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Elecxit: The cost of bilaterally uncoupling British-EU electricity trade

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ABSTRACT

The UK's withdrawal from the European Union could mean that it leaves the EU's Internal Energy Market for electricity (Elecxit). This paper develops methods to study the longer-term consequences of this electricity market disintegration, especially the end of market coupling. Before European electricity markets were coupled, different market closing times forced traders to commit to cross-border trading volumes based on anticipated market prices. Interconnector capacity was often under-used, and power sometimes flowed from high- to low-price areas. A model of these market frictions is developed, empirically verified on 2009 data (before French and British market coupling) and applied to estimate the costs of market uncoupling in 2030. A less efficient market and the abandonment of some planned interconnectors would raise generation costs by €700 m a year (2%) compared to remaining in the Internal Energy Market. This result is sensitive to how the British and French electricity systems develop over the coming decades. Economic losses are four times greater (€2700 m a year) if France retains substantial nuclear capacity due to its low marginal costs. Conversely, losses are reduced by two-thirds if UK weakens its decarbonisation ambitions, as lower carbon prices subsidise British fossil fuel generation, allowing electricity prices to converge with those in France. A Hard Elecxit would make British prices rise and French prices fall in three of our four scenarios, with the opposite movements in the fourth scenario.

1. Introduction

Electricity traders sometimes make mistakes, and they know it. To reduce the expected cost of mistakes, risk-averse traders scale back their actions when the direction of trade that maximises profit is unclear. The benefits of interconnecting electricity markets are significantly reduced if the transmission capacity between them is under-used, and sometimes used in the wrong direction. The European Union's Internal Electricity Market is designed to maximise the benefits of interconnection among member states. In particular, market coupling between 20 countries in North-Western Europe uses algorithms to ensure that as much electricity as possible is traded from lower- to higher-priced markets. This has brought significant welfare gains. The British electricity market is one of the 20, but may de-couple itself from the system as a possible consequence of Brexit – the UK's decision to leave the EU. We wish to calculate the cost of this Elecxit.

The European Union's plan to create an internal electricity market started with the deregulation of national electricity markets in the 1990s. The vision of a cross-border market design has been largely implemented by 2015 in the form of the Electricity Target Model (ETM) (ACER/CEER, 2017). In particular, market coupling implies that day-ahead wholesale markets clear simultaneously and transmission capacity is automatically allocated so that electricity can flow from low- to high-priced areas until prices are equalised or capacity is fully used. Trade between Member States is now only limited by capacity constraints of the infrastructure. To tackle this, the EU has set the goal to expand interconnector capacities to 10% of each national electricity generation capacity by 2020 and 15% by 2030.

Until recently, it seemed highly unlikely that the integration of Europe's electricity industry would be reversed, but the UK is in the process of leaving the EU. The EU and the UK have so far negotiated two Withdrawal Agreements, neither of which has (as of October 2019) been approved by Parliament, and a General Election has been called. The outcome of the process is highly unpredictable, given the UK's political circumstances and the breadth and depth of its relationship with the EU.

The complexity of the negotiation is evident in the electricity sector (Mathieu et al., 2018). In addition to the institutions of electricity trading or tariff and non-tariff trade barriers, any readjustment of the emissions trading system, Euratom regulation or the Renewable Energy Directive might have indirect consequences for the electricity sector. Again, the result is not foreseeable. Nevertheless, Brexit scenarios have been developed to help stakeholders prepare and to underpin their

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bargaining positions. Two significant design principles and conclusions from them are presented as examples:

- A number of Brexit scenarios build on the UK Government's rejection of jurisdiction by the European Court of Justice. A UKERC/Chatham House Report[1] suggests that the rejection of this institution excludes British actors from the institutions controlled by them, among others the Internal Energy Market. In particular, the British electricity market could not remain coupled with its continental counterparts.

The resulting uncertainties about the profitability of trading and a reduction of EU funds could hinder the expansion of the trade infrastructure between Britain and the continent (in the context mentioned above) from 4 to 10 GW by 2021 (Froggatt et al., 2017), especially those currently in the planning phase.

- The European Commission has published a scenario for the case that negotiations would not succeed by the date of withdrawal (DG ENER, 2018). Then, the UK would become a 'third country' and 'EU rules in the field of energy market regulation will no longer apply to the United Kingdom'. As consequences of this, the Commission foresees not only market uncoupling, but also the necessity to charge an interconnector usage fee for trade with Great Britain. Whether the latter equals a tariff is not yet obvious.

The current (October 2019) UK government appears to favour leaving the EU Customs Union at the end of a transition period. It hopes to negotiate a free trade agreement for goods while retaining the right to diverge from EU regulations. It is unclear whether the government could have persuaded Parliament to agree to the withdrawal agreement it had negotiated, and a General Election has been called for December 2019, with unusually uncertain consequences. One possible outcome is that the UK leaves the EU, but with genuine attempts to minimise trade frictions. We do not know whether an agreement to retain electricity market coupling is possible, but while uncoupling is not yet inevitable, it is useful to estimate the cost of de-coupling Great Britain from the internal electricity market, and of halting the expansion of interconnectors. Note that Great Britain (England, Scotland and Wales; GB) has a single-zone electricity market which is connected to Belgium, France and the Netherlands on the continent of Europe. This British market is also connected to Northern Ireland (part of the UK) and the Republic of Ireland, which together make up the Single Electricity Market.[2]

For this purpose, the welfare losses are not simply the inverse of the welfare benefits previously gained from European market integration, projected one-to-one into the future. The electricity sector is changing too much for that approach to give realistic estimates. In particular:

1. Before market coupling, trading decisions frequently proved to be uneconomic *ex post*, but their impacts were limited by small interconnector capacities. Interconnector capacity is rising substantially, and future mistakes would have greater opportunity costs than those prevented by market coupling in the past.
2. The structure of electricity generation will change dramatically as more intermittent renewables will enter the market. A higher share of renewable generation will make international coordination more valuable and a lack of coordination costlier.
3. Generation mixes will be adjusted to the higher share of intermittent renewable generation and a change in the load profile. These changes in national supply might also affect the sensitivity of the market price to traded electricity and thus alter the effect of reduced market coordination.

We base our estimates on scenarios for 2030 to show the longer-term opportunity costs of Elecxit. Since an analysis of the costs of market decoupling in 2030 is likely to be unreliable if it is based only on past estimates of the benefits from market coupling, we create a structural model of trading in uncoupled markets that allows us to take account of the three changes above. We assume that the inefficiencies of decoupled markets are solely caused by uncertainties resulting from the separation of auctions of cross border transmission capacities and day-ahead markets. This explanation is supported by survey answers of market participants (European Commission, 2007, pp183–6), it is considered as most important by other authors, e.g. Newbery et al. (2016) and – possibly most important – it enables simulations of trading patterns of decoupled markets in the past that fit well to observed data.

Mahringer (2014) simulates inefficiencies in trading as due to imperfect anticipation of price dynamics, but uses a continuous stochastic process that is not easily adapted for the econometric estimates needed to calibrate our model. Instead, we present a simple but micro-founded two-country trade model.

With market coupling, all markets for delivery at time X close at the same time C and trade can be optimised.[3] If the markets are uncoupled, one of them (D) closes earlier than C. Traders then have to supply and to demand electrical energy and to acquire transmission rights on sequentially closing markets. Trading economically therefore requires price expectations to be formed for the 'not yet closed' markets. As future demand and (especially) intermittent renewable generation are uncertain, prices are also uncertain and trade can only be adjusted optimally to an expected (average) scenario. This trading volume is however suboptimal in (almost) every *ex post* case, causing welfare losses. In extreme cases the direction of trading can even be reversed by the anticipation error. We calibrated the model with generation, load and trading data for Great Britain and France in 2009, when their markets were uncoupled, allowing us to estimate the underlying anticipation error and a possible reduction of the optimal trading volume. We assume that the market design after the market decoupling corresponds to that used for calibration, so that the variance of this basic anticipation error does not change due to changes in the length of forecasting intervals.

With the quantified model, our initial estimate of the benefits of market coupling in 2009 was 50% above values in the literature. This can be explained by the implicit assumption of the standard approach that the trading pattern on uncoupled markets is independent of market rules. While the standard assumption is that arbitrage traders are risk-neutral, our empirical results strongly suggest that traders in uncoupled markets are risk-averse, and that this discourages trade. This increases the gains from market coupling.

Second, we simulate the costs (in 2030) of dis-integrating the British electricity market from France (representing Continental Europe), against the background of the ENTSO-E 2030 Vision 3 scenario "Green Transition". Load profiles, generation capacities and costs are taken from this scenario, with wind and solar output profiles taken from Renewables.ninja (Pfenninger and Staffell, 2016). With significantly higher levels of wind and solar generation, we find that the same underlying anticipation error would lead to trading errors twice as large (in MW terms) as in 2009.

[1] Froggatt et al. (2017), page 18: "Following the UK's decision to leave the EU, it is still unclear whether UK will remain part of current and future market coupling arrangements. This is because these require the active collaboration of GB interconnection counterparts, and market coupling was mostly developed through European legislation (e.g. the European Network Codes on capacity allocation and congestion management (CACM), and on forward capacity allocation (FCA))."

[2] Given this difference, it is ironic that one stated reason for (some of) the opposition to the Withdrawal Agreement was that it might treat Northern Ireland differently from the rest of the UK. We are not attempting to predict the consequences of trying to unravel the integrated electricity trading arrangements on the island of Ireland.

[3] Even though there is residual load uncertainty between C and the time of delivery X we are only interested in additional uncertainties of market closure prior to C.

We compare a business-as-usual reference case, “Soft Elecxit”, with continued market coupling and an increase to 10 GW of interconnector capacity with a “Hard Elecxit”, where the British and French markets are decoupled and interconnector capacity only rises marginally to 5 GW. This raises the cost of generation in the two countries combined by €692 m or 2% of the wholesale market value, compared to the reference case. We find that most of these costs are due to market decoupling, as the net benefits of adding interconnector capacity are low if this simply allows traders between decoupled markets to make greater mistakes. Among the costs of market decoupling, the reduction of trading volumes due to risk aversion is more important than trading errors based on imperfect information. British generators produce more power, and French ones less, if a Hard Elecxit cuts trade, which means it would raise prices to British consumers (by €861 m) and reduce those paid in France by €870 m. Carbon dioxide emissions rise by 10 million tonnes.

The costs of Elecxit are sensitive to the evolution of the electricity systems on each side of the Channel. If both France and GB followed the “Slow Progress” ENTSO-E Vision 1, there would be less investment in renewable generation, and France would retain more of its low marginal cost nuclear reactors. There would be greater price differences between the two markets, greater opportunities for trade, and greater costs from disrupting it – around €2.7 billion. We also consider hybrid scenarios in which France follows the Green Transition but Britain reverts to Slow Progress. If this involves a lower British carbon price, our assumptions lead to similar wholesale prices in each market, relatively small gains from trade, and relatively small costs to disrupting it – €217 m, even after valuing the additional emissions at the EU carbon price. The EU might impose a border carbon tax, which would make its generation relatively more competitive in the British market, and trade more attractive. A Hard Elecxit in those circumstances would cost €816 m.

Following this introduction, the second section presents an overview of the effects of decoupled electricity markets and discusses their causes. On this basis, Section 3 sets out a model of rational trade in decoupled electricity markets. The model developed is then applied in Section 4. First it is conditioned for empirical treatment in Section 4.1 and econometrically estimated for 2009 data in 4.2. The quantified model is used to estimate the benefits of market coupling in 2009 ex post, using the methods described in Section 4.3. We present our results in Section 5, with some more general conclusions in Section 6.

2. What is wrong with uncoupled electricity markets?

In general, two markets can be defined as uncoupled if market rules exclude a conditioning of supply and demand in each of the markets on the price of the other market. This might be caused by different market closure times, by the necessity to submit unconditional demand or supply prices to the auctioneer or it might simply be forbidden to receive the relevant information. There could also be different regulatory requirements that impede trade directly, or make one government reluctant to facilitate it.[4] While in general this lack of information reduces allocative efficiency, it should be pointed out that market coupling increases transactions costs, in particular those of communications infrastructure,[5] and it complicates the search for an integrated market equilibrium. Whether markets should be coupled or not is thus a quantitative question of costs and benefits. In electricity market equilibrium, arbitrageurs in coupled markets fully equilibrate competitive prices, as far as allowed by transmission capacity constraints.[6] This maximises short-run welfare, and should be compared with the outcome when markets are not coupled.

2.1. Uncoupled markets

While adjoining electricity control areas typically exchanged power, the early wholesale markets were uncoupled. To trade power between two adjacent markets, a company would need to reserve transmission capacity on the interconnector between them, buy power in one market, and sell it in the other. Much transmission capacity was sold in advance in long-duration blocks, and the quantity available in each direction was limited to the maximum capacity of the interconnector. There was often no mechanism for releasing additional capacity to the market if the holder did not want to use their rights, or if electricity flowing in the other direction created spare capacity on the lines (easily possible in an AC network).

If one market publishes its results before the deadline for submitting bids to the other,[7] traders would at least know whether they now have to buy or sell power in the second market, or if they came away from the first auction with nothing. However, the time difference between the two markets' deadlines means that new information on demand and generators' availability, and hence on expected prices, is likely to arrive after the first set of bids are submitted. The trader may now be committed to selling power into a market newly expected to have a surplus, and therefore face a loss.

But even if the market deadlines are identical, so that all bids will be based on the same information set, individual traders will only know part of it, and so the only way to be sure of not having un-matched commitments is to submit one unconditional bid to buy and one unconditional offer to sell. This ensures trade, whatever the price combination on the two markets. When price differences are large and systematic, this strategy may be consistently successful, but if the two markets have similar prices, a trader who is unlucky in the individual information will commit to a trade that turns out to be unprofitable. It is unlikely that arbitrageurs could gather all the information needed to prevent this.

2.2. Coupled markets

If the markets are coupled, the system operators take over the role of cross-border traders. The markets close at the same time, so all bids and offers are drawn from the same information set. Computer algorithms move power from a lower- to a higher-priced market until the prices are equalised or interconnector capacity is fully used. All generators and buyers face the price in their local market, and the difference between those prices creates revenue for the interconnector owners. Since all market participants' information is used to derive all prices, this should increase market efficiency, although market coupling also increases transactions costs.

However, equilibrating prices is not possible if the capacity limit of the transmission infrastructure is reached: i.e. either prices in both markets are the same and the trade volume is below capacity or prices are not equal and there is no unused capacity available. This “ideal trading” pattern takes the form of a step function in terms of price differences and utilisation of the trading capacity (the red curve in Fig. 1). Day-ahead prices for GB come from APX, and those for France from EPEX France. Trade volumes are from RTE, as are the interconnector capacities in 2009 and the French loads (used later). The 2017 interconnector capacities (also used later) are given by N2EX Market Coupling Capacities. Loads in GB are from National Grid via Elexon.

However, in uncoupled markets (e.g. between France and GB in 2009), frequent and strong deviations from this ideal trading pattern are found (blue dots, Fig. 1). Price differentials persisted for a large

[4] An anonymous referee has emphasised the EU rules that electricity interconnectors must follow, including the jurisdiction of the European Court of Justice, which is unattractive to many UK politicians.

[5] NAO (2003) estimates the additional infrastructure cost for the ‘new electricity trading arrangements (NETA)’ in England and Wales at £116 million for the first 5 years and £30 million per year thereafter.

[6] The algorithm for determining local market prices under Euphemia contains the optimal trading strategy of an arbitrageur. To further investigate this strategy, we explicitly introduce this actor, although under Euphemia there is no longer any physical counterpart.

[7] A detailed description of market rules can be found in Madlener and Kaufmann (2002).

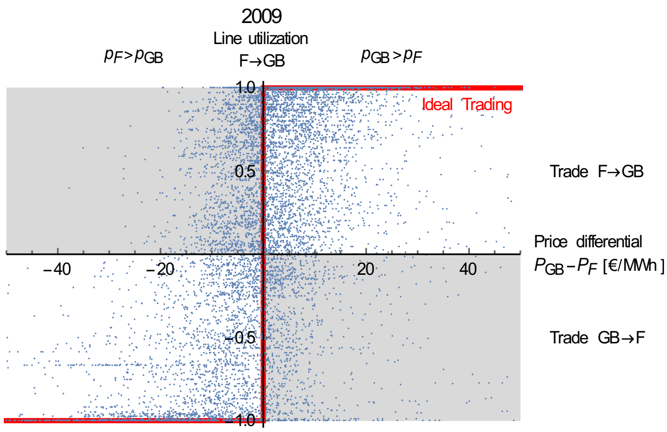

Fig. 1. GB France trading pattern – before market coupling: hourly capacity utilization of the France GB interconnector vs. hourly price differentials on the day ahead markets in 2009. Grey shaded areas indicate trading against the price differential.

number of trading periods without binding capacity restriction. It is clear that the trading potential was often not used efficiently. In 30% of periods, electricity was bought in the market with higher prices and sold on the market with the lower prices. At these times, simply not trading would have been welfare-enhancing. Ehrenmann and Smeers (2004) and Bunn and Zachmann (2010) discussed possible reasons for the under-utilisation of interconnector capacity:

1. Uncertainties from the separation of transmission and energy markets. Transmission auctions usually preceded the energy markets,
2. System operators may have need to be active in scheduling cross-border flows for congestion and system balancing purposes and
3. Strategic trading by generators with market power (generators would trade against the price differential, selling into a cheaper market to raise demand and price in their home market).

The impact of uncertainties caused by separating the allocation of transmission capacity and local electricity markets are well documented. To quote the European Commission's Energy Sector Inquiry (2007, p. 184), "the deadline for interconnector nominations occurs after the French (Powernext) energy market clears, while the UKPX (the leading UK power exchange) is open." Under these market rules[8] market participants confirmed in a poll "that they faced uncertainty since they had to place auction bids based on expected wholesale market prices." (p. 185)

Market coupling would remove uncertainties due to separated markets, and make trading against the price differential impossible. Therefore, the past welfare losses of uncoupled markets (and short-term welfare gains from market coupling) could simply be estimated by comparing the observed trade pattern to the ideal pattern and evaluating the differences.

In the simplest form applied by ACER (2013), interconnector utilisation was artificially increased to 100% at existing price differences, while the advanced version (Newbery et al., 2016) also took account of price convergence due to higher utilisation. The uncoupled and ideal allocations could then be compared by welfare measures based on local supply and demand. 'Before and after' estimates of day-ahead market prices quantify a price drop that induces a welfare gain of 0.25–0.5% of the wholesale market value (Newbery et al., 2016). Further estimates are summarised in Table 1. It is implicitly assumed that the willingness to trade is independent of market coupling, an assumption challenged by our estimates in Section 4.2.

These estimates have motivated regulators to gradually couple European electricity markets, until almost all the markets of north-

Table 1
Overview of estimates of market integration benefits.

System wide estimates		
Newbery et al. (2016)	Considering price changes from market coupling across the EU	day-ahead market coupling 0.25–0.5% wholesale value day ahead Intra-day and balancing benefits €1.3bn/yr. Total benefits including removing unscheduled flows could be €3.9bn/yr
Mansur and White (2009)	Compare prices before and after a bilaterally cleared zone joined PJM's market area to estimate price spreads and welfare gains	0.7% wholesale value
Single interconnectors		
Meeus (2011)	Compare flows and determine welfare gains on the Denmark-Germany Kontek cable with no coupling and one-way market coupling.	Welfare gain €10 m/yr or €17 m/GWyr, ≫Mansur and White (2009) estimates
SEM Committee (2011)	Estimate welfare gains of coupling the interconnectors between GB and the Single Electricity Market (SEM) of Ireland (950/910 MW imports/580 MW exports)	€30 m/yr for import capacity of 930 MW, €32 m/GWyr, ≫Meeus (2011) estimates
National Grid (2015)	Sharing reserves over interconnectors might reduce capacity needs by 2.8 GW	With 2014 capacity auction price of 19.40/kWyr: €15 m/GWyr = Meeus (2011) estimates.

west Europe with 19 countries and 85% of the European power consumption were coupled by 2015 (Table 2). The Single Electricity Market covering Ireland and Northern Ireland was added in October 2018.

Indeed, the trading pattern for the implicitly auctioned net daily inter-connector capacity on the France-GB border and the hourly price differential between UKPX and EPEX in 2017 (Fig. 2) closely fits the ideal trading pattern. As described above, either the prices are practically equilibrated[9] or the capacity restriction binds.

As market coupling resolved almost all possible reasons for inefficiencies and transformed the observable allocation from distorted to ideal, it was not necessary to evaluate the actual sources of inefficiency when estimating the gains from coupling. We cannot simply take the reverse of these gains as an estimate of the cost of market uncoupling from Elecxit, as the conditions will differ strongly in a future sustainable electricity system with higher shares of renewables, higher transmission capacities and adjusted generation structures. To improve accuracy, it is necessary to model the counterfactual of decoupled markets. This is different in principle to the modelling of market coupling as the ideal allocation is the 'business as usual' and the distorted inefficient allocation must be constructed actively. Therefore, the reason for the inefficiencies of uncoupled markets must be made explicit. We interpret the wide geographical extent of trading inefficiencies when explicit interconnector capacity auctions close before at least one electricity market as evidence that uncertainty is the most important cause of inefficiency, and focus our analysis on this.

[8] Details on the market rules can be found in Madlener and Kaufmann (2002).

[9] There are small fees to cover the electricity lost on the DC interconnector and at the AC-DC conversion stations, and so a small price difference is needed to cover these and make trading worthwhile – the EU market allocation algorithm takes account of this, as shown in Fig. 2.

Table 2
Stepwise integration of European electricity markets. Data from EPEX Spot.

1996	**Nordpool:** Norway Sweden							
1998	+ Finland							
2000	+ Denmark							
2006		Tri-Lateral Market Coupling (**TLC**): France, Belgium, Netherlands, (Luxemburg)						
2007			**MIBEL** Spain Portugal					
2010	**Central West Europe** (CWE)			Germany, Austria	Poland, Latvia, Lithuania Estonia			
2011						+GB		
2014	**North Western Europe** (NWE)							**4M** (CEE): Hungary, Slovakia, Czech Republic, Romania
2015							+ Italy Slovenia	
2018							+Ireland	

3. Trade equilibrium in uncoupled markets

We develop a model of profit-maximising bilateral trade between France (subscripted F) and Great Britain (subscripted G) in uncoupled day-ahead markets with trading losses and capacity constraints. First, a trading equilibrium in coupled markets is defined (Section 3.1). Then (Section 3.2) we study its structural properties graphically and based on these an algorithm for its computation is derived. We then introduce uncoupled markets (Section 3.3) with anticipation errors and show how to modify the previous analysis.

The trading volume T_h is defined as the net electrical energy imported into GB (for $T_h > 0$); exports from GB are shown as negative values of T_h. Due to losses (equal to a proportion τ of the traded electricity) France would have to export $T_h/(1-\tau)$ units in order to deliver T_h in GB. If GB is exporting T_h units of electricity, then $(1-\tau)T_h$ units can be sold in France. If we define transmission capacity symmetrically ($K_h = \overline{K}_h$) in terms of the electrical energy entering the exporting conversion station (that is, before losses), GB imports are restricted to no more than $(1-\tau)\overline{K}_h$ and exports to no more than K_h. The function $\varphi(T) = (1-\tau)^{sign(T)}$ simplifies the notation significantly.

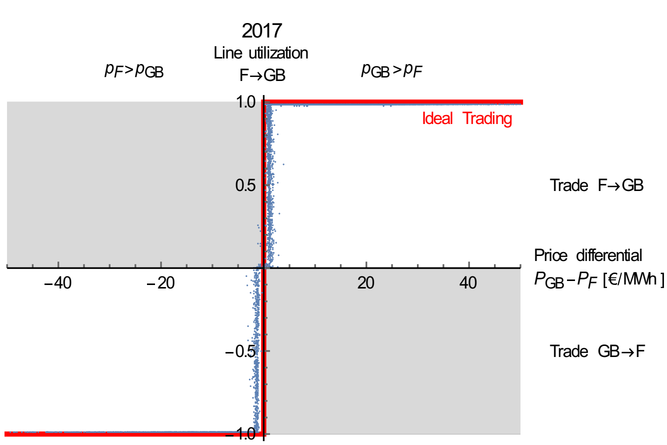

Fig. 2. GB France trading pattern – under coupled markets: hourly capacity utilisation of the France GB interconnector vs. hourly price differentials on the day-ahead markets in 2017.

3.1. Trading equilibrium with losses

We first describe an equilibrium model of optimal bilateral trade in uncoupled day-ahead markets. To keep things simple, we do not consider the allocation of interconnector capacity among traders but assume the existence of a representative price-taking trader (arbitrageur). A trading equilibrium is a vector of French and British prices and a trading volume $(p^*_{F,h}, p^*_{G,h}, T^*_h)$ in every hour h such that the price-taking arbitrageur maximises its profits, and given these prices the induced supply and trade equal local load.

Demand in each market is given by $L_{G,h}$ and $L_{F,h}$, known in advance and unaffected by price. All markets are perfectly competitive thus marginal costs of generation equal market prices. Market supply can be described by $C_{G,h}'^{-1}(L)$ and $C_{F,h}'^{-1}(L)$, the inverses of the aggregated marginal cost functions $C'(L)$. The underlying cost functions C are assumed to be monotonic and at least twice differentiable. To cover seasonality of the supply,[10] C' depends on h. In our estimation and simulations, we use 8 half-seasons.

Furthermore, we assume that there is short term information $\varepsilon_{G,h}$ and $\varepsilon_{F,h}$ known to all market participants that shifts the supply curve. These supply curve residuals are distributed normally with standard deviation σ_G and σ_F. Market clearing on the two markets implies

$$C_{G,h}'^{-1}(p_{G,h} - \varepsilon_{G,h}) = L_{G,h} - T_h \tag{1}$$

$$C_{F,h}'^{-1}(p_{F,h} - \varepsilon_{F,h}) = L_{F,h} + \varphi(T_h)T_h \tag{2}$$

The calculus of the profit maximising, representative, price-taking arbitrage trader that shifts T British units of electricity from France to

[10] Maintenance is concentrated in the summer months. Ofgem, 2012 (page 27, Fig. 3.1) reports that coal fired power plants are 26% more available in winter than in summer - respectively gas CCGT (+17%), OCGT (+14%) and nuclear (+12%). Gas prices are also seasonal.

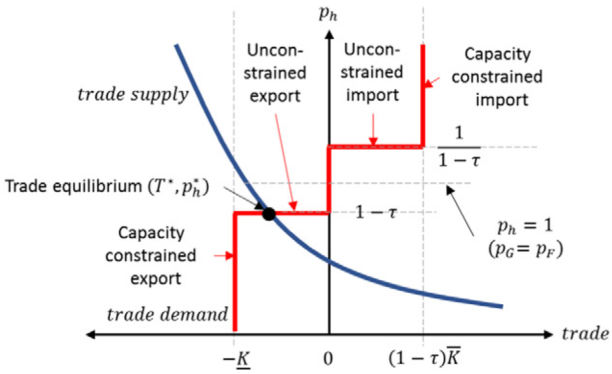

Fig. 3. The structure of the trade equilibrium induced by trade demand and trade supply. Note that p_h is a price relation and thus supply and demand are graphical representations but not conventional demand or supply.

Great Britain restricted by a transmission capacity K is

$$\begin{aligned} &\max_T \pi_h^{Arb} = (p_{G,h} - \varphi(T) p_{F,h})T \\ &ts.t.: -K_h \le T \le (1-\tau)\overline{K}_h \end{aligned} \tag{3}$$

The optimal trade is a set-valued mapping from the prices $p_{G,\,h}$, $p_{F,\,h}$ to the admissible trade levels

$$T^*(p_{G,h}, p_{F,h}) = \begin{cases} (1-\tau)\overline{K}_h & p_{G,h} > p_{F,h}(1-\tau)^{-1} \\ (1-\tau)\overline{K}_h, 0 & p_{G,h} = p_{F,h}(1-\tau)^{-1} \\ 0 & (1-\tau)^{+1} < p_{G,h}/p_{F,h} < (1-\tau)^{-1} \\ -K_{-h}, 0 & p_{G,h} = p_{F,h}(1-\tau)^{+1} \\ -K_{-h} & p_{G,h} < p_{F,h}(1-\tau)^{+1} \end{cases} \tag{4}$$

3.2. Equilibrium analysis

The structure of the equilibrium can be analysed graphically using the price relation $p_h = p_{G,\,h}/p_{F,\,h}$. With this definition (4) can be simplified to the trade demand (set-valued mapping) $T^*(p_h)$. A trade supply can be derived by inverting market balancing conditions (1) and (2) for the local prices

$$p_{G,h}(T) = C'_{G,h}(L_{G,h} - T) + \varepsilon_{G,h} \tag{5}$$

$$p_{F,h}(T) = C'_{F,h}(L_{F,h} + \varphi(T)T) + \varepsilon_{F,h} \tag{6}$$

and plugging (5) and (6) into the definition of p_h. The trade supply derived from (5) and (6) and the optimal set (derived from 4) are shown in Fig. 3. It is straightforward to see that there exists exactly one equilibrium and that it can be determined with an algorithm to check which section of the demand has an intersection with the supply[11]: Check whether there is a no-trade-equilibrium. If not, determine the trading volume that equilibrates marginal costs (net of trading losses). If this volume is within capacity constraints then it is the trading equilibrium. If not, the binding capacity is the equilibrium trading level.

This algorithm can be expressed more formally with the unconstrained latent equilibrium trade volume T_h^L, which would equalise prices (net of losses) in the absence of capacity constraints, implicitly defined as:

$$\begin{aligned} &0 = F\left(T_h^L\right) := \begin{cases} pd\left(T_h^L, -1\right) & pd(0,-1) > 0 \\ T_h^L & pd(0,+1) < 0 < pd(0,-1) \\ pd\left(T_h^L, +1\right) & pd(0,+1) < 0 \end{cases} \\ &pd\left(T_h^L, s\right) = p_{G,h}\left(T_h^L\right) - (1-\tau)^s p_{F,h}\left(T_h^L\right) \end{aligned} \tag{7}$$

In the presence of capacity constraints, T_h^L (latent trade) will not be observed directly but instead the capacity-censored $((1-\tau)\overline{K}_h > 0 > -K_h)$ equilibrium with trading volume T_h^*

$$T_h^* = \begin{cases} (1-\tau)\overline{K}_h & T_h^L > (1-\tau)\overline{K}_h \\ T_h^L & else \\ K_{-h} & T_h^L < K_{-h} \end{cases} \tag{8}$$

Thus, the trade equilibrium with losses and capacity constraints can be determined by solving Eqs. (5)–(8) for different loads, cost functions and short term information.

How well does this model fit to the trade measured in a coupled market environment in 2017? To provide a first impression eight equally long half-seasons during the year were considered reflecting the seasonal structure of generation capacity that supports high prices with low capacity available in low demand summer. For each of these half-seasons a supply curve ((5) and (6)) has been estimated with 2017 data (sources are given in Section 2.2) by nonlinear estimation of exponential supply curves $C_h{}'(L) = e^{a_h + b_h L}$ for France and GB. These supply curves are shown in Fig. 4 for France (red) and GB (blue) as dashed curves. With these cost functions, 2017 loads and short term information T_h^L were simulated with (7).

Fig. 5 shows the observed trade in 2017 (under coupled markets) against the simulated latent trade T_h^L. The horizontal bands reflect the available transmission capacity, normally 2000 MW but sometimes less.[12] The latent trade exceeds the observed trade in 80% of the periods, so that censoring is required. The observed unconstrained trade matches the simulated trade perfectly, as all data points lie on the identity function. To derive this perfect alignment the loss factor was calibrated to $\tau = 0.023$. This loss factor will be used throughout the rest of the paper.

Fig. 6 shows the result of applying the trade model to the uncoupled markets of 2009, although the assumption of complete information is inappropriate for that setting. Supply curves for 2009 are presented in Fig. 4. The simulated latent trade deviates significantly from the observed trade, even when capacity constraints are not binding and censoring is unnecessary. To understand this, a model of trading between uncoupled markets is developed in the next section.

3.3. Optimal trading between uncoupled markets

When the markets were not coupled, the French market closed first, forcing traders there to anticipate British prices. As traders bid in the French market they commit to delivery, while the British market could still respond to late-arriving information, so that its price is uncertain. We treat the price difference between the markets as the (normally distributed) return on a risky investment. We assume that traders have mean-variance utility,[13] maximising a weighted combination of their expected return μ and its variance σ^2: $EU = \mu - \lambda\sigma^2/2$. A risk-averse trader with constant absolute risk aversion has $\lambda > 0$. In a two-asset portfolio consisting of 'trade' and a risk- and return-less 'opt-out' option, the expected return and its variance depend on the trading volume. The trader

[11] As unique intersections of a step curve and a monotonic line have to be identified a case distinction is required. The order of the cases can be chosen freely. Our chosen order gives a formalism that is suitable for a common econometric treatment. We could equally well reverse the second and third steps to reduce the number of computationally demanding solutions of an implicit equation.

[12] The interconnector with France has two 1000 MW bipoles, but with four pairs of cables (two pairs damaged during 2016–17) the possibility of losing 500 MW increments of capacity should be obvious.

[13] The deviation of the mean-variance representation of the portfolio with normally distributed returns can be found e.g. in Sargent, 1987, p. 154.

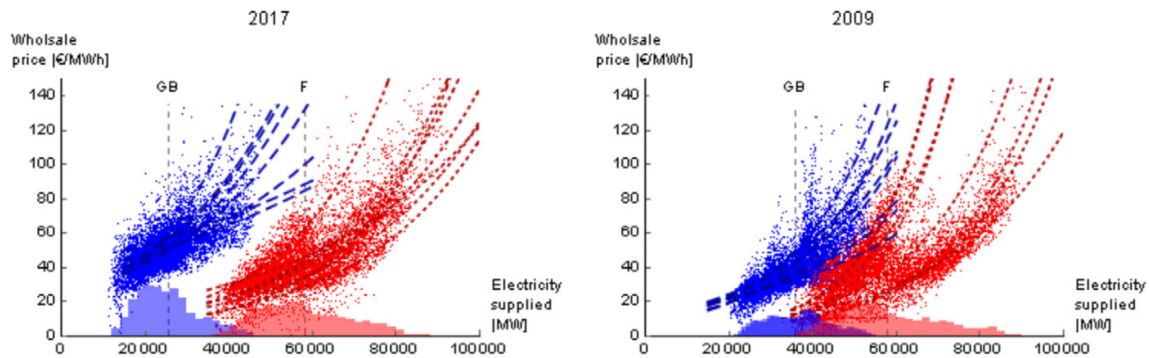

Fig. 4. Day-ahead electricity prices in 2017 (left) and 2009 (right). GB is shown in blue, and France in red. Dots represent half-hourly prices across the year, dashed lines represent the estimated half-seasonal supply curves, and pale histograms represent the load distribution (without axis labels). The average annual load is shown by vertical dashed lines.

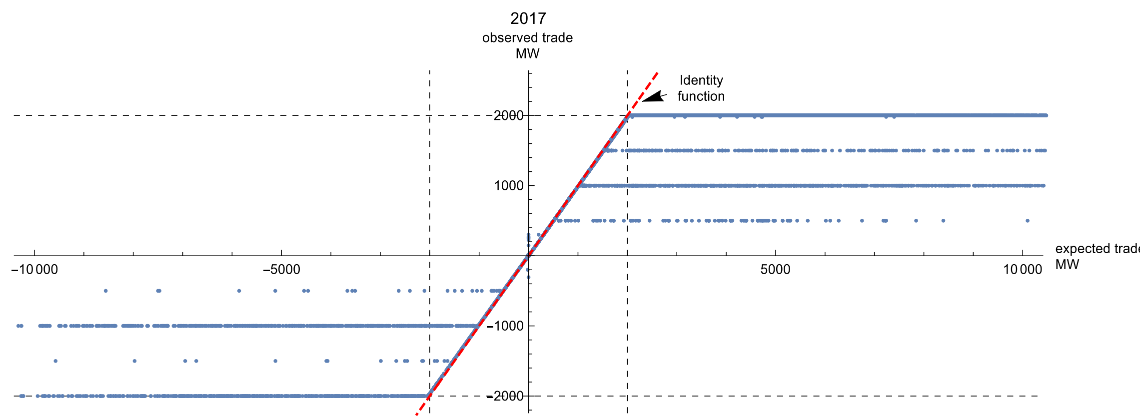

Fig. 5. Observed trade in 2017 vs simulated trade with calibrated loss factor $\tau = 0.023$.

optimally 'diversifies' as he perceives opt-out as valuable risk limitation and thereby reduces trading. To simplify the analysis there is no option to fulfil or cancel a day-ahead commitment through intraday trades.

To determine the expected return and the variance of the portfolio we need the expected British price. We assume the trader correctly anticipates short term information such that $\mathbb{E}\varepsilon_{G,h} = \varepsilon_{G,h}$, but anticipates load incorrectly as $\mathbb{E}L_{G,h} = L_{G,h} + \varepsilon_h$ with $\varepsilon_h \sim N(0,\sigma^2)$.[14] Furthermore, we assume that $C_{U,h}'$ is sufficiently linear to use certainty equivalence, so that the expected version of (6) becomes

$$\mathbb{E}p_{G,h}(T_h, \varepsilon_h) \approx C'_{G,h}(L_{G,h} + \varepsilon_h - T_h) + \varepsilon_{G,h} \tag{9}$$

The anticipation error is therefore also normally distributed and its standard deviation translates to the standard error of the value of a sold unit of electricity as $C_{G,h}''(L_{G,h})\sigma$. Optimal trade maximises the trade/opt-out portfolio with losses:

$$\max_T \mathbb{E}U_h^{Arb} = T(\mathbb{E}p_{G,h} - \varphi(T)p_{F,h}) - \frac{\lambda}{2}\left(TC''_{G,h}\sigma\right)^2 \tag{10}$$

By substituting the British price by its expectation in the optimal trading condition (4) we find optimal trading $\hat{T}$ under risk aversion $(\lambda > 0)$:

$$\hat{T}(\mathbb{E}p_{G,h}, p_{F,h}) = \begin{cases} (1-\tau)\overline{K}_h & (1-\tau)\overline{K}_h \le \theta \\ \theta & 0 \le \theta < (1-\tau)\overline{K}_h \\ 0 & (1-\tau)^{+1} < p_{G,h}/p_{F,h} < (1-\tau)^{-1} \\ \theta & -K_h < \theta \le 0 \\ -K_h & \theta \le -K_h \end{cases}$$
$$\theta = \frac{\mathbb{E}p_{G,h} - \varphi(\theta)p_{F,h}}{\lambda\left(C''_{G,h}\sigma\right)^2} \tag{11}$$

This is equivalent to Eq. (4) in the limiting cases of risk neutrality $(\lambda = 0)$ or no uncertainty $(\sigma = 0)$. If loss-adjusted prices differed in those cases, traders would want to send unlimited amounts of electricity to the higher-priced market, but would be constrained by transmission capacity. With risk-aversion and uncertainty, traders balance the expected profit from additional flows against the impact of a greater loss if the British price makes the trade unprofitable. This suppresses trade, although if the expected profit is high enough, trade will increase so that capacity limits finally bind. While risk-neutral arbitrageurs eliminate expected price differences until they become constrained, Fig. 7 shows that risk-averse traders reduce trading and price equilibration even when they are unconstrained.

The unconstrained latent equilibrium trade $T_h^{EL}(\varepsilon_h)$ can be defined in a similar way to (7) for $\lambda \ge 0$ as:

$$0 = F_E\left(T_h^{EL}, \varepsilon_h\right) := \begin{cases} pd\left(T_h^{EL}, \varepsilon_h, -1\right) & pd(0, \varepsilon_h, -1) > 0 \\ T_h^{EL} & pd(0, \varepsilon_h, +1) < 0 < pd(0, \varepsilon_h, -1) \\ pd\left(T_h^{EL}, \varepsilon_h, +1\right) & pd(0, \varepsilon_h, +1) < 0 \end{cases} \tag{12}$$

[14] This can be interpreted as an incorrect estimate of the amount of distributed variable renewable generation that will be subtracted from the overall load to give the amount that must be met in the wholesale market.

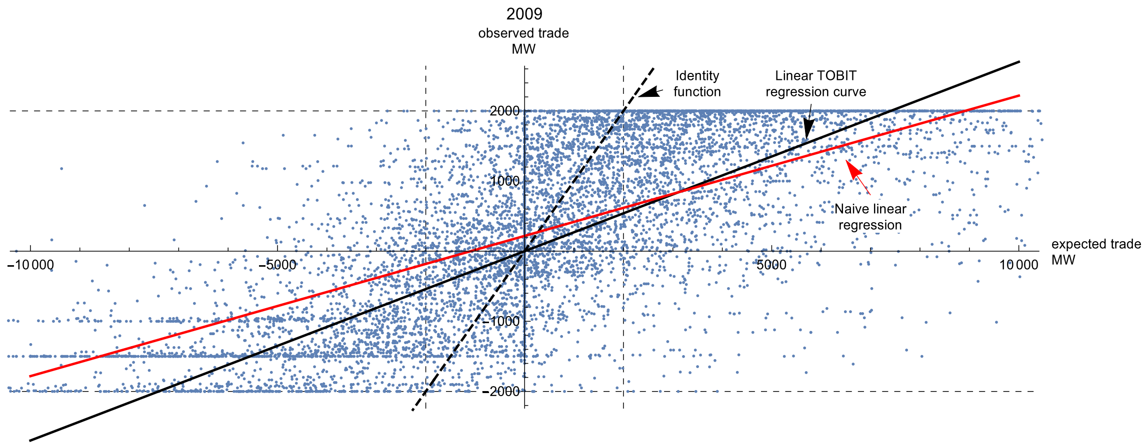

Fig. 6. 2009 latent trade with losses and observed trade data. Regression curves are going to be explained in Section 4.2.

$$pd\left(T_h^{EL}, \varepsilon_h, s\right) = \mathbb{E}p_{G,h}\left(T_h^{EL}, \varepsilon_h\right) - (1-\tau)^s p_{F,h}\left(T_h^{EL}\right) - \lambda T_h^{EL}\left(C''_{G,h}\sigma\right)^2$$

Again, due to censoring by the available transmission capacity $T_h^{EL}(\varepsilon_h)$ will not be observed directly but the censored trade equilibrium $T_h^{E*}(\varepsilon_h)$ is given by:

$$T_h^{E*}(\varepsilon_h) = \begin{cases} (1-\tau)\overline{K}_h & T_h^{EL}(\varepsilon_h) > (1-\tau)\overline{K}_h \\ T_h^{EL}(\varepsilon_h) & else \\ K_{-h} & T_h^{EL}(\varepsilon_h) < K_{-h} \end{cases} \tag{13}$$

The equilibrium trade with anticipation error, losses and capacity constraints can then be determined by Eqs. (5), (9) and (12), (13). Note that the coupled market model is a special case of the uncoupled market model (12) if $\lambda = 0$ or $\sigma = 0$.

4. Application

Our model implies that the noise clearly present in the trading in Fig. 6 is due to anticipation errors and that risk aversion should reduce trading. We now use the observed trade data in 2009 to determine the parameters σ and λ that characterise trading in an uncoupled market environment before simulating trading in uncoupled markets in 2030. However, the uncoupled market model developed so far is not well suited for the estimation of Elecxit costs as the necessary econometric quantification of the parameters is impeded by the implicit definition of the trading error. We therefore now develop an approximation of the equilibrium trading level that is better suited for an econometric estimation, allowing us to estimate the anticipation error parameters and use them to simulate Elecxit costs in 2030.

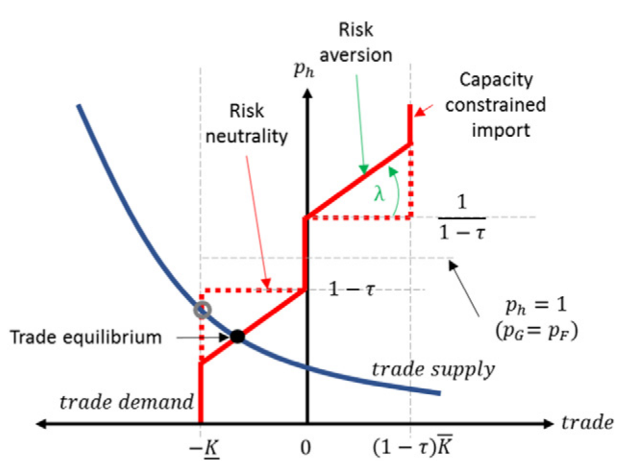

Fig. 7. The transition from coupled (perfect foresight) to uncoupled market equilibrium (risk averse trading). The transition from risk neutrality to risk aversion reduces unconstrained trading and price equilibration (p_h is a price relation).

4.1. Simplification: disentangling the anticipation error

To simulate the trading error, latent trade $T_h^{EL}(\varepsilon_h)$ can be determined by solving the implicit Eq. (12). This problem is numerically solvable for an equilibrium simulation, but for the quantification of the trade error we wish to estimate (13) as standard censored model (TOBIT). This requires the exogenous distortion to be an additive term. Unfortunately, the trading level in (12) depends nonlinearly on the anticipation error.

To solve a nonlinear equation $G(x,y) = 0$ for x, a promising strategy is to separate the solution into an easily solvable special case $y_0 = 0$: $G(x_0, 0) = 0$ and expand that solution in the neighbourhood of the special case. This uses the derivatives of G, which are also relatively easy to solve in this case by applying implicit function theorems. The solution may then be composed as $x = x_0 + G_y(x_0,0)/G_x(x_0,0)y + \ldots$ or approximated by the linear term only, which is what we need for the TOBIT analysis.

We follow this so-called perturbation approach and solve the nonlinear $F(T_h^{EL}, \varepsilon_h) = 0$ (12) for T_h^{EL} in the special case where $\varepsilon_h = 0$ and $\lambda = 0$. We start by taking the definition of the latent trade in equilibrium as an implicit function of the anticipation error $(T_h^{EL}(\varepsilon_h))$ from (12), but briefly assume $\tau = 0$ to avoid the no-trading case:

$$0 = F_E\left(T_h^{EL}, \varepsilon_h\right) = \mathbb{E}p_{G,h}\left(T_h^{EL}, \varepsilon_h\right) - p_{F,h}\left(T_h^{EL}\right) - \lambda T_h^{EL}\left(C''_{G,h}\sigma_{GB}\right)^2 \tag{14}$$

The implicit function theorem then tells us that (for small ε_h and T_h)

$$\left.\frac{dT_h^{EL}}{d\varepsilon_h}\right|_{\varepsilon_h = T_h = 0} = \frac{1}{1 + \frac{C''_{F,h}(L_{F,h})}{C''_{G,h}(L_{G,h})}} := \omega_h \tag{15}$$

We use the same approach with respect to risk aversion λ, but then take the average value of its derivative to eliminate time dependency (except for the effect of the variations in T_h^L)

$$\left.\frac{dT_h^{EL}}{d\lambda}\right|_{\varepsilon_h = \lambda = 0, T_h^{EL} = T_h^L} = -\frac{\sigma^2 T_h^L}{2}\omega_h C''_{G,h}(L_{G,h}) \approx -\frac{\sigma^2 T_h^L}{2}\frac{1}{H}\sum_{h=1}^{H}\omega_h C''_{G,h}(L_{G,h}) \tag{16}$$

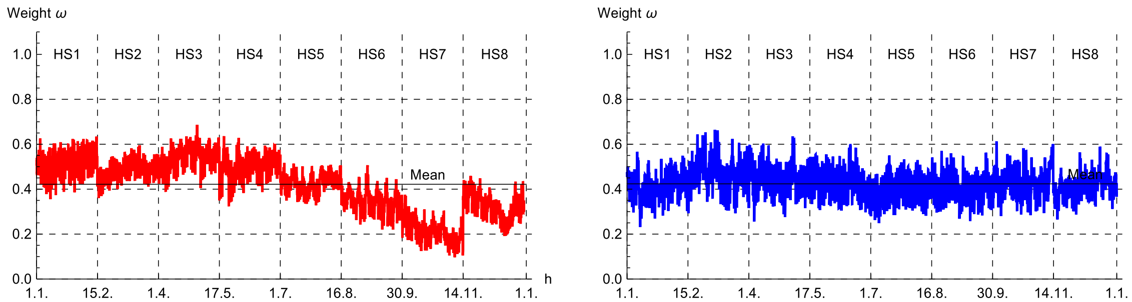

Fig. 8. Hourly amplifiers (weights) of the net load anticipation error to the trade error in 2009 (left) and 2030 (right). During each half-season (HS) supply is constant. For 2009, the calculation is based on load data and estimated supply curves presented in Fig. 8. For 2030, the calculation is based on the ENTSO-E Vision 3 scenario presented in Table 4 and the top panels of Fig. 9.

This gives rise to the desired approximation by starting with the undistorted trading level T_h^L (which is calculated with the correct value of $\tau > 0$) and adding the impact of the anticipation error $\omega_h \varepsilon_h$ and risk aversion λ:

$$T_h^{EL}(\varepsilon_h) \approx T_h^L + \frac{dT_h^{EL}}{d\lambda}\lambda + \frac{dT_h^{EL}}{d\varepsilon_h}\varepsilon_h \approx \beta T_h^L + \omega_h \varepsilon_h \tag{17}$$

with

$$\beta = 1 - \frac{\sigma^2 \lambda}{2} \frac{1}{H} \sum_{h=1}^{H} \omega_h C''_{G,h}(L_{G,h})$$

(17) is additively separated in the anticipation error and heteroscedastic with known weights ω_h. This simplification not only enables the estimation of the model in a linear TOBIT specification (as estimation equation and for jumping above capacity thresholds) but it also reveals how differently a load anticipation error transforms into a trading error depending on the difference in the slopes of generation marginal costs, driven by the generation structure and risk aversion. Furthermore it becomes apparent that risk aversion reduces trade, but only if there is indeed uncertainty (since λ is multiplied by σ^2).

Fig. 8 (left) shows that the amplifier ω_h varies strongly around an annual average of 0.42, with the lowest values seen during the autumn of 2009 and higher values in the first half of the year. The higher amplifier makes it more difficult to anticipate the optimal trade during the first half of the year than it is in the second half, even though the load anticipation variance is constant.

Optimal censored equilibrium trading T_h^{E*} then becomes

$$T_h^{E*}(\varepsilon_h) = \begin{cases} (1-\tau)\overline{K}_h & \beta T_h^L + \omega_h \varepsilon_h > (1-\tau)\overline{K}_h \\ \beta T_h^L + \omega_h \varepsilon_h & else \\ K_{-h} & \beta T_h^L + \omega_h \varepsilon_h < K_{-h} \end{cases} \tag{18}$$

Eqs. (5)–(7) could be used to determine latent trade T_h^L and (18) for the distorted censored trade with weights defined in (15).

4.2. Estimating trading distortions in 2009 (uncoupled markets)

β and the distortion parameter σ can be estimated as a heteroscedastic censored model. To do so, the supply curves estimated at the end of Section 3.2 have been used to determine the weights ω_h with (15) and in (5)–(7) to simulate latent trade T_h^L as explanatory variable in (18) for the observed censored trade $T_h^{E*}(\varepsilon_h)$. A constant α has been added to the threshold in (18) to allow testing for asymmetries between export and import. The trading error results from the weighted (ω_h) anticipation error that makes (18) heteroscedastic. Fortunately, this can be handled with the standard TOBIT model by normalising the explanatory variable, regressors and capacity limits with the weights.[15] In this way two TOBIT models for 2009 and 2017 were estimated with LIMDEP 5. The TOBIT maximum likelihood estimator relaxes the necessity to minimise the sum of squared residuals to the uncensored share of the data only, but the likelihood function is amended by the probability that the censored data indeed exceeds the censoring limits. The latter tends to put upward pressure on β.

Because trade and interconnector capacity are reported in different ways (sources are given in Section 2.2), we treated trade observations as censored if they were within 50 MW of the available capacity. The model enables us to fully account for the dynamics of the capacity already mentioned in Section 3.2. The parameter estimates are presented in Table 3.

The results for the coupled market in 2017 are completely in line with the model of Sections 3.1 and 3.2 – as already expected from Fig. 5. This can be concluded from the very small $\hat{\alpha}$ (4.57 MW, when trade can be up to 2000 MW in either direction),[16] the almost perfect predictive power of the equilibrium trade level for the observed unconstrained trade levels ($\hat{\beta} = 0.99$) and the very low standard deviation ($\hat{\sigma} = 67.1$, again in MW). The value of $\hat{\beta}$ confirms the absence of any risk and related trading reduction.

Without market coupling in 2009 the constant still had a small (insignificant) value. But the estimate of $\hat{\beta}$ suggests traders would aim to achieve only 27% of the coupled equilibrium trade level, and the anticipation error has a very large standard error ($\hat{\sigma}$) of 3035 MW. The regression curve is shown in Fig. 6. The relative risk aversion of the trader can be determined from (17) with $\hat{\beta}$ and $\hat{\sigma}$ by scaling the implicitly estimated absolute risk aversion λ with the average hourly trading revenue in 2009. The value of 2.61 is reasonable in terms of Ljungqvist & Sargent (2004, p. 426) as it lies in the interval [2,3]. It can be concluded that there is a significant risk of losses for traders and in anticipation they only take advantage of a small share of the opportunities a risk neutral trader would. We will refer to this effect as a trade crunch.

4.3. Simulation of Elecxit cost in 2030: methodology and data

We will now estimate the welfare effects of uncoupling the British electricity market from Europe. The analysis is based on the scenarios ENTSO-E Vision 2030 (ENTSO-E, 2015). We chose as base case the

15 We exploit the fact that theory predicts a specific heteroscedastic structure. In this case, the BLUE of a linear model equals the OLS estimator of the homoscedastic linear model with weighted data (Greene, 2008). Equally, the ML estimator of a TOBIT model with ex ante known heteroscedastic error structure equals the ML estimator of the homoscedastic TOBIT model with weighted data. This can easily be concluded from a comparison of the FOC's of the according likelihood functions. Each likelihood function depends on standardised probability density terms for non-censored data and standardised cumulative terms for censored data.

16 Our estimates are statistically significant, though this level of precision is quite common with 8760 hourly observations per year.

Table 3
Parameter estimates.

Generalised anticipation error model				
	Censored model 2009		Censored model 2017	
Observations	8713		8704	
AIC Information Criterion	133,087.100		19,037.300	
AIC/N	15.275		2.187	
ANOVA fit measure	0.190		11.120	
DECOMP fit measure	0.160		0.490	
Log likelihood function	−665,400,000		−95,150,000	
	Parameters	Standard error	Parameters	Standard error
$\hat{\alpha}$	-0.33^{***}	12.35	4.57^{***}	0.55
$\hat{\beta}$	0.27^{***}	0.003	0.99^{***}	0.0005
$\hat{\sigma}$	3035.60^{***}	26.64	67.10^{***}	0.79

*** 1% level.

Table 4
Data for the Entsoe Vision scenarios and our post-Brexit hybrid scenarios.

Energy scenario		Vision3		Vision1		Vision 13		Vision 13CP	
Description		Green Transition		Slow Progress		GB Slow	F Green	V13 with GB adopting EU Carbon Price	
Integration		National		National		National		As Vision 13	
Countries		GB	F	GB	F	GB	F	GB	F
Climate		Act		Delay		Delay	Act	As Vision 13	
Fuel prices		Low		High		Low	Low		
Gas	€/GJ	7.23		9.49		7.23			
Hard coal	€/GJ	2.8		3.01		2.8			
CO_2 prices	€/ton	71		17		17	71	71	71
Generation capacities									
Solar	GW	16	24	8	12	As Vision 1	As Vision 3	As Vision 13	
Wind	GW	51	37	22	22				
Hydro	GW	8	27	5	25				
Nuclear	GW	9	38	5	58				
Fossil	GW	41	22	50	14				
Load	TWh	355	481	330	447				
Residual Load	GW	28	35	34	36				

intermediate scenario “National Green Transition” (referred as Vision 3), but we also compared our results with the less ambitious transition scenario “Slow Progress” (Vision 1)[17] and two hybrid scenarios.

In particular, (Table 4), Vision 3's CO_2 prices rise to 71€/tonne, while fuel prices stay low. France halves its nuclear generation capacity (-30GW), builds up to 60 GW renewables and doubles gas (+8GW). GB abandons coal (-16GW) and has 57 GW renewables. Electricity demand increases by 60 TWh in GB compared to 2017 but stagnates in France (details in Table 4). In contrast in the “slow progress” scenario Vision 1, CO_2 prices stay at 17€/tonne with France and GB achieving only half the renewable capacity from Vision 3. Additionally, France maintains its nuclear capacity at closer to present-day levels while reduced electrification means lower load levels in both in France and GB.

As some advocates of Brexit are also climate sceptics (Bocse, 2019), it is quite possible that GB could take a different path to the EU in respect of decarbonisation (a point emphasised by an anonymous referee). We therefore model two hybrid scenarios, in which GB follows the “slow progress” Vision 1 while France continues with the “Green Transition” Vision 3. In one of these (Vision 13), GB also chooses a much lower carbon price than the EU; in the other (Vision 13CP), GB is required to adopt the EU-wide carbon price. A border carbon tax adjustment might only affect the price of traded power, but we assume the carbon price also applies to generation for domestic use.

For the simulations each step cost function of the scenario has been interpolated with an exponential function as in the previous section (capacities and marginal costs), and these are shown in Fig. 9. Load profiles and capacities for France and GB were taken from ENTSO-E. The Renewables.ninja dataset was used for the hour-by-hour capacity factors of solar PV (Pfenninger and Staffell, 2016) and wind (Staffell and Pfenninger, 2016).

We simulated generation costs for two-by-two market design and interconnector expansion scenarios for Europe and Great Britain in 2030. In the ‘Soft Elecxit’ scenario it is assumed that interconnector capacity will be expanded as planned to 10 GW and the day-ahead markets remain integrated. Effectively, this is a ‘Business as Usual’ scenario, but against a changing generation and demand background. In contrast, in the ‘Hard Elecxit’ scenario interconnector capacity will

[17] In fact, we obtained results with respect to all four Vision scenarios and found that even though they differ significantly, the impact of Elecxit was similar across Visions 1 and 2 and Visions 3 and 4. Therefore, we decided to present only Vision 1 and 3 results.

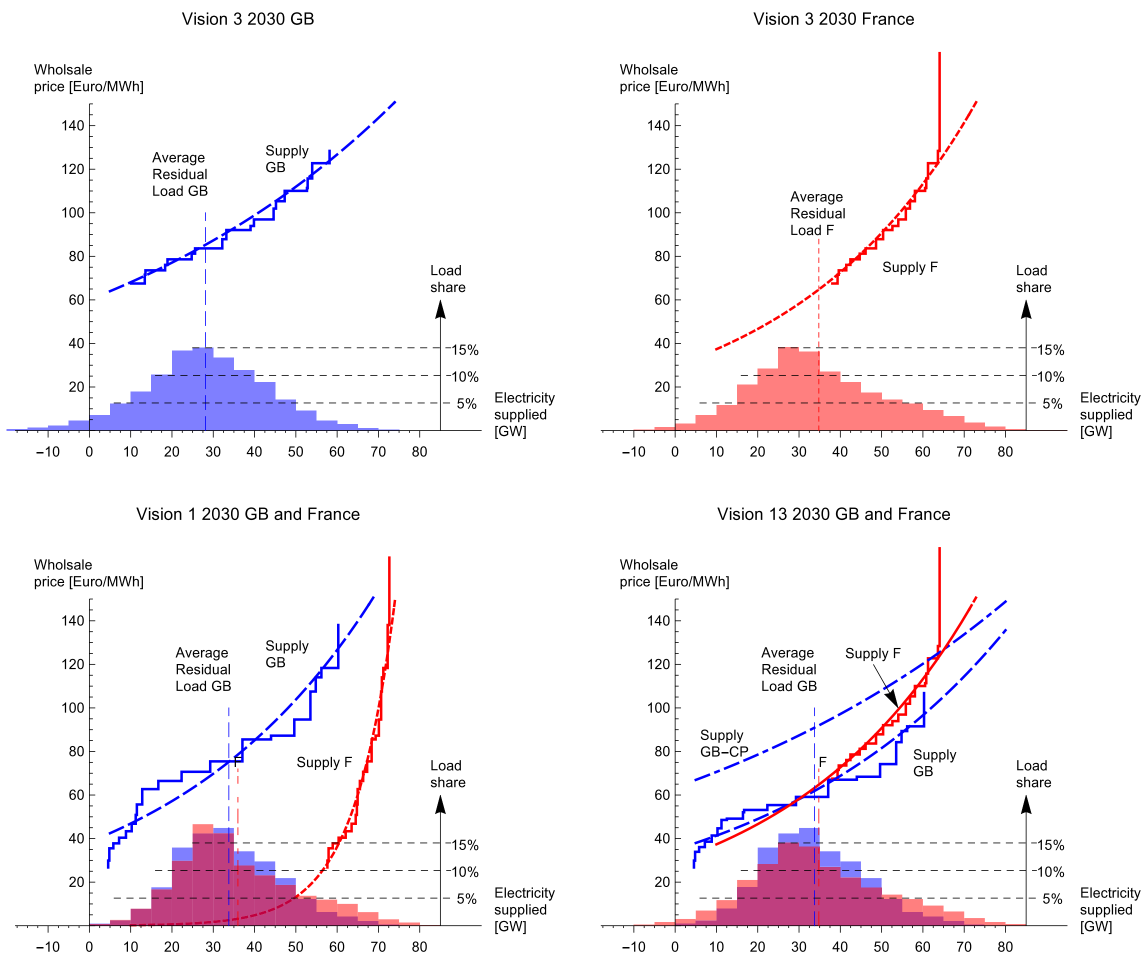

Fig. 9. The supply curve for generation and the load distribution net of intermittent renewables across our 2030 scenarios. In each panel, the full line shows the stepped-curve marginal cost of generation, and the dashed line shows the estimated supply curve. The pale histogram shows the load distribution from DESSTINEE, using the right-hand axis labels. GB is shown in blue, France in red. The top-left and top-right panels show the ENTSO-E Vision 3 scenario. The bottom-left panel shows ENTSO-E Vision 1, and the bottom-right panel shows our hybrid scenario where GB follows Vision 1 and France follows Vision 3 (with Vision 3 fuel prices for both). The dot-dashed line in that panel is the supply from GB when the EU carbon price is applied there, in Vision 13CP.

expand only slightly, to 5 GW (see introduction)[18] and the British day-ahead market will be decoupled using the Anglo-French market design of 2009. In particular, we assume that the markets close at the same times in 2030 as in 2009, which allows us to apply the estimates of the anticipation error based on 2009 data.

A standard normally distributed anticipation error was drawn for every hour of 2030. To simulate trade on uncoupled markets this basic error was scaled by twice the estimated standard deviation for 2009 (i.e. by 6000). This reflects the higher share of difficult to predict renewable generation in 2030, together with some improvements in forecasting techniques, with details in Appendix I. To convert the anticipation errors to trading errors, we use hourly weights ω_h that reflect the structure of the residual load and generation capacities in 2030. The right panel of Fig. 8 shows that the weights in 2030 on average (0.7) exceed those of 2009 (0.42).

We calculate five components of welfare. We assume that load does not react to price changes, and so the change in overall generation costs, summed across the two countries, measures the overall change in welfare (with cost increases bad for welfare, of course). The cost experienced by each country, however, consists of the cost of its own production, plus net imports valued at the average of the market prices in the two countries for the time of trade. This assumes that the interconnector rents, the trading profits from the hour-by-hour price differences times flows, are split equally between the two countries. We measure those interconnector rents directly, together with producer rents, the difference between (local) market prices and the variable cost of generation. Eqs. (19) and (20) show the relationships between these quantities[19]:

$$\underbrace{p_G(T)L_G}_{\textit{Consumer Payment G}} - \underbrace{p_G(T)(L_G-T)-C_G(L_G-T)}_{\textit{Producer Rent G}} - \underbrace{\frac{p_G(T)-p_F(T)}{2}T}_{\textit{IC Rent G}}$$
$$= \underbrace{C_G(L_G-T)}_{\textit{Production Cost G}} + \underbrace{\frac{p_F(T)+p_G(T)}{2}T}_{\textit{Price-Averaged Cost of Imports}} \tag{19}$$

$$\underbrace{p_F(T)L_F}_{\textit{Consumer Payment F}} - \underbrace{p_F(T)(L_F+T)-C_F(L_F+T)}_{\textit{Producer Rent F}} - \underbrace{\frac{p_G(T)-p_F(T)}{2}T}_{\textit{IC Rent F}}$$
$$= \underbrace{C_F(L_F+T)}_{\textit{Production Cost F}} - \underbrace{\frac{p_F(T)+p_G(T)}{2}T}_{\textit{Price-Averaged Value of Exports}} \tag{20}$$

Each line of the equations can be seen as a different presentation of the net cost of generation in that country, and hence of the negative of

[18] The reduction in transmission capacity expansion is not necessarily due to a reduced profitability of the interconnectors, but also the likelihood of higher project costs due to reduced EU investment support, and worsening intergovernmental relations in general.

[19] Transmission losses are ignored for clarity in the equations, but were taken into account in our calculations.

Table 5
Exports, market prices, CO_2 emissions and rents in Great Britain and France in a 'Hard' (dark shading) and 'Soft' Elecxit (light shading). Positive differences in rents indicate an increase in costs from 'Soft' to 'Hard' Elecxit.

Scenario: Vision 3 Green Transition		GB Elecxit Soft	GB Elecxit Hard	GB Change	France Elecxit Soft	France Elecxit Hard	France Change
Imports (gross)	TWh	53	19	-34	6	4	-2
Market price	€/MWh	81	85	4	76	71	-5
CO_2 emissions	Mio tons	59	72	13	30	27	-3
Consumer payments	€Mio	22,176	23,037	861	26,037	25,167	-870
- Generator Rent	€Mio	3,663	4,325	662	10,864	9,691	-1,173
- Interconnector Rent	€Mio	263	168	-95	263	168	-95
= Net Variable Generation Cost	€Mio	18,250	18,544	294	14,910	15,308	398
Overall Variable Generation Cost	€Mio	Soft 33,160		Hard 33,852			Change 692

welfare. The change in sign for the second term between the second lines of Eq. (19) and of Eq. (20) is because T measures imports to GB and exports from France. The next section uses this framework to assess the effects of Elecxit.

5. Results

In Section 5.1 we compare a 'Hard' and a 'Soft Elecxit' in the context of the intermediate scenario of European electricity market development "Green Transition" (Vision 3). In addition to changes in GB and French electricity markets, we examine implications for trade and the distribution of burdens between the actors in France and the UK. We then - in Section 5.2 - turn to the question of how infrastructure components and market frictions interact. Finally, in Section 5.3, we consider how sensitive these results are to the development of the European and the British electricity system, modelling the ENTSO-E Vision 1, a hybrid in which Britain backtracks on its decarbonisation plans (Vision 13) and a variation when it nevertheless adopts the EU carbon price (Vision 13CP).

5.1. 'Soft' vs. 'Hard Elecxit' in the 'intermediate' scenario

Under ENTSO-E Vision 3, GB and France have each installed over 60 GW of renewables while France has also discarded 20 GW of its nuclear generation capacity. Fig. 9 (top row) shows that GB's marginal generation costs exceed the French costs for almost all residual load levels, as France has much more nuclear capacity (with very low marginal costs) than GB in this scenario. With a similar distribution of residual loads, there is a strong incentive for British imports. With a soft Elecxit, this induces gross imports to GB of 53 TWh (Table 5, first column) while France imports 6 TWh (fourth column), making GB a net importer of electricity. Despite 10 GW of trading infrastructure, price convergence is incomplete, with prices averaging 81 €/MWh in GB and 76 €/MWh in France.

In the 'Hard Elecxit' scenario, the markets are uncoupled and transmission capacity is only 5 GW. These changes reduce electricity imports in GB to one third of the 'Soft Elecxit' level (19 TWh, the second column of Table 5) and French imports decrease from 6 to 4 TWh (the fifth column). This reduces the potential to exploit cheap hydro- and nuclear-generated French electricity and British renewables. Less trade implies less price convergence, with higher prices in GB and lower prices in France.

Those price changes have distributional consequences. Wholesale market costs for British consumers (of all kinds) rise by 4%; the increase in rents received by British generators (revenues minus variable costs) absorbs three-quarters of this. The value of the interconnectors (in terms of their trading surplus) falls by one-third. With fixed demand, our welfare measure (in the opposite direction from normal) is the variable cost of generation, equal to consumer payments less the two sets of rents. Generator costs in GB rise by almost €300 million a year, implying a welfare reduction of the same amount.

The distributional impacts in France are in the opposite direction. French consumers gain from lower bills, by almost exactly the same amount GB consumers lose (although it represents a smaller share of their bills). French generators suffer a much larger reduction in rents. Overall, French generation costs rise by almost €400 million a year. A Hard Elecxit reduces total welfare by €692 million, with 42% of the cost experienced by GB and 58% by France. There is also an increase in CO_2 emissions of 13 Mio tons in GB, only partly offset by a fall of 3 Mio tons in France.[20]

5.2. Software versus hardware: market rules and infrastructure

Do the costs of Elecxit mainly come from inefficient trading or from reduced interconnector capacity? Table 6 gives the net variable generation cost for several cases with different levels of capacity and trading inefficiency. This cost equals the actual variable cost of generation in each country, plus net imports valued (hour-by-hour) at the average of the two market prices. Our two main cases of 'Soft' (lighter) and 'Hard Elecxit' (darker) are shaded as in Table 5.

Comparing the entries along a row shows the impact of changing transmission capacity, holding trading uncertainty constant. With continued market coupling, expanding capacity from 5 GW to 10 GW would cut combined generation costs by 1.1% (the third row of the top block of figures); further expansion until there were no constraints would save an additional 0.7%. With a Hard Elecxit of anticipation errors and the resulting reduction in trading (the third block), expanding capacity from 5 GW to 10 GW would only reduce generation costs by 0.2%, and further expansion would bring practically no benefit.

Comparing the entries along a column shows how the cost of generation depends on the level of uncertainty facing would-be arbitrageurs. Comparing the top two blocks of the left-hand column, increasing uncertainty by ending market coupling across 5 GW of interconnectors raises total generation costs by 0.1%. The trade crunch increases the cost of uncoupling to 0.9% of the cost with integrated markets. The bottom block considers the case (suggested by an anonymous referee) of improved forecasting techniques reducing the errors in renewable output predictions used by traders. Demand and generation availability will remain uncertain (and have been so for long enough that we don't see why there should suddenly be great improvements in their forecasts) and so we use the same value of σ (3000 GW) that we estimated for

[20] We do not include this as a welfare cost, since generation costs include a carbon price which we assume is the correct measure of the externality involved.

Table 6
Annual Net Variable Generation Cost in GB and France in 2030. The expected market value is €37.1Bio. Percentage changes between the sum of costs due to capacity expansion in adjacent columns are shown at the bottom of each box; changes relative to the sum of costs for the top block of each column are shown at the top of each lower box. Expectations have been generated as the mean of 100 random draws of the anticipation error in each hour of our annual series. Based on Vision 3 "Green Transition".

Market design and reaction			→Implied trade specification: Share of optimal trade β (%)	→Implied trade specification: Anticipation error st. dev. σ (GW)		Interconnector capacity: 5 GW		Interconnector capacity: 10 GW		Interconnector capacity: Unlimited (Theoretical)	
Integrated markets (I)			100%	0	GB	18,398		18,250		18,204	
					F	15,140		14,910		14,724	
					Sum	33,538	-1.1%	33,160	-0.7%	32,928	
Uncoupled markets	U1	Uncertainty	100%	2 × 3000	GB	18,411	+0.1%	18,272	+0.1%	18,258	+0.2%
					F	15,152		14,930		14,744	
					Sum	33,563	-1.1%	33,202	-0.6%	33,002	
	U2	Trade crunch	27%	2 × 3000	GB	18,544	+0.9%	18,506	+1.8%	18,504	+2.5%
					F	15,308		15,264		15,262	
					Sum	33,852	-0.2%	33,770	-0.0%	33,766	
	U3	Improved forecasting	27%	1 × 3000	GB	18,497	+0.7%	18,472	+1.7%	18,471	+2.4%
					F	15,268		15,241		15,241	
					Sum	33,765	-0.2%	33,713	-0.0%	33,712	

2009. With less uncertainty but a continued trade crunch, the combined costs of generation would be 0.7% higher than with integrated markets.

The second and third columns show that the cost of uncertainty alone remain small, but that uncertainty leading to a trade crunch is expensive, and that the cost rises with the level of interconnector capacity. We infer that when transmission capacity is low, this reduces both the benefits from trades in the correct direction and the costs of trades that are based on anticipation errors; the opportunity costs from reducing trading to offset this are also small. Adding capacity increases the size of potential cost-saving trades, but our calibrated model suggests that trading errors will offset these gains. The gross saving per GW of additional capacity falls rapidly as capacity is added if markets are uncoupled, even before considering the costs of that capacity. If Britain is to give up the most effective mechanism for coordinating cross-border electricity trade, we should not invest too much in trying to increase the volume of that trade. Low interconnector capacities limit the damage that can result from anticipation errors.

5.3. Slowing the transition in GB

One might expect that efficient trading would be more valuable in a system with high shares of renewables, implying that 'Hard Elecxit' costs would be lower in a slow transition scenario like Vision 1. Table 7 actually shows that welfare losses due to trading distortions and reduced extension of transmission capacities exceed losses in the Vision 3 scenario by far: €2700 m per year. The reason is that France has an extra 20 GW of low marginal cost nuclear capacity in Vision 1 compared to Vision 3, and can export 9 TWh to GB – as long as there is a 'Soft Elecxit'. The reduction in volume (50 TWh) is somewhat greater than in Vision 3 (34 TWh), but the opportunity cost per TWh of trade foregone is much higher, due to the bigger price differences between the two countries. In that sense the estimate of welfare losses based on Vision 3 tends to be cautious.

But what if a side-effect of Brexit is that GB slows (or even abandons) decarbonisation? We model this by combining the capacity mix and carbon prices of the "Slow Progress" Vision 1 in GB with the continued "Green Transition" Vision 3 in France (Vision 13). GB's effectively-subsidised fossil generation portfolio then generates more cheaply than France (which has reduced its nuclear capacity) in for high residual loads (Fig. 9, bottom right). This promotes bidirectional trade, so a 'Soft Elecxit' (perhaps less likely in this situation) has 16 TWh imports to GB and 25 TWh imports to France, and very similar average prices (65 €/MWh in GB and 66 €/MWh in France). 'Hard Elecxit' reduces UK imports to 9 TWh and French imports to 11 TWh, but as prices (and marginal costs) generally remain close, the cost increase caused by this is small, around €200 million.

Note that in this case (only) we take account of the change in carbon emissions in GB, valued at the difference between the French price (€71, which we (here) regard as "correct") and the GB price (€17).[21] This might be seen as revenue forgone by the government from not having the correct carbon price, as well as damage done to the (global) environment. Apart from the cost of Elecxit, we are not making cross-scenario comparisons between the high-price Vision 3 and the low-price Vision 1.

As a further sensitivity analysis, we consider a case in which GB is required to adopt the higher EU carbon price, but can (and does) still choose a higher-carbon capacity mix (13CP). GB has the highest average prices of any of our scenarios, so would import more (61 TWh) under a 'Soft Elecxit' than in Vision 3. As France has less low-cost nuclear capacity than in Vision 1, GB imports are lower, and French imports higher (5 TWh) than in the pure Vision 1 scenario. With greater price differences and a bigger reduction in trade than under Vision 3, dysfunctional trade would increase 'Hard Elecxit' losses to €800 m per year compared to €700 m in Vision 3 or €200 m in Vision 13.

6. Conclusion

To calculate some of the costs of Great Britain's possible departure from the EU's internal electricity market, we start by designing a microeconomic model of the decoupled markets between Great Britain and France in 2009. Due to different market closing dates in these countries, an early commitment and the anticipation of market prices was

[21] The penalty was determined as the sum of differences between the subsidised and the not-subsidised generation costs, rather than directly from the emissions, for consistency with our other numbers.

Table 7
Cross Vision comparison of 'Soft' vs. 'Hard Elecxit' in scenarios 1, a mixture of 1 and 3 (13) and the mixture 13 with British CO_2 price dumping. Shading indicates Soft (light) and Hard (dark) Elecxit, as before.

Scenarios			Vision 1 Slow Progress			Vision 13 UK Slow F Green			Vision 13 CP Vision 13 with EU Carbon Price in both countries		
			Elecxit			Elecxit			Elecxit		
			Soft	Hard	Change	Soft	Hard	Change	Soft	Hard	Change
Great Britain	Imports (gross)	TWh	83	33	-50	16	9	-7	61	22	-39
Great Britain	Market price	€/MWh	65	72	7	65	64	-1	86	90	4
Great Britain	CO_2 emissions	Mio tons	98	121	23	140	136	-4	91	109	18
Great Britain	Consumer payments	€Mio	21,050	23,439	2,389	20,812	20,325	-487	26,921	27,901	980
Great Britain	-Generator Rent	€Mio	4,370	6,347	1,977	6,348	5,733	-615	3,943	4,716	773
Great Britain	-Interconnector Rent	€Mio	1,884	936	-948	77	45	-32	370	243	-127
Great Britain	+CO_2 revenue forgone	€Mio				8,831	8,679	-152			
Great Britain	= Net Variable Generation Cost	€Mio	14,796	16,156	1,360	23,218	23,226	8	22,608	22,942	334
France	Imports (gross)	TWh	0	1	1	25	11	-14	5	4	-1
France	Market price	€/MWh	21	13	-8	66	68	2	78	72	-6
France	CO_2 emissions	Mio tons	11	6	-5	16	23	7	33	27	-6
France	Consumer payments	€Mio	10,010	6,804	-3,206	22,644	24,199	-1,555	26,615	25,362	-1,253
France	-Generator Rent	€Mio	9,536	5,904	-3,632	7,336	8,714	1,378	11,498	9,890	-1,608
France	-Interconnector Rent	€Mio	1,884	936	-948	77	45	-32	370	243	-127
France	= Net Variable Generation Cost	€Mio	-1,410	-36	1,374	15,231	15,440	209	14,747	15,229	482
Overall Variable Generation Cost		€Mio	13,386	16,120	2,734	38,449	38,666	217	37,355	38,171	816

required to determine interconnector capacity demand. Therefore, the demand on the spot markets is not completely common knowledge at the time when trades across the interconnector must be decided, and traders must consider the risk of anticipation errors. The resulting uncertainty is added to the load as a zero mean, normally distributed disturbance, with variance that is a measure of the extent of the trade barrier. While certainty equivalence applies to expected profits, it is optimal for risk-averse traders to scale back their desired quantities to reduce the variance of their profits.

In practice, the errors mean that desired trades will be too great or too small, but the effect of these errors will be limited by the need to respect interconnector capacity constraints. If the desired trade is far greater than the available capacity, then the actual trade would be sub-optimal only if there had been a very large error in the information which it was based on. We use a TOBIT regression to estimate the level of uncertainty in 2009 between the two uncoupled markets. We find an anticipation error equivalent to load mis-forecasting with a standard deviation of 3GW and find strong evidence of risk averse trading. Thus trade 'crunches' to 27% of risk neutral trading opportunities.

We adjust these estimates for the greater uncertainty that high penetrations of wind and solar generators will induce by 2030 and apply our model to the ENTSO-E Vision 3 scenario for 2030. We estimate that a "Hard Elecxit", with little interconnector expansion and decoupled markets, would raise generation costs by €692 m per year (2% of the common market value), relative to a "Soft Elecxit" which retains business as usual, with coupled markets and interconnector capacity rising to 10 GW. Building more interconnector capacity creates little value if trading arrangements lead to substantial trading errors and strongly reduced trading. As power flows mainly from France to Britain, disrupting these flows means that British consumers would pay €861 m more, and French consumers €870 m less. British-based generators would gain, and French ones lose, but overall welfare within each country would decline, by €294 m in Britain and €398 m in France.

In sensitivity analyses, we find a scenario with similar costs from disrupting trade through Elecxit (€816 m) – one in which Britain has drastically slowed its transition towards decarbonisation but faces a border carbon tax adjustment. If Britain was able to maintain a lower carbon price than the EU, its wholesale electricity prices would be close to French levels (on the particular set of assumptions we used), so that both the gains from trade and the cost of disrupting it (€217 m) would be relatively low. If France also slowed its transition, retaining large amounts of low marginal cost nuclear plant, cross-country price differences would be much greater. In these circumstances, a Hard Elecxit would cost €2.7 billion a year.

Our estimates are based on extrapolating errors in the bilateral trading between France and Great Britain from 2009, and scaling these to represent future conditions. In practice, Great Britain already has interconnectors to four EU countries (Belgium, France, Ireland and The Netherlands). More are planned, and those in the near-term are still anticipated to go ahead regardless of the Brexit outcome (Mathieu et al., 2018). This suggests that a multilateral model might be useful to capture the interactions between these, although trading errors would all be driven by the same incorrect expectation of British net demand, and we plan to use such an approach in future work. We believe that our analysis could also be extended to cover the markets for reserve and for balancing energy – while these aspects of the Internal Energy Market are still a work in progress, National Grid (2015, Table 1) concludes that sharing reserves over interconnectors might reduce capacity needs by several GW. Without that sharing, and with less ability to dampen price spikes by increasing imports, GB might find it economic to invest in significantly more peaking capacity and electricity storage than it would otherwise require.

The aim of this paper is to delve into one aspect of the UK's potential departure from the Internal Energy Market, and while we compared four scenarios for the impact of Elecxit on interconnector trade, we have not tried to model other consequences of Brexit for the electricity sector.[22] Most forecasts suggest that Brexit will reduce the level of the

[22] These have already been the subject of much research, including Aurora Energy Research (2016), Froggatt et al. (2017), Mathieu et al. (2018), Pollitt (2017), Pollitt and Chyong (2017) and Vivid Economics (2016). Some of the impacts listed in this part of the paper are the suggestions of two anonymous referees.

UK's GDP compared to previous trends, which would affect the level of electricity demand. In the medium term, this would feed through to the amount of generation capacity, reducing the amount of investment needed. That might be fortunate if the UK outside the EU has become a less attractive destination for international investors; one vision from Brexit's advocates suggests that the UK should try to avoid this by relaxing some of its regulations in a way that would be perceived as “business friendly”. The desire to build new renewable or nuclear stations, and the ability to finance them, might be reduced. Resurgent climate scepticism could affect a wide variety of policies that would otherwise change the demand for electricity and the way in which it is supplied. Less financial support from the European Investment Bank, or EU Structural and Regional Funds, would be available; the UK has also received a disproportionately large share of EU research funding (Hepburn and Teytelboym, 2017).

The UK might find that its access to gas supplies from Europe (including Norway) is impeded; insecurity of gas supply has obvious implications for the security of electricity supply. Finally, this paper has deliberately concentrated on the electricity market in Great Britain. For nearly 12 years, the Single Electricity Market on the island of Ireland has integrated Northern Ireland with the Irish Republic, but the UK government has conceded that “there is a risk that the Single Electricity Market will be unable to continue” (BEIS, 2019). The government admits that separate markets would be less efficient – since Northern Ireland is a small system, its costs could rise significantly if it could no longer rely on its bigger neighbour. To avoid such costs, and those that we have modelled here, we can only hope that sensible policies are adopted.

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Appendix I. Variance of the anticipation error

We have extensively used the anticipation error of residual load ε_h with $\varepsilon_h \sim N(0, \sigma^2)$. We now provide a background for its variance σ^2 that enables a systematic derivation of a scenario-dependent anticipation error. Residual load in a specific country and hour h, L_h consists of the load l_h reduced by wind generation G_h^{Wind} and solar generation G_h^{Solar}

$$L_h = l_h - G_h^{Wind} - G_h^{Solar} \tag{a}$$

Each component is uncertain, and we assume has an independent normal distribution with a standard deviation proportional to its expected level in each period. We break the per-unit uncertainty into two, so that the anticipation error for load is equal to $\varepsilon_{l,\,h}\sigma_l l_h$ where $\varepsilon_{l,\,h}$ is a standard normal variable and σ_l is the constant per-unit standard deviation of the anticipation error. We use ε_{Solar} and ε_{Wind} to denote the random components while σ_s and σ_w are the constant per-unit standard deviations of solar and wind generation, respectively. Under these conditions expected residual load can thus be expressed with the residual a_c as (omitting the hour index h):

$$L_h + a_h = l_h(1+\sigma_l\varepsilon_{l,h}) - G_h^{Solar}(1+\sigma_s\varepsilon_{Solar,h}) - G_c^{Wind}(1+\sigma_w\varepsilon_{Wind,h}) \tag{b}$$

It is straightforward to show that the residual $a_h \sim N(0, l_h\sigma_l + G_h^{Wind}\sigma_w + G_h^{Solar}\sigma_s)$. In this sense we use $\sigma_h = l_h\sigma_l + G_h^{Wind}\sigma_w + G_h^{Solar}\sigma_s$. Unfortunately, σ depends on the time varying generation levels. To simplify the analysis, we approximate with a least squares estimation with $a_{wl} = \frac{\sigma_w}{\sigma_l}$ and $a_{sl} = \frac{\sigma_s}{\sigma_l}$ to get the static

$$\sigma_h \approx \sigma = \sigma_l \frac{\sum_{h=1,\dots,H}\left(l_h + G_h^{Wind}a_{wl} + G_h^{Wind}a_{sl}\right)}{H} = \sigma_l\left(\bar{l}_{UK} + a_{wl}\overline{G}_h^{Wind} + \overline{G}_h^{Solar}a_{sl}\right) \tag{c}$$

As we have already estimated the standard deviation of this anticipation error in Section 4.2 we do not need the absolute value of σ but rather the ratio between 2009 and 2030. With the parameters in Table A1, we obtain for GB:

$$\frac{\sigma^{2030}}{\sigma^{2009}} = \frac{\bar{l}^{2030} + a_{wl}\overline{W}^{2030} + a_{sl}\bar{S}^{2030}}{\bar{l}^{2009} + a_{wl}\overline{W}^{2009} + a_{sl}\bar{S}^{2009}} = 2.84 \tag{d}$$

The change in generation structure with more renewables and unchanged relative variability would nearly triple the anticipation error in 2030 compared to 2009. We assume that forecasting techniques would improve, and so (conservatively) assume in most of our predictions that the standard deviation of the anticipation error would only double in 2030 compared to 2009.

Table A1
Model parameters.

Parameter GB		2009	2030: ENTSO-E Vision 3
Average annual load (GW)	$\bar{l}$	37.1	40.5
Average annual wind generation (GW)	$\overline{W}$	1.01	18.2
Average annual solar generation (GW)	$\bar{S}$	0	1.7
Relative forecasting error wind	a_{wl}	4[a]	
Relative forecasting error solar	a_{sl}	2[b]	

[a] Hodge et al. (2012).
[b] Lew et al. (2013).

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