in the capacity auction.

From the capacity price, the expected profit can be derived for the technology j, given by $\hat{\pi}_j^{i,\tau'}$ (or $\hat{\pi}_{int}^{\tau'}$ for interconnectors), associated with an investment level $K_j^{i,\tau'}$ in generation or $K_{int}^{\tau'}$ in interconnection capacity for the delivery period τ'. This profit will depend on capacity prices, and infra-marginal and scarcity rents earned on the energy market for the generators or congestion profit for the interconnectors:

Generator's annual profit:

$$\hat{\pi}_j^{i,\tau'} = \left[\sum_{\substack{\forall t \;\to \hat{p}^{t,i,\tau'} \leq \; sp^i}} (\hat{p}^{t,i,\tau'} - VC_j^{t,i,\tau'}) \bullet \hat{q}_j^{t,i,\tau'}\right]_{\forall \; \hat{p}^{t,i,\tau'} > VC_j^{t,i,\tau'}}$$

$$+ \left[\sum_{\substack{\forall t \;\to \; sp^i < \hat{p}^{t,i,\tau'}}} p_{cm}^{*,i,\tau} \bullet K_j^{i,\tau'} \bullet DF_j^{i,\tau'}\right] \bullet (1+r)^{\tau'-\tau} \tag{5}$$

Interconnector's annual profit:

$$\hat{\pi}_{int}^{\tau'} = \left[\sum_{\substack{\forall t \;\to \; \Delta\hat{p}^{t,i,\tau'} \leq \; \Delta sp^i}} \Delta\hat{p}^{t,i,\tau'} \bullet |F'_{i-i}|\right.$$

$$\left. - \; OC_{int}^{t,\tau'}\right] + \left[\sum_{\substack{\forall t \;\to \; \Delta sp^i \leq \Delta\hat{p}^{t,i,\tau'}}} p_{cm}^{*,i,\tau} \bullet K_{int}^{\tau'} \bullet DF_{int}^{\tau'}\right] \bullet (1+r)^{\tau'-\tau} \tag{6}$$

where $\hat{q}_j^{t,i,\tau'}$ and $VC_j^{t,i,\tau'}$ are respectively the expected generation and variable cost of the technology j. $OC_{int}^{t,\tau'}$ is the operating cost of the interconnector at the time step t.[21] r is the discount rate. The first term in Eqs. (5) and (6) represents the profit from the energy sold on the energy market when the energy price is less than or equal to the strike price sp^i. The second term in Eqs. (5) and (6) corresponds to the commitment generation payment when the option is exercised by the TSO and the energy price is above the strike price sp^i.

The economic assessment for investing in the installed capacity $K_j^{i,\tau}$ (or K_{int}^{τ}) can be formulated as follows:

$$NPV_j^i = \sum_{\varepsilon=1}^{\varepsilon=T_j^{i,v}} [\hat{\pi}_j^{i,\varepsilon} \bullet (1+r)^{-\varepsilon} - I_j^i \bullet K_j^{i,\tau}] \tag{7}$$

where $T_j^{i,v}$ and I_j^i are respectively the economic life cycle and the annualised fixed cost of the technology j in the price zone i.

3.2. Simulation data

The interconnected electricity system comprises of two interlinked electricity markets. Each adjacent market holds thermal-generating units with four different technologies including nuclear (N), hard-coal (HC), combined cycle gas turbine (CCGT) and oil-fired combustion turbine (CT). The thermal technologies, along with the interconnections, are characterised by outages and schedule maintenance. The parameters used in the simulations for each power plant and interconnection are shown in Table 1.

Data used here are based on available public sources and try to mimic real system characteristics of the GB and French electricity markets. These interconnected markets have been selected due to the current developments as to the participation of interconnectors in the GB and French capacity markets. In addition, the use of real data enables to illustrate simulations results for real size cases.

The investment costs of interconnections are based on the project

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[20] The so-called commercial outages which occur when power flows into the market with lower energy prices are outside the research scope of this article. The outages are modeled relying on the two-state probabilistic model. They are calculated exogenously to the model for a 20-year period on an hourly basis. Unlike demand uncertainties, outages for interconnectors are considered not to be correlated from one year to another or between technologies. It means that the interconnector can fail and be repaired independently of failures and repairs of generation units. The random outages on interconnectors are generated by using the inverse function of a binomial, similar to Cepeda and Finon (2009).

[21] The model assumes a lossless interconnection which implies that the operating cost of the interconnector are independent of the power flow through it.

Table 1
Generation data used in simulations.[a]

		Nuclear	Coal	CCGT	Oil	Interconnection
Initial capacity – GB [MW]		9900	18,900	31,625	1530	2000
Number of plants – GB		9	21	55	18	1
Initial capacity – France [MW]		62,700	2700	6325	6630	2000
Number of plants – France		57	3	11	78	1
Generation capacity per unit [MW]		1100	900	575	85	1000
Overnight cost [£/MW]		4,310,000	2,567,000	1,489,063	1,162,880	400,000
Investment cost [£/MW*year]		348,239	220,257	139,494	108,937	35,531
Variable cost in 2015 – GB [£/MWh]		11.31	27.82	33.91	107.22	–
Variable cost in 2015 – France [£/MWh]		11.31	15.64	28.33	95.50	–
Economic life [years]		60	35	25	25	30
Fuel Intensity [GJ/MW h]		3.6	9.0	6.1	12.0	–
CO_2 intensity [tCO_2/MWh]		0	0.77	0.35	0.73	–
Construction period [years]		6	4	3	2	3
Ramp up [%/(plant*h)] [b]		55	70	100	100	–
Ramp down [%/(plant*h)]		55	70	100	100	–
Forced outage rate		0.042	0.036	0.051	0.041	0.05
Schedule maintenance [% of installed capacity]	Winter	6%	10%	2%	6%	5%
	Spring	29%	33%	12%	23%	5%
	Summer	23%	24%	10%	17%	5%
	Autumn	16%	19%	7%	13%	5%

[a] Data is obtained from IEA (2015) and DECC (2013b). The discount rate and exchange rate are set at 8% and 0.64 £/USD respectively.

[b] Ramping data are based on Hach et al. (2015).

Eleclink[22] (Eleclink, 2013). Right-of-way and the O&M costs are added to complete the total cost of the interconnection. The former are the costs of land and the legal right to use and service the terrain on which the interconnection is located. The O&M costs are regarded as independent of the level in which the link operates and assumed constant through the simulation period.

The model assumes a development of fuel prices for coal, gas, and oil and CO_2 prices (Fig. 2) according to the baseline case projections of the Department of Energy and Climate Change (DECC, 2015b). As to the carbon price, I factor its premium into the short-run marginal cost of the GB generation units. This premium, called carbon price support, creates an artificial spread between the GB and European costs of carbon (Fig. 2). In the model, the carbon cost for the GB generation units is consistent with the carbon price support rate cap at £18/tCO_2 from 2016/17 to 2019/20 (HM Revenue & Customs, 2014). However, as described hereafter, other sets of CO_2 prices values are used for sensitivity analyses purposes.

RES are assumed to be exogenous to the model because it is focused on evaluating the impact of the participation of interconnectors in national capacity markets.[23] I rely on RES production profiles in hourly granularity to include realistic fluctuation and distributions. For offshore and onshore wind and solar PV, I multiply average historical capacity factors by installed capacity. The capacity factors are used according to Cepeda and Finon (2013) and DECC (2015c). I scale these generation capacities up, following the GB and French governments' policy targets for RES and the adequacy forecast of the European Network of Transmission System Operators ENTSO-E adequacy forecast (ENTSO-E, 2014b; DECC, 2015b). The model considers only RES at a transmission level; and embedded generation is shown as a reduction in demand level.

Electricity demand is characterised by a load-duration curve, which illustrates a cumulative distribution of demand levels over each year

Fig. 2. Carbon and fuel prices scenarios.

during the simulation period, and is derived for each market from data on both the GB and French electricity consumptions in 2015.[24] I split the load-duration curve (Fig. 3) in 40 segments of extreme peak hours, and 40 segments of 218 h each for the remaining hours (peak, intermediate and off-peak hours). As discussed above, the models considers two uncertain components affecting demand: its growth rate and thermo-sensitivity.[25] In addition, the available RES energy is discounted from the total hourly demand. The residual demand or net demand is issued when determining the short-term equilibrium price (Fig. 3). The VoLL is set at 20,000 €/MW h in both markets.

The simulations report results for a 20-year time frame (2015–2035). The resolution time-step of the model is one year using the simplifying assumption that investment decisions can only be made at the beginning of each year. To test the level of uncertainty, 10,000 random scenarios, on 20-year period each, are generated through a Monte Carlo simulation method. As discussed above, these random scenarios are generated from long- and short-term uncertainties (i.e. demand growth rate uncertainty, generation unit outages and load

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[22] This project consists in building and operating a merchant power interconnector through the Channel Tunnel to provide a transmission link between the GB and France with a capacity of a 1000 MW in either direction of flow. The total cable length of 51 km inside the Channel Tunnel operating under HVDC system and using symmetrical monopole convertors and land based cables. Eleclink was granted an exemption, subject to certain conditions, from certain aspects of European legislation (Ofgem, 2014b).

[23] The discussion around the RES promotion scheme is outside the scope of this paper. Cepeda and Finon (2013) assess the effectiveness of the capacity mechanism to correct for the negative externalities of large-scale RES development.
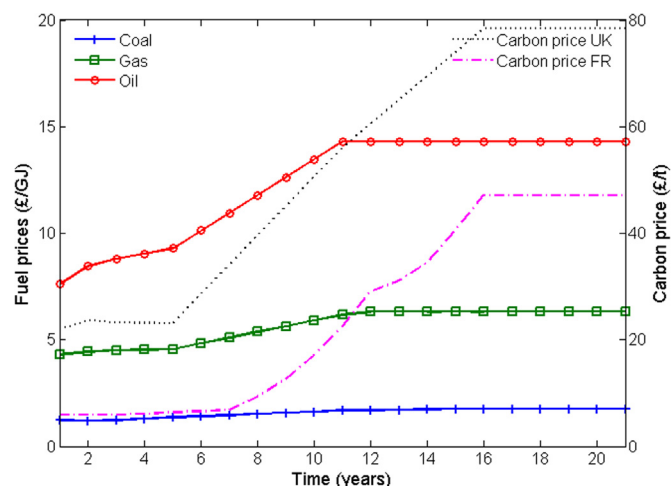
[24] See http://www2.nationalgrid.com/ and http://www.rte-france.com.

[25] These components are modeled and parameterized as in Cepeda and Finon (2011).
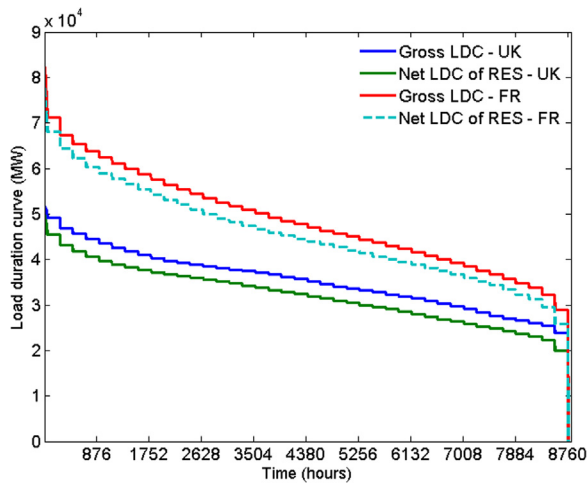
Fig. 3. Load-duration curves of the model at the beginning of the simulation period.

thermo-sensitivity). The presented results correspond to the average results over these 10,000 random scenarios. The model has been developed as a set of programmes using MATLAB version R2016a.

4. Results

4.1. Overview

In the following, I evaluate the investment dynamics in two-interdependent electricity markets by comparing the results for different adequacy policies, which were obtained from running the dynamic capacity investment model with the aforementioned parameters and assumptions. The most suitable combination is the one that ensures efficiency in terms of overall social costs. I analyse four different cases:

Case 1 (reference case). Two inter-linked markets with interconnector and foreign generation participation in national capacity mechanisms.

Case 2. Two inter-linked markets with interconnector participation but without foreign generation participation in capacity mechanisms.

Case 3. Two inter-linked markets without any type of cross-border participation in capacity mechanisms.

Case 4. One energy-only market linked with one market with capacity mechanism without any type of cross-border participation in capacity mechanism.

Case 1 represents explicit cross-border participation of interconnectors and foreign capacity providers in local capacity mechanisms. Unlike Cases 2–4, foreign capacity providers are allowed to participate in adjacent local capacity markets. The model assumes an implicit allocation of the interconnection tickets together with capacity certificates.[26] This approach is currently under discussion for the French capacity market.[27] Case 2 reflects the current design of the GB capacity market where interconnectors can offer their de-rated capacity in the local capacity auction.[28] Case 3 mirrors the French and GB

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[26] For the sake of clarity, in case 1 interconnectors' bids into the capacity market are not simulated. However, foreign generators' capacity certificates are constrained by the expected available interconnection capacity they can procure for the delivery year. The expected available interconnection capacity depends on unplanned outages, uncertainties and future investments/retirements of interconnection capacity. Merchant interconnectors' capacity revenues are calculated as the future spread energy price between adjacent markets for the delivery year.

[27] The regulatory framework of this scenario is now comprehensively described in Section 2.

[28] The bid price offered by interconnectors in the market capacity is defined in Eq. (4).

capacity market design over the first years after their implementation. At the beginning, both jurisdictions implemented implicit participation of cross-border capacity which consisted in deducting the statistically likely contribution of the interconnectors from the target generation capacity to procure. Case 4 represents, for example, the current situation between France which has implemented a capacity mechanism and Switzerland which is an energy-only market.

The purpose of these tests is to compare, for each type of generation adequacy policy, the results between scenarios with different degrees of cross-border participation. As Hach et al. (2015), the simulations consider three groups of performance indicators which are defined to factor the capacity mechanism objectives into the assessment: affordability, sustainability, and reliability. To measure affordability, I report three performance indicators: social cost (i.e. variable, capacity and shortage costs), average annual electricity price and average capacity price. As to reliability, the tests focus on the evolution of the security margin and the expected hours of shortage per year (or loss of load expectation – LoLE). Regarding sustainability, this dimension is derived from the system's annual CO_2 emissions performance indicator.

The model also provides changes in generation portfolio, hours of congestion and price convergence over the 20-year timeframe. In the sensitivity analysis presented at the end of this section, some intermediary cases are studied to verify the robustness of the results.

Fig. 4 depicts the performance indicators for each market as well as for the global performance of the interconnected system. As to total social cost – computed as the sum of the investment in generation and interconnection capacity, production, and outages total costs – simulations show that cross-border participation in capacity mechanisms gives rise to a more efficient outcome (i.e. lower social cost) of the interconnected system (Case 1 – "CMs, I, FG" and Case 2 – "CMs, I") compared to the scenarios where generation capacity is defined as a local product (Case 3 – "CMs" and Case 4 – "CM, EO").

When comparing Cases 1 and 2, the results show that the participation of foreign generation in local capacity markets brings about lower total costs. This suggests that interdependency between capacity markets enables emerging efficiency gains by harnessing the generation portfolio complementarities between power systems. Inclusion of foreign generators in local capacity markets also increases competition in capacity auctions which, in turn, gives rise to lower capacity prices than in the case where only interconnectors can participate.

It is interesting to note that, when referring to the total social cost, the French market does not follow the pattern of the whole regional market. The French market has an excess of generation capacity at the beginning of the simulation and a lower short-run marginal cost of generation, which results in an unequal distribution of short- and long-term benefits of the independence between markets.

On the one hand, GB consumers harness French excess of generation adequacy which gives rise to both lower investments and generation costs in the GB market. On the other hand, the total social cost raises for the French consumers due to its over contribution to the regional generation adequacy as the cross-border participation in capacity markets increases (Case 1 – "CMs, I, FG" compared to Case 2 – "CMs, I").

The average electricity price, which includes the capacity price, reveals the difference caused by presence or absence of cross-border participation in capacity mechanisms. Irrespective of the type of cross-border adequacy policy, coupled electricity markets with identical VoLLs, adequacy criteria targets and capacity mechanisms lead to less shortages compared to a situation where cross-border participation in capacity mechanisms is not allowed. This decrease results in lower average electricity price for coupled markets with cross-border participation, which reflects the reduction of the cost of meeting the adequacy criteria targets. Interestingly, the simulation results show that cross-border participation lead to asymmetric effects on electricity prices. In the GB market, electricity prices fall as cross-border participation increases, which is the opposite of what happens in the French market. This stems from the fact that benefits are unequally distributed
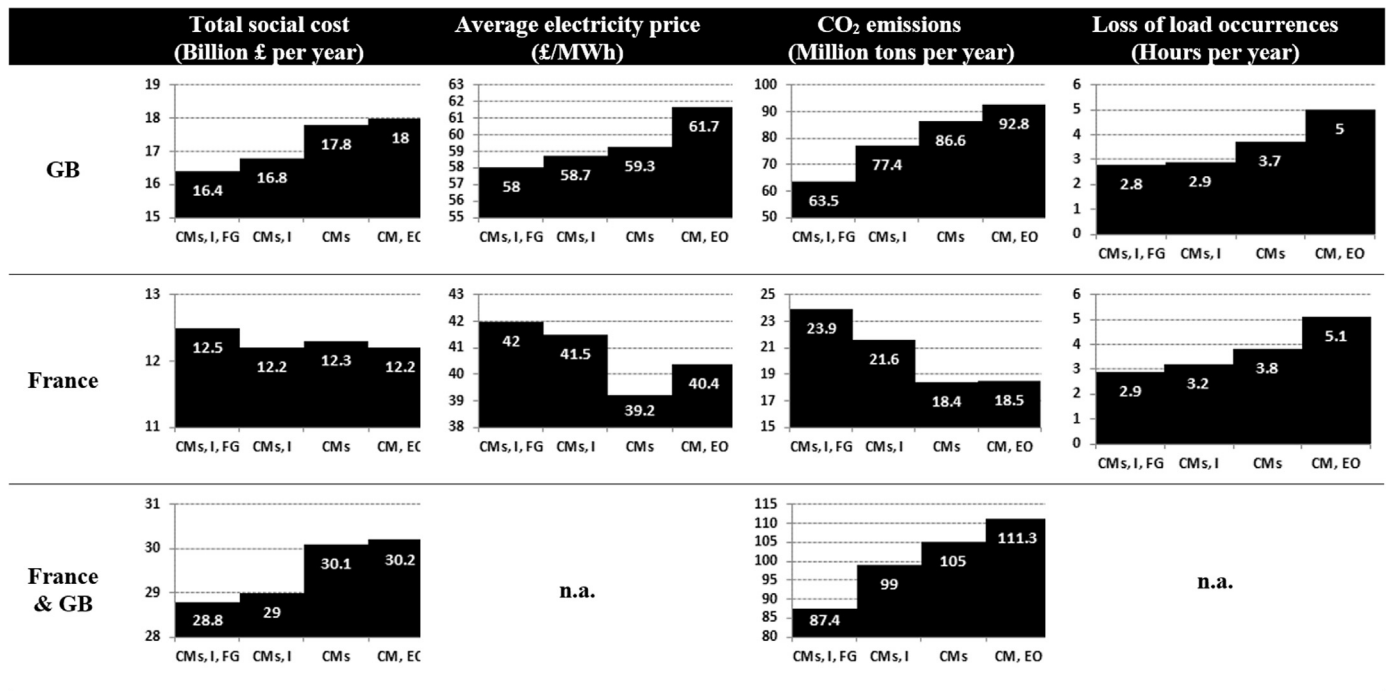
CMs, I, FG (Case 1): two inter-linked markets with interconnector and foreign generation participation in national capacity mechanisms.
CMs, I (Case 2): two inter-linked markets with interconnector participation but without foreign generation participation in capacity mechanisms.
CMs (Case 3): two inter-linked markets without any type of cross-border participation in capacity mechanisms.
CM, EO (Case 4): one energy-only market linked with one market with capacity mechanism without any type of cross-border participation in capacity mechanism.

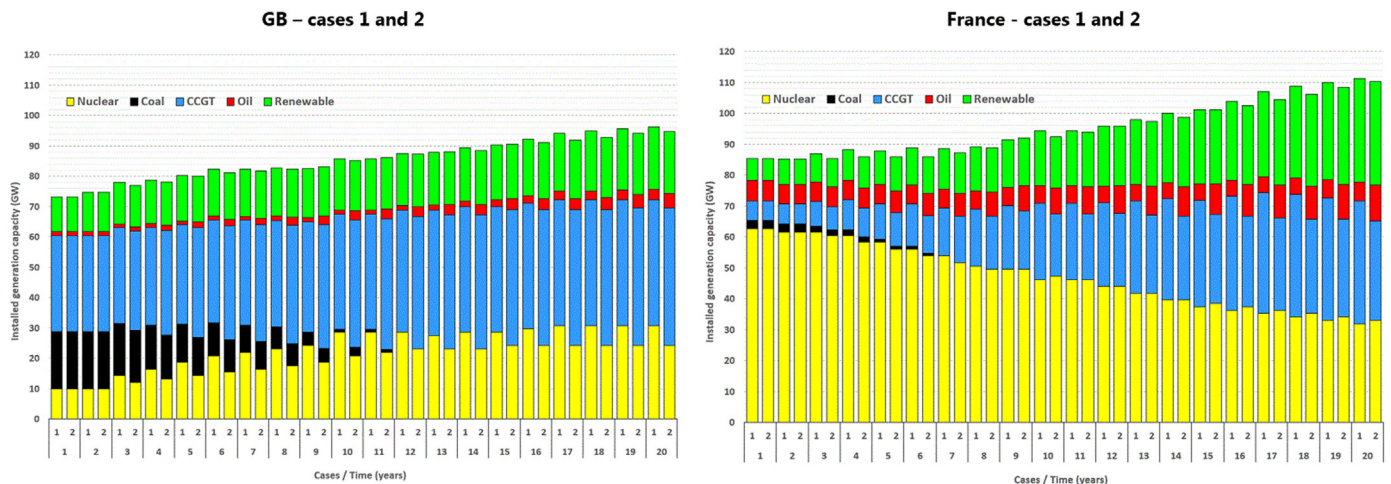**Fig. 4.** Overview of simulation results.

Fig. 5. Changes in generation portfolio in interconnected markets with cross-border participation in capacity mechanisms (Case 1 and Case 2).

due to the differences in generation portfolios between countries and, in particular, the oversupply of generation in the French market at the beginning of the simulation. This asymmetric effect between markets is limited by the available interconnection capacity.

As to the total CO_2 emissions, simulation results also suggest asymmetric effects between coupled markets. In the GB market, cross-border participation in capacity markets reduce CO_2 emissions as: first, French excess generation adequacy contributes to ensure GB generation adequacy which reduces the need for more carbon intensive technologies; and second, coal generation is phased out from 2025 and replaced by gas-fired and nuclear generation (see Figs. 5 and 6). In contrast, CO_2 emissions in France increase due to two reasons. One the one hand, the excess of carbon intensive peak-load generation in France is used to

contribute to supply GB consumers; and on the other hand, the share of electricity from nuclear is significant reduced over time and replaced by gas-fired and RES generation (see Figs. 5 and 6).

It is worth noting that asymmetric distributed effects between countries for the aforementioned indicators stem from differences between generation and demand structures at the beginning of the simulation. Given the long economic life of generation assets, equally distributed benefit would be noticeable once the entire generation fleet in both markets has been renewed. As to reliability, the occurrence of loss of load declines in both markets when cross-border capacity participates in local capacity markets, which reinforces the well-known benefit of interconnected grids for security of supply.
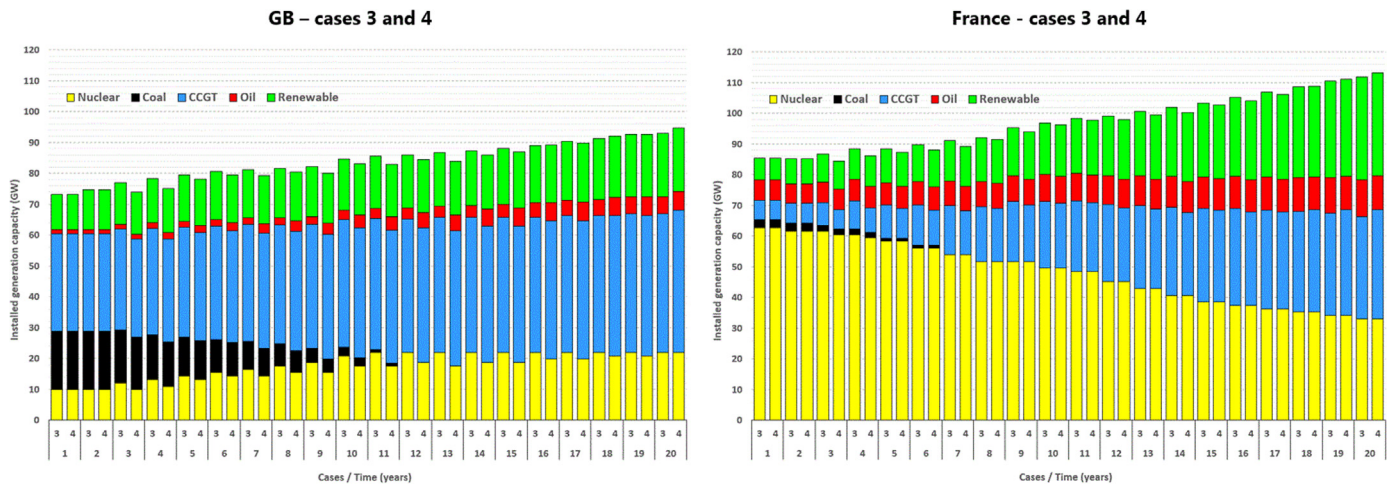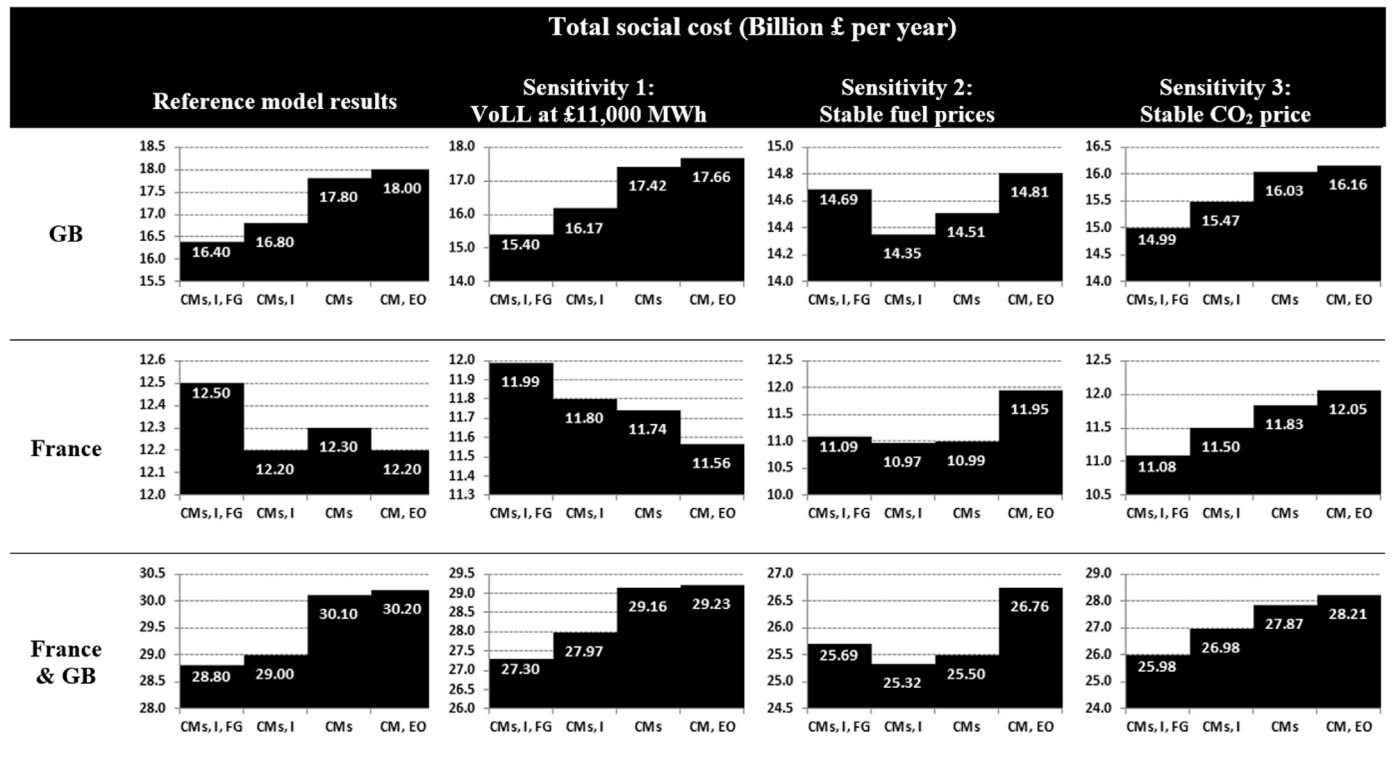
GB – cases 3 and 4

France - cases 3 and 4

Fig. 6. Changes in generation portfolio in interconnected markets without cross-border participation in capacity mechanisms (Case 3 and Case 4).

Total social cost (Billion £ per year)

CMs, I, FG (Case 1): two inter-linked markets with interconnector and foreign generation participation in national capacity mechanisms.
CMs, I (Case 2): two inter-linked markets with interconnector participation but without foreign generation participation in capacity mechanisms.
CMs (Case 3): two inter-linked markets without any type of cross-border participation in capacity mechanisms.
CM, EO (Case 4): one energy-only market linked with one market with capacity mechanism without any type of cross-border participation in capacity mechanism.

Fig. 7. Sensitivity results – changes in total social cost with changes in VoLL, fuel prices and CO_2 price.

4.2. Generation portfolio

For the sake of clarity, explanatory notes are needed to discuss dynamics of the generation portfolio. First, as mentioned in the previous section, RES generation capacity is introduced exogenously.[29] Second, the French government has set a policy target to limit the share of nuclear energy output to 50% of its current level by 2025. This is reflected by the decrease in nuclear installed capacity in the four

scenarios in the French market.

Eventually, as for coal generation in GB, the dynamics of the model considers the GB government's decision on the phase-out of coal power plants by 2025. Hence, no GB coal-fired generation is expected to serve the market after 2025 across all four scenarios.

The Figs. 5 and 6 show the changes in generation portfolio over 20 years in both the French and GB markets. For the Cases 1 and 2 with cross-border participation in capacity mechanisms (see Fig. 5), it is immediately apparent that there is a consistent increase in the share of both nuclear and gas generation in GB over the first 10 years of the simulation period whilst coal generation decreases sharply. However,

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[29] See the top range of the charts in Figs. 5 and 6.

the magnitude of the increase of these two technologies is different when comparing Cases 1 and 2. The inclusion of foreign generation in the local capacity mechanisms (Case 1) lead to a faster growth of nuclear installed generation capacity in GB. In the French market, generation portfolio dynamics is mainly driven by the significant decrease of nuclear generation due to the French decommissioning targets. This fall is compensated by the rise in both RES and gas power generation, with the latter being larger when considering the participation of foreign generation in the capacity mechanisms (Case 1).

As to the Cases 3 and 4 without cross-border inclusion in capacity mechanisms (Fig. 6), it is of note that the surge of nuclear generation in GB over the first 10 years is less significant compared to the cases with cross-border participation. However, in the case when France is assumed to be an energy-only market, we can observe a marginal but gradual increase of GB nuclear generation over the entire simulation period. We see that the technologies in both countries profiting the most from the exclusion of the cross-border capacity are the middle-and peak load technologies with low capital and high marginal costs.

4.3. Sensitivity analysis

I also analyse the sensitivity of the results to assess the robustness of the model with respect to three parameters: VoLL, fuel prices and CO_2 price. The results are depicted in Fig. 7.

First, I test the effect of halving the VoLL value to £ 11,000/MW h. The results show that a lower level of VoLL results in only a slight reduction of total social cost for all the cases. The reason is that a reduction of VoLL implies lower scarcity prices which, however, are offset by an increase of the number of shortage hours. Thus, the simulation results are almost unaltered by changes in VoLL.

Second, the fuel price assumptions are changed by keeping their values constant over the simulation period. Compared to the increasing fuel prices scenario used in the reference model (Fig. 2), this sensitivity can be seen as a decrease in fuel prices. I find that total social cost falls for all the cases. In fact, with the CO_2 being equal, a fall of fuel prices leads to a lower marginal cost bidding in the energy market which reduces social costs. However, the level of this reduction depends on the cross-border adequacy policies. The cases with capacity mechanisms in both markets (Cases 1–3) are more positively affected by lower fuels prices. The reason is that revenues from capacity mechanisms offset for the missing money created by lower energy prices, which are driven by low fuels prices. Thus, interconnected capacity mechanisms ensure enough revenues to invest and adequate generation capacity without further social costs.

In the case with different adequacy policies between interconnected markets (Case 4), the benefits from a reduction in fuel prices are less significant. Structurally, lower energy prices result in less appetite for new investments as investment decisions in energy-only markets are only driven by energy prices. In turn, lower investments lead to both tighter physical margin and higher long-term energy prices with more scarcity hours set at the VoLL, which increases total social costs.

Eventually, as per the fuel prices sensitivity, the CO_2 price is set over the simulation at the level of the first year, which means lower CO_2 prices compared to the reference model (Fig. 2). Under this sensitivity test, global welfare can be increased by implementing cross-border capacity mechanisms.

4.4. Further research

It is worth noting that although the model includes a wide range of features of the GB and French electricity markets, a number of complexities have been left out. Further research should be oriented towards the extension of the presented model to other interconnected markets in order to include the effects of loop flows. Even though the model includes strategic behaviour in the energy market, another area for further research regards to the strategic behaviour in the capacity market. Eventually, a more stylized modelling of embedded generation and demand side response might better mirror the current patterns of the GB and French electricity markets.

5. Conclusion and policy implications

To examine the effects of the inclusion of both foreign generators and interconnectors in national capacity mechanisms, the analysis relied on a long-term dynamics model of two inter-related electricity markets developed by Cepeda and Finon (2011) and expanded to incorporate both strategic bidding behaviour in the energy market and endogenous development of the interconnection capacity.

This paper has argued that the unilateral implementation of the capacity mechanisms could jeopardise the effectiveness of trans-national generation adequacy policies unless there is a cross-border participation in national capacity schemes. Excluding interconnectors and foreign generation from participating in national capacity mechanisms would skew investment signals in favour of local generation and, therefore, would not deliver the benefits of the long- and short-term interdependency across coupled electricity markets.

The simulations show that cross-border participation in capacity mechanisms gives rise to a more efficient outcome compared to the scenarios where foreign generation and interconnectors are not allowed to participate in adjacent capacity mechanisms. The analysis also compares two different approaches of cross-border participation in local capacity mechanisms: interconnectors' and foreign capacity providers' participation. The results show that allowing foreign capacity providers to participate in adjacent capacity mechanisms brings about higher social benefits. The findings also suggest that benefits from cross-border inclusion in local capacity mechanisms through interconnectors' or foreign capacity providers' participation might be unequally distributed in the short-term due to differences between generation and demand structures across coupled electricity markets.

A practical consideration of the participation of foreign capacity providers in adjacent capacity mechanisms regards Governments' and TSOs' verification of foreign capacity providers, including pre-qualification requirements and testing administratively that they can physically deliver their firm capacity commitment. The policy challenge is to overcome this obstacle through a closer coordination among TSOs, which should require clear rules set out in trans-national network codes. But if a coordination among TSOs is not feasible, as shown by the simulations, the participation of interconnectors in local capacity mechanisms might be considered by regulators as a second-best instrument.

Another lesson to draw from the analysis is that inclusion of interconnectors in local capacity mechanisms would induce investment by merchant interconnectors by adjusting their profit level on the basis of the interconnection cost. Although social gains from this approach cannot be seen as a first best, which one could obtain from the theoretical centralised approach by optimising simultaneously generation and interconnection, revenues from capacity mechanisms might partially compensate for network externalities which are one of the main barriers to investment in interconnections. Furthermore, and to a lesser extent, additional interconnector capacity incentivised by capacity mechanisms increases the economic gains of cross-border participation by allowing a larger participation of foreign generators in both energy and capacity markets. Thus, in the absence of a wider EU single capacity mechanism, the inclusion of foreign generators and interconnectors in national capacity mechanisms should ensure the most efficient cohabitation of the EU Single Electricity Market and national capacity mechanisms.

In Cepeda and Finon (2011), we examined the effect of heterogeneous generation adequacy policies between two interdependent markets assuming an exogenous level of capacity interconnection. We went on to show how free-riding behaviour might occur where generation adequacy policies are adopted in one market but not the other.

However, the assumption of exogenous interconnection capacity underpinning this result was strong. Here, the analysis then proceeds to examine the relaxation of this assumption. Taken together, the findings suggest that both homogeneity among capacity mechanisms and cross-border participation in local capacity mechanisms would not only ensure sufficient trans-national generation adequacy but also further allow cost-effective development of the interconnections. The compatibility of capacity mechanisms needs considerable and urgent reform from a cross-border perspective as they can deliver investment decisions, which are made in a relatively short period of time and have not only national but also trans-national consequences for decades.

Nomenclature

Symbol	Description

Indices

τ'	Future delivery period
j	Generation technology
int	Interconnection
τ	Period in years
i	Price zone
t	Time step in hours

Exogenous

I	Annualised fixed cost of the asset
DF	De-rated factor
r	Discount rate
T	Economic life cycle of the asset
FOR	Forced outage rate
OC	Operating cost of the interconnector
pen	Penalty if reliability commitments are not met
sp	Strike price in the energy market
VC	Variable cost of generation
$VoLL$	Value of loss load

Endogenous

K	Available generation capacity
K_{int}	Available interconnection capacity
p_{cm}	Bid price in the capacity auction
L	Electricity demand
p	Electricity price
p_{cm}^*	Equilibrium price in the capacity auction
$\hat{p}$	Expected electricity price
$\hat{q}$	Expected generation available capacity
F'	Expected power flow through the interconnector
K_m	Generation margin
NPV	Net present value
q_{cm}	Offered capacity in the capacity auction
β	Price markup function
π	Profit
p_{sb}	Strategic bidding electricity price

Acknowledgements

Disclaimer

The points of view and opinions expressed in this paper are those of the author and do not necessarily reflect the position of his affiliation (Gazprom Marketing & Trading). Examples of analysis performed within this paper are only to be considered as examples. They should not be used in real-world analytic cases as they are based only on very limited and dated open source information.

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