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Bowei Guo David Newbery Giorgio Castagneto Gissey

25 June 2019

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Keywords Carbon tax; Interconnectors; Cost-benefit analysis; M-GARCH

JEL Classification Q48; F14; D61; C13

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The Impact of Unilateral Carbon Taxes on Cross-Border Electricity Trading

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1 Introduction

Interconnectors link two electricity systems and create value by enabling the market with the higher price to import cheaper electricity from its neighbours. Market coupling makes efficient use of interconnectors by ensuring higher-price markets import until prices are equated or interconnectors constrained. Efficient systems dispatch generation units in increasing offer price order, with fossil plant typically at the margin. A carbon tax increases the cost of fossil generation and we would expect this to increase prices.

In 2011 the UK government decided to enact a gradually escalating carbon price floor for fossil generation fuels to make low-carbon generation investment commercially viable. This came into effect in April 2013 and took the form of a carbon tax (the carbon Price Support, CPS, an addition to the EU carbon price, see Figure 2) on generation fuels in Great Britain (but not Northern Ireland). This paper studies the impact of asymmetries in carbon taxes between connected countries on cross-border electricity trade. It takes Great Britain (GB) as a case study and demonstrates how the unilateral imposition of a carbon tax affects electricity prices, interconnector flows, congestion income (from the difference in price across congested interconnectors), and deadweight loss. We estimate that over 2015-2018, when the CPS stabilised at £18/t CO_2, the CPS would have raised the GB day-ahead price by an average of about €10/MWh in the absence of compensating adjustments through increased imports. The actual price differential with our neighbours fell to about €8/MWh after allowing for replacement by cheaper imports. The CPS increased GB imports by 13 TWh/yr, thereby reducing carbon tax revenue by €103 m/yr. The commercial value of interconnectors, measured by congestion income increased by €133 m/yr, half of which was transferred to foreign interconnector owners. The commercial value understates social value by ignoring infra-marginal surplus valued at around €25 m/yr, but the CPS created deadweight losses of €28 m/yr. About 18% of the increase in the GB price caused by the CPS was passed through to higher French prices and 29% in higher Dutch prices.

This paper therefore quantifies the costs and benefits of interconnector trading in the presence of an asymmetric carbon tax that distorts trade. This has implications for the design and ideally harmonisation of EU carbon taxes to improve the efficiency of electricity trading.

1.1 Literature review

The value of interconnectors and the benefit of market coupling have been widely studied (e.g. National Grid, 2014; Newbery et al., 2016; Policy Exchange, 2016; Redpoint, 2013; Pöyry, 2016). Newbery et al. (2019a) examine the efficiency and value of trading of GB interconnectors over different timescales. They find that market coupling made trading with France, the Netherlands, and the Single Electricity Market (SEM) of the island of Ireland more efficient and discuss the importance of harmonising carbon taxes across the EU. Other studies (e.g. Gugler et al., 2018; Keppler et al., 2016) focus on the integration of electricity prices across European electricity markets. They find that the increasing penetration of renewable energy counters the trend of increasing price convergence, but building more interconnectors would improve price convergence.

Previous studies concerning carbon taxes have so far focused on their impact on wholesale prices (e.g. Wild et al., 2015; Castagneto Gissey, 2014; Freitas & Da Silva, 2013; Jouvet & Solier, 2013; Kirat & Ahamada, 2011; Fell, 2010; Sijm et al., 2006), on the fuel mix and greenhouse gas emissions (e.g. Di Cosmo & Hyland, 2013; Chyong et al., 2019; Staffell, 2017), and on investment decisions within the power sector (e.g. Richstein et al., 2014; Green, 2018; Fan et al., 2010).

To the best of our knowledge, there is no *ex-post* econometric estimation of the effect of a carbon tax on cross-border electricity trading after market coupling, nor of the deadweight loss involved when applying carbon taxes asymmetrically across two electricity markets.

2 Market coupling

Starting from 4 February 2014, electricity market coupling in North Western Europe went live. Great Britain, France, and the Netherlands took part in this initiative, while on the island of Ireland the SEM was not integrated until 1 October 2018. For that reason we limit our attention to trade with our Continental neighbours, France and the Netherlands. Following market coupling, bids to buy and offers to sell are fed into a European-wide auction, which operates using EUPHEMIA (EU Pan-European Hybrid Electricity Market Integration Algorithm). Each market operator solves for its own area price at which the area's supply and demand equate. When different market prices across the interconnector occur, EUPHEMIA yields a "price-independent purchase" in the low-priced area and a "price-independent sale" in the high-priced area, corresponding to the interconnector's Net Transfer Capacity (NTC). As a result, prices in the higher-priced market decrease, and prices in the lower-priced market increase. If the prices do not converge, then the entire NTC is allocated and prices remain different in the two zones, but if the prices can be equilibrated with a smaller flow than the NTC, that flow is allocated to create a single price zone across the interconnector, *integrating* the connected markets.

2.1 Electricity trading between connected markets

Electricity is traded forward domestically on power exchanges and over-the-counter (OTC). The standard forward contract where there is a liquid spot market is the Contract-for-Difference (CfD), which specifies a quantity, M, and a strike price, s. The seller sells in the spot market at price p and receives $s-p$ from the buyer (a possibly negative amount, in which case $p-s$ is paid for the M units). The seller thus earns (and the buyer pays) $s \times M$.

Interconnector capacities are similarly sold forward in auctions for Transmission Rights held at various timescales ranging from year-ahead, to season-ahead, month-ahead and day-ahead. Once markets are coupled, the day-ahead market (DAM) becomes an implicit auction for all participating countries. The price realised in this implicit auction is then used to clear all forward contracts, with physical contracts reverting to financial rights. In addition, adjustments after the closure of the DAM are cleared in the intraday markets.[1]

If the markets are not coupled, the holder of the Physical Transmission Right (PTR) for the

[1] Article 51 of Commission Regulation (EU) 2016/1719 establishing a guideline on Forward Capacity Allocation sets out the harmonised allocation rules for long-term transmission rights, which may be either physical or financial. A more detailed example on interconnector trading can be found at https://www.ofgem.gov.uk/ofgem-publications/98321/proofofflowundermarketcoupling-europeeconomicreport-pdf.

right to import into GB will look at the day-ahead spot prices in France and GB, and exercise the option to import if the French price is below the GB price, and will abstain from nominating flows otherwise. If the importer has already bought French electricity ahead of time at a favourable price and has sold forward in GB at a price exceeding the PTR price, the importer may choose to import even if the spot price difference is unfavourable. In this case, one would observe a Flow Against Price Difference (FAPD). Given the risks involved in trading in three markets (two power exchanges and one interconnector auction) at different times, risk-averse traders may not purchase the full capacity on the interconnector auction unless its price is sufficiently below the forward price differences. Similarly, the risks of buying ahead on power exchanges before the interconnector auction clears may inhibit trade up to the interconnector's full capacity. In both cases, interconnectors will be inefficiently under-used or will flow in a wrong economic direction.

(a) Pre-coupling, 2013 (b) Post-coupling, 2017

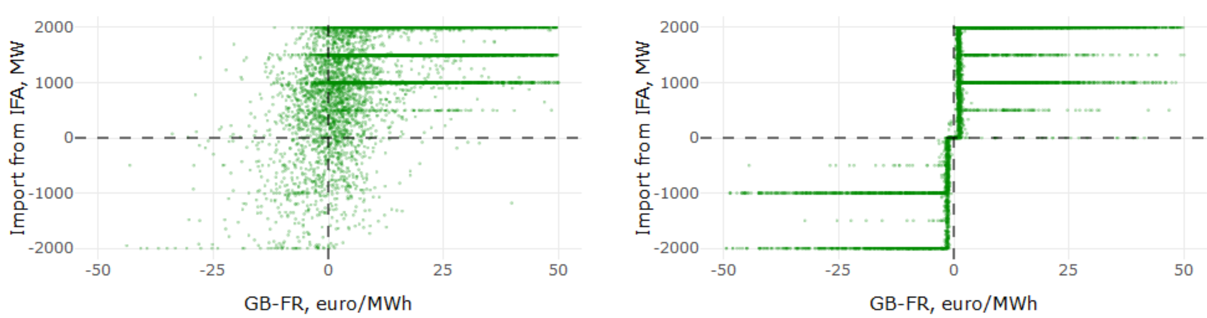

Figure 1: Day-ahead scheduled commercial exchange of IFA flows v.s. GB-FR price differentials, before and after market coupling

Source: Day-ahead scheduled commercial exchange from RTE; day-ahead GB prices from Nord Pool; day-ahead French prices from EPEX Spot.

Figure 1 plots the day-ahead scheduled commercial exchange (SCE) of net imports (exports shown negative) over the Interconnexion France Angleterre (IFA) between GB and France, before and after market coupling. There are four cables of 500 MW each for a total of 2 GW, hence the horizontal bands of observations at multiples of 500 MW are due to one or more cables under maintenance or because of network limitations. In 2013, before market coupling (Figure 1a), capacity was inefficiently used with many FAPDs, while after market coupling (Figure 1b) available capacity was efficiently used with no FAPDs.

The day-ahead scheduled commercial exchange that allocates capacity to the DAM can differ from the final recorded cross-border physical flows because market players can buy and sell intraday capacity as they receive updates on renewable generation, demand changes and plant outages. The System Operators may also intervene to balance one or both systems, although balancing markets are mostly not yet fully coupled through cross-border markets.[2,3] The actual flow will be the sum of the day-ahead, intraday and balancing flows, and any difference between the day-ahead and actual flow should corresponds to intraday nominations. Intraday flows may be hedged by buying and selling in the intraday market, or settled in the balancing market. In this paper, we focus on the day-ahead market and on the GB interconnectors that have been coupled since 2014 (i.e. IFA and BritNed).

3 The British Carbon Price Floor

The British Carbon Price Floor (CPF) was announced in the 2011 Budget and came into effect in April 2013. It was intended to make up for the failure at that time of the EU Emissions Trading System (ETS) to give adequate, credible and sufficiently durable carbon price signals. The CPF was implemented by publishing a GB[4] Carbon Price Support (CPS) that is added to the EU CO_2 Allowance (EUA) price to increase it to the projected CPF. The CPS grew from £4.94/tCO_2 in 2013 to £18/tCO_2 in 2015 (and has been frozen at £18/tCO_2 since then). The total GB carbon cost rose from £5/tCO_2 in early 2013 to nearly £40/tCO_2 by the end of 2018. Figure 2 shows the evolution of the (nominal) GB and the EU carbon costs in £/tCO_2. The two curves start diverging

[2]The SEM and GB do operate a joint balancing market.

[3]A project named Trans European Replacement Reserves Exchange (TERRE) was approved by ENTSO-E as an Implementation Project in 2016. The project aims to fulfil a European legal requirement imposed by the European Electricity Balancing Guideline. The project is expected to go live in the fourth quarter of 2019.

[4]Northern Ireland, which is part of the Single Electricity Market of the island of Ireland, is exempt to preserve an equal carbon price there.

in 2013, with the gap becoming wider in 2014 and 2015. The dashed line represents the GB carbon cost target when the CPF was announced. It was not until late 2018 that the GB carbon cost finally met the initial trajectory, thanks to the reform of the EU ETS, which introduced a *Market Stability Reserve* that removes excess EUAs and increases the European Emission Allowance (EUA) price (Newbery et al., 2019b).

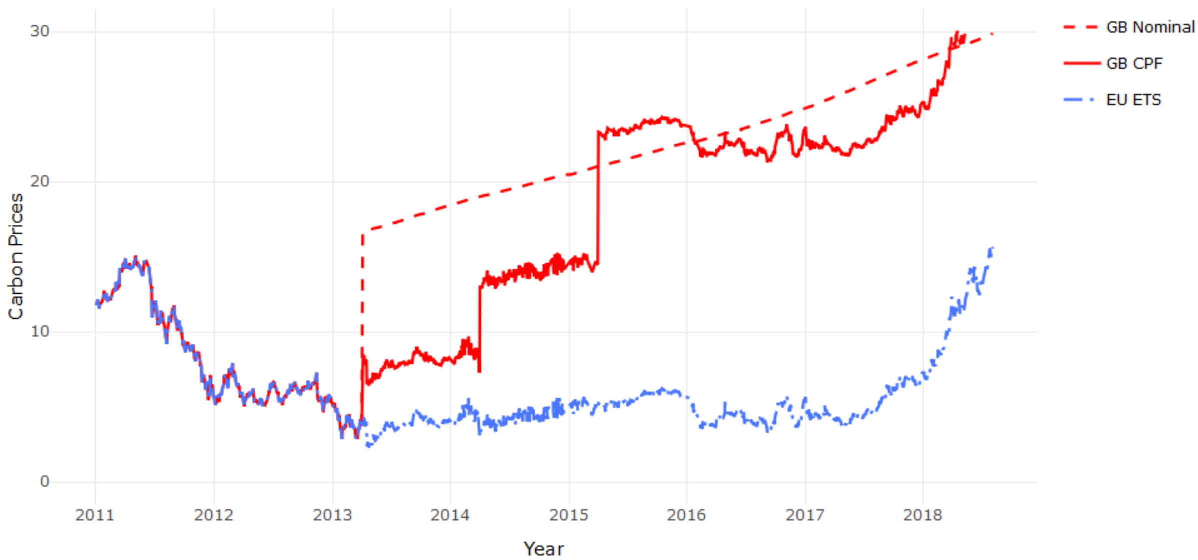

Figure 2: Evolution of the European Allowance (EUA) price and CPF, £/tCO_2

Source: Chyong, Guo and Newbery (2019).

The CPS raises the cost of fossil-fuelled electricity generation. Figure 3 plots the 28-day moving average (MA) of the day-ahead prices for GB, France (FR), and the Netherlands (NL), as well as the price differentials between the two connected markets. It also shows the variable cost (i.e. the short-run marginal cost) for Combined Cycle Gas Turbines (CCGTs) with 54.5%[5] efficiency with EUA prices included (but excluding the GB CPS) as a measure of Continental gas generation costs.

In general, while GB prices are typically higher than NL prices, the CPS widens the GB-NL price differential. FR prices are much more volatile than that in GB and NL mainly because nearly

[5] Measured at Lower Heating Value (LHV).

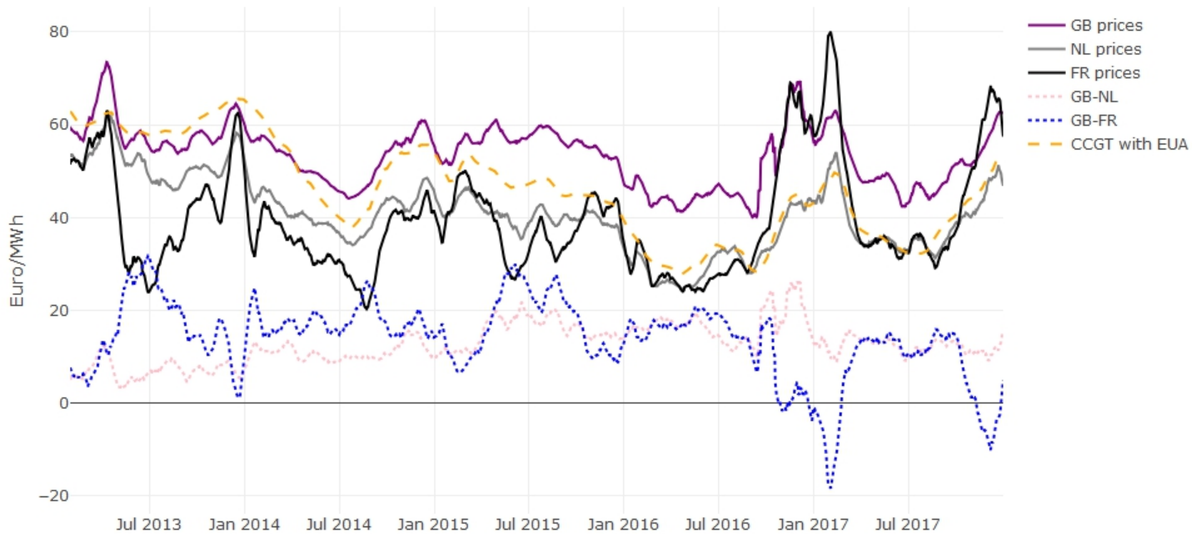

Figure 3: 28-day lagged Moving Average wholesale prices, 2013-2017

80% (in 2015)[6] of its gross electricity generation comes from nuclear power stations, making its electricity system less flexible than in GB and NL, resulting in more volatile prices. Another reason for the high volatility is that French prices are very weather-sensitive given their high domestic electrical heating load. During December 2016 and January 2017, France experienced nuclear outages,[7] which explains the negative GB−FR price differential during that period. The variable cost for CCGTs partially explains the patterns of prices for the three markets, and best fits the dynamics of the Dutch prices, where gas is likely to be the marginal fuel much of the time.

The higher GB carbon price (equivalently, the lack of an EU-wide CPS) distorts trade and could harm price convergence from market integration between the GB and Continental electricity wholesale markets.

3.1 The impact of a carbon tax

Generators offering into the DAM will likely mark-up their offers above the short-run marginal cost to recover start-up and fixed costs (and possibly further if exercising market power). Adding

[6]From Eurostat at: https://ec.europa.eu/energy/en/news/get-latest-energy-data-all-eu-countries.
[7]See https://www.ft.com/content/f86a3c6c-9c60-11e6-a6e4-8b8e77dd083a.

the CPS increases short-run marginal costs but generators may absorb some of the tax by marking up their offers by a smaller amount if the market is imperfectly competitive, depending on the shape of the residual demand curve. In the absence of any cross-border trading, the cost pass-through of the CPS would then be less than 100%. Under mark-up pricing (Newbery and Greve, 2017), however, any cost shock would also be marked up and the cost pass-through would be more than 100%.

Chyong et al. (2019) estimated the increase in marginal costs by finding the system marginal CO_2 emissions factor in each hour and multiplying it by the CPS, effectively assuming a 100% pass-through of the CPS. Our paper uses econometric methods to measure the increase in the GB wholesale price resulting from the CPS holding interconnector flows constant. This allows us to measure the domestic cost pass-through as a percentage of the system marginal cost increase. If the cost pass-through rate is less than 100% and domestic demand is insensitive to wholesale prices, the domestic impact of the CPS will be to reduce the deadweight loss of imperfect competition.

Interconnectors complicate this simple single market story. The increase in GB offer prices into the DAM will change the market clearing price and hence the congestion income (the product of DAM price differences and flows). If the CPS does not change flows (because before and after the CPS the interconnector capacity remains fully used in the same direction) there will be no additional distortion but there will be a transfer of revenue to the foreign owners of the interconnectors (both IFA and BritNed are shared 50:50 with the foreign TSOs). If flows are changed then there will be an additional deadweight loss. If demand is inelastic, the deadweight loss will be the difference in the total cost of generation with and without the CPS.

Figure 4 shows the result of imposing the CPS on GB generators when the import capacity over IFA from France (FR) is KL. If there were no interconnector, the GB price would be P_0^{GB} where the GB net supply S_0^{GB} meets demand D_0 at I. With the interconnector, the GB net supply curve meets the FR net supply curve at point H, with prices equalised (P_1^{GB}=P_1^{FR}), no congestion income and imports ML. Under the assumption of zero consumer demand elasticity (i.e. vertical demand curves), the gain in surplus created by the interconnector is entirely due to a reduction in GB generation costs, offset by a small increase in FR cost, with the net cost reduction shown as the triangle labelled "original market surplus", or HIJ. The triangle HIJ is also known as the *infra-marginal surplus* without CPS.

After the introduction of the CPS, the GB supply curve shifts upward to S_c^{GB} and the interconnector is now fully utilised with imports KL. The GB DAM (or consumer post-tax) price is P_C^{GB} but the producer price (before tax) is PP_C^{GB}. The FR price rises to P_C^{FR} and the congestion income equals KL $\times$ ($P_C^{GB} - P_C^{FR}$), or the rectangle ABCE, and the area ABN+CEJ are the infra-marginal surplus with CPS. However, while GB generation costs have fallen, FR cost has risen and the total increase in cost is the triangle HEG, which corresponds to a deadweight loss.

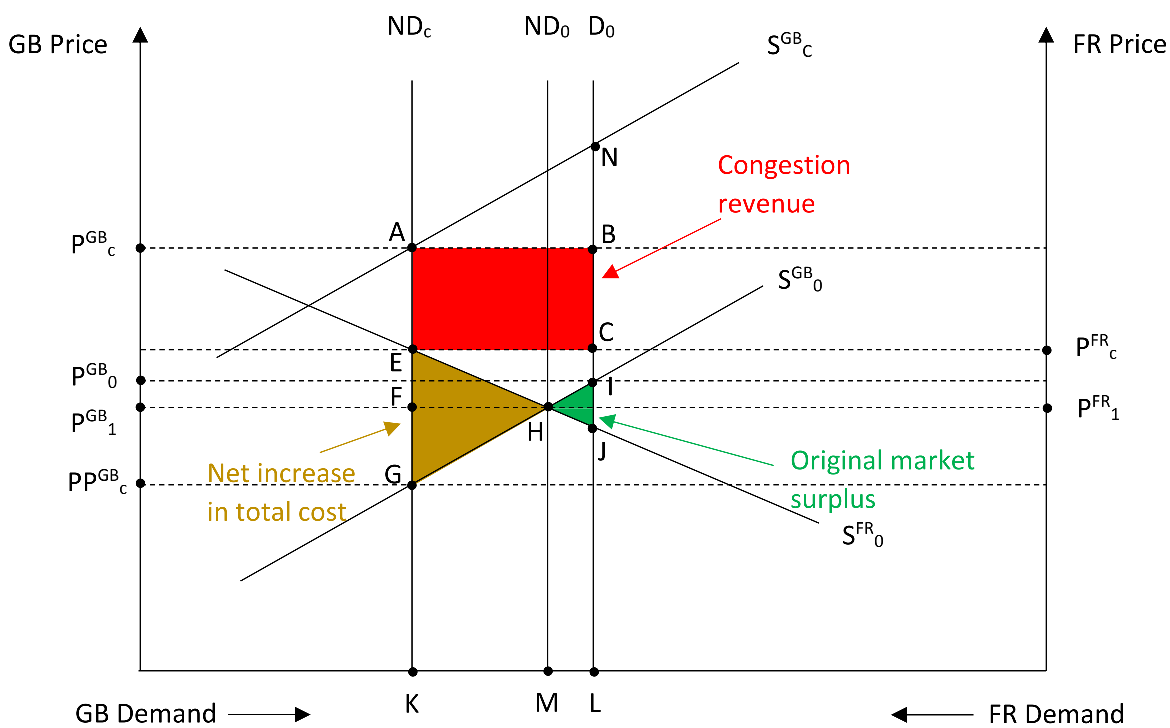

Figure 4: Impact of CPS on Imports and Surpluses, GB Imports from Partial to Full Capacity

The deadweight loss can be estimated if we can measure the GB$-$FR price differential with the carbon tax (or AE in Figure 4) and the impact of the CPS on GB prices (or AG in Figure 4). Under the assumption of (locally)linear net supply curves, given the increase in import is KM, the deadweight loss is 1/2$\times$(AG-AE)$\times$KM. The base of the triangle, AG-AE or EG is the sum of the reduction of the GB producer price ($\mathrm{P}_1^{\mathrm{GB}} - \mathrm{PP}_{\mathrm{C}}^{\mathrm{GB}}$) and the increase in the FR price due to its increase in exports ($\mathrm{P}_{\mathrm{C}}^{\mathrm{FR}} - \mathrm{P}_1^{\mathrm{FR}}$). We name this the CPS pass-through to the interconnector, and its ratio to the impact of the CPS on GB prices, or EG/AG, the cross-border CPS pass-through rate.

The typical way to estimate deadweight loss is the distortion (e.g. the tax wedge AG) times the change in output (KM), assuming consumption and production are equal (the standard closed-economy model). However, in this case GB consumption and production are not equal. Consumption remains unchanged at D_0 (because of its assumed inelasticity) while GB production falls by KM and FR production increases by the same amount, giving the total deadweight loss as the triangle HEG.

The carbon tax also leads to an increase in congestion income but half of this goes to the French TSO, the half-owner of IFA. French prices rise from $\mathrm{P}_1^{\mathrm{FR}}$ to $\mathrm{P}_{\mathrm{C}}^{\mathrm{FR}}$, increasing FR generator profits by less that the increase in consumer costs (the difference being the French share of the total deadweight loss).

Similar diagrams can be drawn for other cases (GB initially exporting, the direction of trade flows changed but not reversed, etc.), but the cost-benefit principles remain the same. Details of other cases can be found in Appendix A.3. If we ignore differences between offer prices and marginal costs and assume inelastic final consumer demand, then the benefits of the interconnectors are the total reduction in generation costs, which correspond to the fall in the importer's (higher) cost less the increase in the exporter's (lower) cost. The CPS changes this and reduces this gain as it substitutes some higher actual cost imported generation for some lower actual but higher tax-plus GB generation cost. This is with the proviso that all costs should be measured with the correct carbon prices, and we have assumed that the no-CPS equilibrium trade is the same as the correctly carbon-charged trade.

3.2 Estimating the impact of the CPS

Figure 5 plots the Price Differential Duration Schedules (PDDS) of IFA (GB *minus* FR, or PD^{IFA}) before (2013) and after (2017) market coupling. The difference between the two curves is that after market coupling, the price differentials cluster around the horizontal line at zero (Figure 5b). The reason is that there are many hours for which there is sufficient capacity to equalise GB and French prices, while it is unusual for prices to be the same for the uncoupled 2013 PDDS (Figure 5a). The line at $PD^{\text{IFA}} = 0$ is not perfectly horizontal because the prices are equated based on Mid Channel nominations and then adjusted at each end by a loss factor to give prices in each country.

(a) Pre-coupling, 2013 (b) Post-coupling, 2017

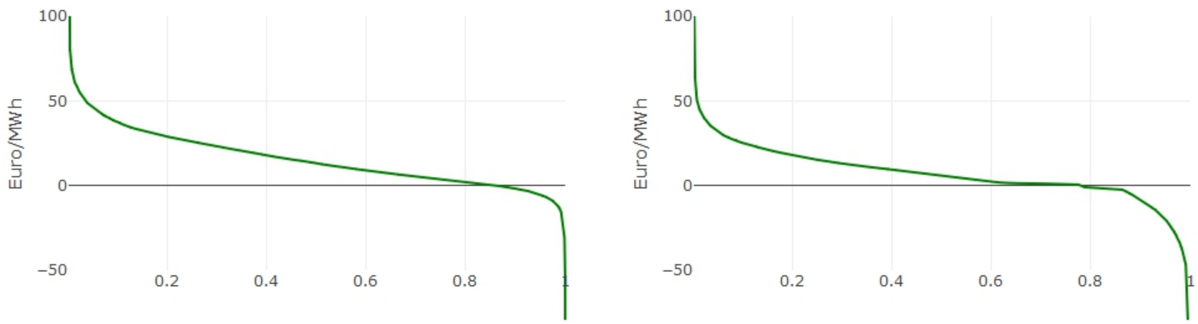

Figure 5: Price Differential Duration Schedules for IFA Price Differential (GB-FR) , 2013 v.s. 2017

Source: Day-ahead GB prices from Nord Pool; day-ahead French prices from Blomberg EPEX Spot.

Without the British CPS (while keeping the interconnector flow constant) the entire PDDS curve for 2017 (Figure 5b) would shift downwards, as illustrated in Figure 6.[8] If the market is then coupled, GB would keep exporting with full capacity at a price difference AB and keep importing with full capacity at price difference CD. The outcome is more complex at price difference BC, where with CPS, GB was either importing or exporting at less-than-full capacity. At BC, if the maximum 4 GW switch (from 2 GW to −2 GW) of the interconnector flow is sufficient to integrate the prices, the price differential for that hour would cluster at zero. If instead the 4 GW is insufficient to equalise the prices, GB would be exporting at full capacity and the price differential would fall to a negative value. For instance, suppose that the impact of flows on the price differ-

[8] To make the difference clearer, the plot assumes the CPS lowers price differentials by €30/MWh, much higher than its actual impact.

ence, PD^{IFA}, is €2/MWh/GW and that with the CPS applying, for a particular hour GB imports 0.5 GW and the GB and French markets are integrated. Now, if removing the CPS would cause the GB price to fall by €7/MWh, GB would be exporting at full capacity (2 GW) in that hour. The resulting 2.5 GW shift in the interconnector flow would, as a result of price changes, lead to PD^{IFA} falling back to €-2/MWh ($= -7 + 2.5 \times 2$).

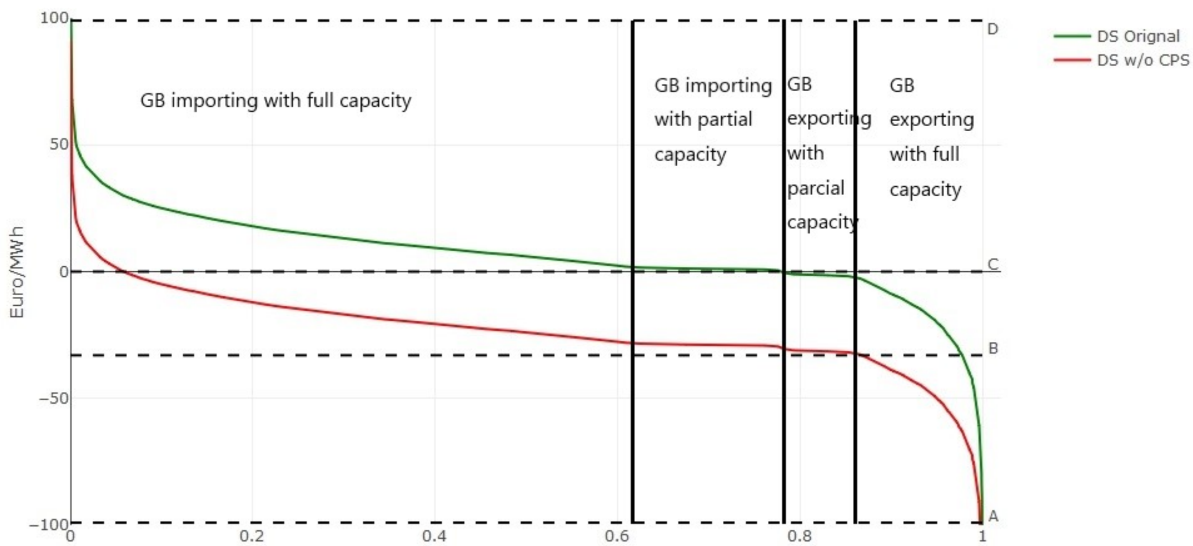

Figure 6: The Price Differential Duration Schedules with and without the CPS

The example in Figure 6 warns us against determining the impact of the CPS on interconnector flows without considering the impact of flows on the price differential. In this research, we estimate the impact of interconnector flows and the CPS on the IFA and BritNed price differentials, thereby obtaining the proportion of CPS that has been passed through to the GB day-ahead price. Using the regression results, we implement the following three-stage process. First, we estimate PDDS's without the CPS *holding flows at their original value*. Second, we re-couple the interconnector markets, with any changes in flows further influencing the price differentials. Third, using the estimated price differentials and flows without the CPS but under market coupling, we evaluate the impact of the CPS on net imports, congestion income, the carbon cost pass-through to the cross-border market, and deadweight loss.[9] We estimate the impacts on both interconnectors (IFA and

[9] Chyong et al. (2019) used the three-stage processes but in a different order: they first estimate the duration

BritNed) to estimate the improvement in efficiency from aligning carbon pricing policy.

The first challenge is that the day-ahead market is an implicit auction, which means both DAM prices and flows are determined simultaneously, resulting in simultaneous equation issues. Finding proper instrumental variables for the day-ahead flows is difficult because under market coupling, the day-ahead flows are only determined by the price differentials between day-ahead prices, the dependent variables. We address this by using the day-ahead forecast of net transfer capacity (NTC) as regression covariates instead of the day-ahead flow. NTC is only influenced by outages, maintenance or network limitations and so can be treated as exogenous. The estimated impact of NTC on the price difference allows us to estimate how flows would affect price differentials. For example, suppose 1 GW of IFA *capacity* lowers the price differential, PD^{IFA}, by €1/MWh, and the average IFA *flow* is 1.2 GW. If the average capacity for IFA is 1.5 GW (i.e. GB net imports are on average 80% of average NTC), then a 1 GW change in the *flow* would result in a €1/MWh/(80%) = €1.25/MWh change in PD^{IFA}.

The second challenge is that the econometric model only allows us to estimate the *partial* effects of the CPS on price differentials *conditional on the NTC* and the *partial* effects of the NTC on price differentials *conditional on the CPS*. Therefore using regression results to estimate the price differential after re-coupling the cross-border market (i.e. the second-stage of the three-stage process) could give invalid estimates. We deal with this by assuming that the impacts of interconnector flows on price differentials are independent of the CPS. In other words, we assume that with the CPS, a 1 GW flow would have an identical impact on the price differential as it would on the price differential without the CPS.[10]

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schedule curve without the interconnector and then estimate the impact of the CPS on the price differential. This is justified under the assumption of a 100% CO_2 pass-though, which is not conditional on the IFA transfer capacity.

[10]This assumption can be challenged by the argument that the CPS might change the merit order of fossil plants, therefore the impact of NTC/flows on price differentials can be different with and without the CPS. To test whether this is true, we implement Likelihood Ratio (LR) tests and the results suggest that the CPS has no significant impact on the impact of NTC on price differentials.

4 Econometric Models

In this section, we study the impact of interconnector flows and the British CPS on the day-ahead price differentials between the connected markets.[11] As electricity supply has to meet demand at every second, prices are highly volatile, and so are price differentials. To deal with this, we implement the Multivariate Generalised Auto-Regressive Conditional Heteroskedasticity (M-GARCH) model (Silvennoinen & Teräsvirta, 2008), which accounts for variations in both the mean and volatility of electricity price differentials. The model has been widely used to model day-ahead electricity prices (e.g. Kirat & Ahamada, 2011; Anna-Phan & Roques, 2018).

Hourly prices for the next day are all set simultaneously in the day-ahead auction. Therefore, within a day the price for any hour does not carry much information about the next hour (Keppler, 2014; Würzburg et al., 2013; Sensfuss et al., 2008), hence neither does the day-ahead price differential. As a result, instead of treating the price differentials as an hourly univariate time series, we treat them as daily multivariate time series. In order to substantially reduce the number of parameters to be estimated, we assume that during peak hours (06:00-22:00 UTC) the electricity system exhibits similar scheduling behaviour and similarly during off-peak (22:00-06:00 UTC) hours.[12] For each interconnector, there are two time series (peak and off-peak) describing the price differentials. The models we estimate are bivariate GARCH models whose *mean equation* is,

$$\boldsymbol{y}_t = \boldsymbol{\mu} + \sum_{i=1}^{m} \boldsymbol{\Phi}_i \boldsymbol{y}_{t-i} + \boldsymbol{\Gamma X}_t + \boldsymbol{\varepsilon}_t, \tag{1}$$

[11] An alternative is to study those impacts for each country separately, but that may raise the following issues: first, we use the estimation results to estimate the impact of the CPS on cross-border trading, which is only determined by price differentials between the two connected markets. Estimating the effects on each country and then combining the results is less efficient than directly estimating the impact on price differentials. Second, it ignores the price co-movements between the connected countries caused by variables that are not included in the regression (such as temperature). Third, due to the limited variation in the CPS and its modest impact abroad, directly estimating the impact of the CPS on France and the Netherlands would deliver results that are not statistically significant.

[12] Peak and off-peak hours are referenced from https://customerservices.npower.com/app/answers/detail/a_id/179/~/what-are-the-economy-7-peak-and-off-peak-periods%3F. Figure A.1 in the Appendix presents the standardised average daily load curves for the three markets during the years of studying, and the two dashed vertical lines represent borders between peak and off-peak. The estimation results change little when the time band slightly varies.

where

$$\boldsymbol{y}_t = \boldsymbol{PD}_t^{\mathrm{IC}} = \begin{pmatrix} PD_t^{\mathrm{IC,PEAK}} \\ PD_t^{\mathrm{IC,OFF}} \end{pmatrix}$$

where IC$\in$ {IFA,BN} refers to the interconnector, IFA or BritNed, and

$$PD_t^{\mathrm{IC},i} = P_t^{\mathrm{GB},i} - P_t^{\mathrm{OC},i}$$

for the other country, OC$\in$ {FR,NL}, France or the Netherlands. PD_t represents DAM price differentials, $i \in \{\mathrm{PEAK,OFF}\}$, t represents days, and P_t's are day-ahead prices. $\boldsymbol{X}_t$ is a $k \times 1$ vector of deterministic variables consisting of two types: period-specific covariates and shared covariates.

Within the day, period-specific covariates have different values in peak and off-peak periods, include day-ahead forecasts of renewable generation, day-ahead forecasts of net generation (net of imports and renewables) and day-ahead forecasts of the net transfer capacity (NTC) of IFA and BritNed. We control for nuclear generation as it can influence the day-ahead price, especially for France (see Figure 3 for the impact of French nuclear outages). All period-specific covariates can be regarded as exogenous. Renewable generation depends on weather. Once the NTC has been controlled for, net demand is exogenous as it is inelastic in the short-run (Clò et al., 2015), while day-ahead NTC depends on whether or not there are outages and is unaffected by prices. Nuclear generation runs unless there is an outage, although French nuclear power may reduce output off-peak, separating each day into peak and off-peak periods controls that endogeneity.

As GB has consistently been a net importer via IFA and BritNed, we expect the day-ahead NTC to lower the price differential. Similarly, we expect increases in GB supply (e.g. renewable and nuclear generation) and reductions in GB demand to reduce the GB price and hence the price differential, and conversely for France and the Netherlands.

The shared covariates have the same values for different periods of the same day, which includes variable costs for coal and gas plants (excluding carbon costs), the EUA price, the British CPS in Euro (using the daily exchange rate), and dummies for each season. Although some studies have found that dynamic interactions among fuel, carbon, and electricity prices may play an important role in price formation (Knittel and Roberts, 2005), we argue that fuel and carbon costs are more likely to be affected by the EU wholesale prices than by a single or pair of countries. The impact of fuels costs on the price differential would depend on the (marginal) fuel mixes in the two connected markets. Studies of IFA have shown that during 2013-2017, fossil fuel provided more than 80% of GB's marginal generation (Chyong et al., 2019; Staffell, 2017), while the marginal generation in France has heavily relied on hydro and imports, setting the price 89% of the time (Castagneto Gissey et al., 2018).

We might expect fuel costs and EUA prices to have a stronger impact on the GB DAM price than the French DAM price, while recognising that marginal imports of France come from in other fossil-fuel intensive Continental markets (e.g. Germany, Italy, and Spain). These could significantly affect the French price, making the impact of fuel costs and EUA on the GB$-$FR price differential ambiguous. Similarly, while we expect the GB$-$NL price differential to be negatively correlated with the coal price and positively correlated with the gas price because the Netherlands is more coal-intensive than GB,[13] as NL is closely integrated with other Continental European countries, these impacts can also be ambiguous.

Finally, as other EU countries have not yet followed the British CPF, we would expect the CPS to have a positive impact on price differentials for both interconnectors in both periods. The estimates for the impact of the CPS on the price differential are *conditional* on the NTC and hence holding constant interconnector flows that can affect market prices in our neighbours. The coefficients for the CPS thus estimate the undiluted (by trade) impact of the CPS on the GB DAM price. That implies that the estimated impact of the CPS on the price differentials for IFA and BritNed should be statistically insignificantly different. We can then use the result to test whether the CPS has a 100% pass-through rate in relation to the GB DAM price.

In equation (1), $\mathbf{\Phi}_1,...,\mathbf{\Phi}_m$ are 2×2 matrices of parameters capturing the spill-over effects across and within markets at period $t-i$, where $i = 1,...,m$, and $\mathbf{\Gamma}$ is an $2 \times k$ matrix with each

[13] The latest data from Eurostat shows that the fuel mix generation in the Netherlands (UK in brackets) was 35% (22%) coal and 45% (30%) gas.

element capturing the instantaneous impact of the corresponding covariates on the dependent variables. $\boldsymbol{\mu}$ and $\boldsymbol{\varepsilon}_t$ are 2×1 vectors representing the constant terms and the error terms.

The auto-regressive (AR) terms capture lagged responses to changes in market conditions. The instantaneous (or short-run, SR) impacts are captured by $\boldsymbol{\Gamma}$, while the long-run (LR) cumulative effects is $(\boldsymbol{i}' - \sum_{i=1}^{m} \boldsymbol{\Phi}_i)^{-1}\boldsymbol{\Gamma}$, where $\boldsymbol{i}$ is a 2×1 column vector of ones. The long-run effect measures the eventual change in $\boldsymbol{y}$ following a *permanent* change in $\boldsymbol{X}$. We would expect the LR effect to be greater than the SR effect as it takes time for the market to adjust to LR policy changes (such as the CPF).

In order to control for heteroskedasticity and estimate the impact of the corresponding covariates on the volatility of price differentials, we assume $\boldsymbol{\varepsilon}_t$ to be conditionally heteroskedastic:

$$\boldsymbol{\varepsilon}_t = \boldsymbol{H}_t^{1/2} \boldsymbol{\eta}_t \tag{2}$$

given the information set $\mathbf{I}_{t-1}$, where the 2×2 matrix $\boldsymbol{H}_t = [\sigma^2_{ij,t}], \forall i, j = 1, 2$, is the conditional covariance matrix of $\boldsymbol{\varepsilon}_t$. $\boldsymbol{\eta}_t$ is a normal, independent, and identical innovation vector with zero means and a covariance matrix equalling to the identity matrix, i.e. $E\boldsymbol{\eta}_t\boldsymbol{\eta}_t' = \boldsymbol{I}$.

We use the Constant Conditional Correlation (CCC)[14] GARCH(1,1) model proposed by Bollerslev (1990), where the conditional correlation matrix, $\boldsymbol{H}_t$, can be expressed as:

$$\boldsymbol{H}_t = \boldsymbol{D}_t^{1/2} \boldsymbol{R} \boldsymbol{D}_t^{1/2}, \tag{3}$$

where $\boldsymbol{R} = [\rho_{ij}]$ is a 2×2 time-invariant covariance matrix of the *standardised* residuals $\boldsymbol{D}_t^{-1/2}\boldsymbol{\varepsilon}_t$. $\boldsymbol{R}$ is positive definite with diagonal terms $\rho_{ii} = 1$. $\boldsymbol{D}_t = [d_{ij,t}]$ is a diagonal matrix consisting of conditional variances with $d_{ii,t} = \sigma^2_{ii,t}$, and $d_{ij,t} = 0$ for $i \neq j$.

The model assumes the conditional variances for the price differentials follow univariate GARCH(1,1) models and the covariance between price differentials is given by a constant-correlation

[14]The LM tests reject the null of varying conditional correlations.

coefficient multiplying the conditional standard deviation of the price differentials:

$$\sigma^2_{ii,t} = \exp(\boldsymbol{\gamma}_i \boldsymbol{z}_{i,t}) + \alpha \varepsilon^2_{i,t-1} + \beta \sigma^2_{ii,t-1}, \tag{4}$$

$$\sigma^2_{ij,t} = \rho_{ij} \sqrt{\sigma^2_{ii,t} \sigma^2_{jj,t}}, \tag{5}$$

where $\boldsymbol{z}_{i,t}$ is a $k' \times 1$ vector of deterministic variables.[15] In our case, $\boldsymbol{z}_{i,t}$ contains a constant term as well as all deterministic variables in $\boldsymbol{X}_t$ in the mean equation (1). As domestic wind might increase the volatility of both domestic and cross-border DAM prices (Annan-Phan and Roques, 2018), its impact on the volatility of the price differential is unclear as wind is correlated across neighbouring countries. We would also expect the day-ahead NTC to lower price volatility as interconnectors facilitate convergence between the connected markets. Fuel prices have an ambiguous impact on the volatility of price differentials as it depends on the fuel mix, merit order and demand between the connected markets. Lastly, we expect the CPS to raise GB day-ahead price volatility as it pushes the less flexible coal generation from baseload to mid-merit (Chyong et al., 2019), thereby raising the volatility of the GB−FR (or GB−NL) price differentials.

In equation (4), $\boldsymbol{\gamma}_i$ is a $1 \times k'$ vector of parameters capturing the instantaneous impacts of deterministic variables on the conditional variance, $\sigma^2_{ii,t}$, of $y_{i,t}$. In addition, α is the ARCH parameter capturing short-run persistence and β is the GARCH parameters capturing long-run persistence. One advantage for the M-GARCH model is that it allows for the existence of missing data, where the missing dynamic components are substituted by the unconditional expectations. The model is estimated by Maximum Likelihood Estimation (MLE). The number of lags m of the dependent variables will be determined by the Akaike Information Criterion (AIC) and the Bayesian Information Criterion (BIC).

[15] Using exponential transformations to guarantee positive volatility.

4.1 Data

Day-ahead market (DAM) price data are collected from the ENTSO-E Transparency Platform, except for GB, which is collected from the Nord Pool Market Data Platform.[16] ENTSO-E also provides the day-ahead forecast of scheduled net generation (net of imports and renewables), renewable generation (wind and solar), and net transfer capacities (NTC). For nuclear generation, due to data availability we use the *ex-post* real data as proxies for the day-head forecast. As nuclear is highly inflexible, we would expect the forecast on nuclear generation to be reasonably close to actual generation.

The daily coal and gas prices as well as the EUA price are collected from the InterContinental Exchange (theice.com). The appropriate prices are the daily prices one day ahead when offers are submitted. In order to calculate the delivered coal and gas costs into power stations, quarterly averages of the daily prices are subtracted from the BEIS quarterly "average prices of fuels purchased by the major UK power producers".[17] The daily data are then adjusted by adding this margin. All sterling prices are converted to Euros using daily exchange rates. We assume the thermal efficiency for coal-fired power plants to be 35.6% and 54.5% for CCGTs (Chyong et al., 2019). This gives the variable fossil costs for coal and gas plants in €/MWh_e without accounting for the carbon cost.

The CPS increased from £9.55/tCO_2 to £18/tCO_2 on 1 April 2015. The lack of variation can potentially result in large standard errors for the estimated coefficients. We deal with this by converting the CPS from GBP to Euro, using the daily exchange rate, which is assumed a good forecast for tomorrow's rate. This also allows us to capture the impact of policy shocks such as the Brexit referendum on cross-border electricity trading.

Table 1 gives summary statistics for all variables. Descriptive statistics of the DAM prices can be found in Appendix A.2. Outliers for price differentials are defined as values exceeding four standard deviations of the sample mean, and are removed and treated as missing data.

[16]ENTSO-E does provide the GB DAM price in sterling but Nord Pool conveniently uses the daily exchange rate to convert it from sterling to Euros.

[17]https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/790152/table_321.xlsx

Table 1: Summary Statistics, Day-ahead Markets

Variable	Unit	Abbr.	Mean	S. D.	Min.	Max.
IFA Peak diff.	€/MWh	$PD^{\text{IFA,PEAK}}$	13.55	14.82	-70.63	240.05
IFA Off-peak diff.	€/MWh	$PD^{\text{IFA,OFF}}$	11.18	10.21	-38.48	48.36
BritNed Peak diff.	€/MWh	$PD^{\text{BN,PEAK}}$	15.24	10.90	-36.41	245.52
BritNed Off-peak diff.	€/MWh	$PD^{\text{BN,OFF}}$	12.51	5.38	-6.83	33.36
Peak GB renew.	GW	$R^{\text{GB,PEAK}}$	6.63	2.86	0.95	15.47
Off-peak GB renew.	GW	$R^{\text{GB,OFF}}$	4.85	2.83	0.37	13.87
Peak FR renew.	GW	$R^{\text{FR,PEAK}}$	3.90	1.62	0.90	11.99
Off-peak FR renew.	GW	$R^{\text{FR,OFF}}$	2.54	1.52	0.54	10.90
Peak NL renew.	GW	$R^{\text{NL,PEAK}}$	1.35	0.84	0.09	5.42
Off-peak NL renew.	GW	$R^{\text{NL,OFF}}$	1.03	0.75	0.04	4.19
Peak GB net gen.	GW	$G^{\text{GB,PEAK}}$	38.60	5.62	25.44	54.10
Off-peak GB net gen.	GW	$G^{\text{GB,OFF}}$	27.26	4.42	17.63	38.84
Peak FR net gen.	GW	$G^{\text{FR,PEAK}}$	64.11	10.01	42.99	89.61
Off-peak FR net gen.	GW	$G^{\text{FR,OFF}}$	57.20	9.27	37.84	81.91
Peak NL net gen.	GW	$G^{\text{NL,PEAK}}$	15.56	3.11	7.45	25.87
Off-peak NL net gen.	GW	$G^{\text{NL,OFF}}$	14.03	2.10	8.44	21.46
Peak GB nuclear	GW	$N^{\text{GB,PEAK}}$	7.37	0.69	4.31	8.99
Off-peak GB nuclear	GW	$N^{\text{GB,OFF}}$	7.38	0.68	5.18	8.98
Peak FR nuclear	GW	$N^{\text{FR,PEAK}}$	45.04	6.56	30.03	61.27
Off-peak FR nuclear	GW	$N^{\text{FR,OFF}}$	44.07	6.46	29.89	60.54
Peak NL nuclear	GW	$N^{\text{NL,PEAK}}$	0.45	0.20	0	0.55
Off-peak NL nuclear	GW	$N^{\text{NL,OFF}}$	0.45	0.20	0	0.55
IFA peak cap.	GW	$NTC^{\text{IFA,PEAK}}$	1.77	0.38	0.33	2.00
IFA off-peak cap.	GW	$NTC^{\text{IFA,OFF}}$	1.78	0.37	0.50	2.00
BritNed peak cap.	GW	$NTC^{\text{BN,PEAK}}$	1.00	0.13	0.00	1.06
BritNed off-peak cap.	GW	$NTC^{\text{BN,OFF}}$	1.01	0.10	0.00	1.04
Coal plant var. cost	€/MWh$_e$	VC^{COAL}	29.03	5.92	17.02	43.07
Gas plant var. cost	€/MWh$_e$	VC^{CCGT}	35.32	6.90	20.52	55.15
EUA price	€/tCO$_2$	EUA	8.835	4.85	3.99	25.25
CPS	€/tCO$_2$	CPS	21.32	2.82	12.17	25.95

Table 2 shows the Augmented Dickey-Fuller (ADF) and Ljung-Box test results. The ADF tests for the existence of a unit root ($\mathbf{I}(1)$ process) and the test statistics suggest that all price differentials have no unit root. The ADF test for DAM prices are provided in Appendix A.2, which also suggests no unit root for all prices, in agreement with other research (Annan-Phan and Roque, 2018;

Table 2: ADF and Ljung-Box Tests on Price Differentails (in €/MWh), Lags=7

Variable	**Abbr.**	**ADF test**		**Ljung-Box test**	
		Statistic	P-value	Statistic	P-value
IFA Peak diff.	$PD^{\text{IFA,PEAK}}$	-6.107	0.000	164	0.000
IFA Off-peak diff.	$PD^{\text{IFA,OFF}}$	-5.249	0.000	1760	0.000
BritNed Peak diff.	$PD^{\text{BN,PEAK}}$	-9.283	0.000	167	0.000
BritNed Off-peak diff.	$PD^{\text{BN,OFF}}$	-6.608	0.000	45	0.000

Tashpulatov, 2013).[18] The Ljung-Box test uses the square of the demeaned dependent variables to test for the existence of heteroskedasticity (Harvey, 1993). The test results reject the null of homoskedastic variance, and ensures the validity of controlling for heteroskedasticity.

5 Results

Both AIC and BIC suggest the order of the autoregressive process m in the conditional mean equation (1) to be 7 for both interconnectors, equivalent to a weekly cycle, and helps to control for weekly periodicity. Likelihood Ratio (LR) tests determine whether the more complicated Dynamic Conditional Correlation (DCC) model instead of the proposed Constant Conditional Correlation (CCC) model is needed (Tse & Tsui, 2002). The test statistics for both regressions suggest using the CCC model. Estimates of the correlation coefficients, ρ_{ij} in equation (3) are within the interval of $(-1,1)$, and estimates of the conditional variance matrices, $\boldsymbol{H}_t, \forall t$ are positive definite, ensuring the validity of the M-GARCH model.

The next few subsections present the estimation results for key parameters for both IFA and BritNed. Section 5.1 presents the SR effect of deterministic variables on price differentials; section 5.2 gives the estimated LR effects; section 5.3 presents the impact on the volatility of price differentials; section 5.4 calculates, interprets and discusses the CPS pass-through to the GB DAM price. Sections 5.5 and 5.6 estimate the counterfactuals on both interconnectors without the CPS.

[18] There is also research showing the existence of a unit root on the DAM price, such as Freitas and da Silva (2013) and Fell (2010).

5.1 The short-run effects

Table 3 presents the main estimation results[19] for the mean equation (1), which gives the instantaneous (SR) impacts of deterministic variables on the price differentials. As expected, because renewable generation lowers electricity prices, GB renewable generation (R^{GB}) reduces the normally higher GB price and hence reduces the price differential. French and Dutch renewable generation (R^{FR} and R^{NL}) increase the price differential. The coefficients on renewable generation are all statistically significant. R^{FR} and R^{NL} have a higher impact on the price differential (in magnitude) than R^{GB}. The reason might be that gas sets the price over 50% of the time in GB (Castagneto Gissey et al., 2018; Chyong et al., 2019), much more than its neighbours. This means that GB has a more flexible electricity system,[20] so GB prices are less affected by the variability of renewable generation. On average, 1 GW in GB wind generation instantly reduces the GB−FR (GB−NL) price differential $PD^{\mathrm{IFA},i}$ by €0.31 (0.27)/MWh during off-peak and by €0.41 (0.57)/MWh during peak periods, while 1 GW of Continental wind generation increases in $PD^{\mathrm{IFA},i}$ ($PD^{\mathrm{BN},i}$) by €1.80 (1.86)/MWh during off-peak and by €1.86 (2.15)/MWh during peak periods.

Because GB typically imports from France and the Netherlands, additional IFA and BritNed NTC reduces price differentials for both interconnectors but creates more arbitrage revenue, though their effects are only statistically significant during peak hours. This is not surprising if both markets have convex and monotonically increasing marginal cost curves, as illustrated in Appendix Figure A.2. During off-peak periods, electricity systems are running at base load with a relatively flat marginal cost curve, so a change in net demand has little impact on prices for both markets. In general, IFA NTC has a much smaller impact on the price differential than BritNed's NTC because the French market is more than triple the size of the Dutch market (Table 1), so IFA capacity is a smaller proportion of French total load compared to BritNed's capacity share in the Netherlands. During peak periods, a 1 GW increase in the IFA NTC on average reduces $PD^{\mathrm{IFA},i}$ on that day by €1.26/MWh, while a 1 GW increase in the peak BritNed NTC on average reduces $PD^{\mathrm{BN},i}$ on that

[19] The coefficients for the rest of variables are listed in Table A.4.

[20] CCGTs are more flexible than coal-fired power plants.

Table 3: Short-run Effects: M-GARCH Mean Equations

Variable	Unit	IFA Price Diff. $PD^{\text{IFA,PEAK}}$	IFA Price Diff. $PD^{\text{IFA,OFF}}$	BritNed Price Diff. $PD^{\text{BN,PEAK}}$	BritNed Price Diff. $PD^{\text{BN,OFF}}$
R^{GB}	GW	-0.41^{***}	-0.31^{***}	-0.57^{***}	-0.27^{***}
		(0.06)	(0.05)	(0.06)	(0.05)
R^{FR} or R^{NL}	GW	1.86^{***}	1.80^{***}	2.15^{***}	1.86^{***}
		(0.10)	(0.12)	(0.20)	(0.20)
NTC	GW	-1.26^{**}	-0.19	-3.34^{*}	-0.82
		(0.45)	(0.36)	(1.40)	(1.22)
VC^{COAL}	€/MWh$_e$	-0.35^{***}	-0.20^{***}	-0.15^{***}	-0.07^{**}
		(0.04)	(0.03)	(0.03)	(0.02)
VC^{CCGT}	€/MWh$_e$	0.32^{***}	0.28^{***}	0.16^{***}	0.14^{***}
		(0.03)	(0.03)	(0.03)	(0.03)
EUA	€/tCO$_2$	-0.14^{**}	-0.10^{*}	-0.24^{***}	-0.13^{***}
		(0.05)	(0.04)	(0.04)	(0.03)
CPS	€/tCO$_2$	0.23^{***}	0.22^{***}	0.24^{***}	0.15^{***}
		(0.06)	(0.05)	(0.05)	(0.04)
No. Obs.		1412	1412	1411	1411

Standard errors in parentheses. Subscript e indicates per MWh of electricity generation
$^{***}p < 0.001$, $^{**}p < 0.01$, $^{*}p < 0.05$.

day by €3.34/MWh.

The estimates show that coal prices have a negative influence on price differentials for both interconnectors, yet the impact is higher for IFA than BritNed and for peak compared to off-peak periods. In contrast, gas prices have a positive effect on price differentials, with coefficients twice as large for IFA than BritNed, but with a negligible difference between peak and off-peak. One reason is that the CPS made coal more expensive than gas in GB, causing the share of coal to fall drastically (Chyong et al., 2019), which was not the case for the rest of the EU (at least until the end of 2017). As GB relies more heavily on gas than the Continent, coal prices have a greater impact abroad and thus negatively affect the price differential, while gas prices have a positive impact. Taking IFA as an example, a €1/MWh increase in the variable cost of coal generation is associated with a *decline* in the peak price differential by €0.35/MWh; while a €1/MWh increase in the variable cost for gas generation would *raise* the peak price differential by €0.32/MWh.

The estimated negative impact of the EUA price on price differentials is also intuitive. The CPS forces GB to become less carbon-intensive than other EU countries, hence the EUA price will have a lower impact on GB prices relative to other EU countries. A €1/tCO_2 increase in the EUA price is associated with €0.14(0.24)/MWh instant reduction in GB−FR(NL) peak price differential and with €0.10(0.13)/MWh reduction in GB−FR(NL) off-peak price differential.

The CPS raises the GB price and so should increase the price differential. Taking peak periods as examples, in the short-run, a €1/tCO_2 increase in the CPS increases the peak GB−FR price differential by €0.23/MWh, or increases the GB−NL price differential by €0.24/MWh. These impacts on price differentials are *conditional on* holding interconnector flows and Continental prices constant, and so can be regarded as two (insignificantly different) estimates of the SR impact the CPS on the GB DAM price, holding trade flows constant.

5.2 The long-run effect

Major policy changes such as the British CPF and the EU Market Stability Reserve can permanently change the carbon price, making their LR impact of greater relevance for policy analysis.

Table 4: Long-run Effects

		IFA Price Diff.			BritNed Price Diff.		
Variable	Unit	$PD^{\text{IFA,PEAK}}$	$PD^{\text{IFA,OFF}}$	$PD^{\text{IFA,AVE}}$	$PD^{\text{BN,PEAK}}$	$PD^{\text{BN,OFF}}$	$PD^{\text{BN,AVE}}$
EUA	€/tCO_2	-0.42^{*}	-0.29^{**}	-0.38^{***}	-0.63^{***}	-0.33^{***}	-0.53^{***}
		(0.14)	(0.13)	(0.12)	(0.13)	(0.08)	(0.10)
CPS	€/tCO_2	0.59^{***}	0.65^{***}	0.61^{***}	0.50^{***}	0.39^{***}	0.46^{***}
		(0.12)	(0.15)	(0.12)	(0.10)	(0.10)	(0.08)

Standard errors in parentheses.
$^{***}p < 0.001$, $^{**}p < 0.01$, $^{*}p < 0.05$.

The estimates for the LR effects of EUA and CPS, and the corresponding standard errors are listed in Table 4.[21] As expected, the LR effects of EUA and CPS are both greater than the SR effects for both interconnectors both peak and off-peak. On (weighted) average, a €1/tCO_2 permanent increase in the CPS corresponds to a €0.61/MWh (s.e.=0.12) permanent increase in the GB−FR

[21] The LR effects on other deterministic variables can be obtained from the SR results in Table 3 and A.4.

price differential, or a €0.46/MWh (s.e.=0.08) increase in the GB−NL price differential. Recall that conditional on NTC, these are also estimates of the permanent impact of CPS on the GB DAM price, and their difference is not statistically significant.

On the Brexit referendum night, the GBP/EUR exchange rate fell sharply from 1.30 to 1.17,[22] or equivalently, reduced the GB CPS by €2.34/tCO_2. In the long run, the referendum reduced the GB−FR(NL) price differential by €1.42 (1.08)/MWh.

5.3 The impact on volatilities

Given the variability of wind, evidence has been found that wind increases the volatility of domestic prices (Würzburg et al., 2013; Jensen and Skytte, 2002, and Sensfuss et al., 2008), although the impact of price differentials is less clear as wind across connected markets is strongly positively correlated in our data. The results in Table 5 suggest that off-peak renewable generation in both markets increases the volatility of price differentials while GB peak renewable generation (R^{GB}) reduces it. The positive effect is easy to explain because renewable generation (just wind as there is no off-peak solar generation) is unpredictable day-ahead. The negative effect during peak periods might be because high GB prices are less likely to occur during days with high renewable generation.[23]

Although statistically insignificant, both regressions suggest that NTC reduces the volatility of the price differential, in agreement with Annan-Phan and Roques (2018). Finally, the CPS raised the volatility of price differentials, with a statistically significant impact during peak hours, when both coal and gas plants are operating. The CPS then amplifies price variability.

5.4 The CPS pass-through to the GB day-ahead price

The CPS increases the cost of generation and raises DAM prices. The ratio between the increase in the DAM price and the increase in the system marginal cost (due to the CPS, holding interconnector

[22] See https://www.finder.com/uk/brexit-pound

[23] Evidence can be found from the data, where when the peak GB price exceeds the sample mean by more than two standard deviations, GB renewable generation is only 70% of its sample mean.

Table 5: Volatility: M-GARCH Conditional Variance Equations

		IFA Price Diff.		BritNed Price Diff.	
Variables	Unit	PEAK	OFF	PEAK	OFF
R^{GB}	GW	-0.08^{***}	0.06^{**}	-0.11^{***}	0.12^{***}
		(0.02)	(0.02)	(0.02)	(0.03)
R^{FR} or R^{NL}	GW	-0.03	0.18^{***}	0.04	0.30^{**}
		(0.03)	(0.04)	(0.08)	(0.09)
NTC	GW	-0.02	-0.13	-0.58	-0.31
		(0.13)	(0.15)	(0.36)	(0.59)
VC^{COAL}	€/MWh$_e$	0.06^{***}	-0.01	0.07^{***}	-0.05^{***}
		(0.01)	(0.01)	(0.01)	(0.01)
VC^{CCGT}	€/MWh$_e$	0.00	0.04^{**}	-0.00	0.06^{***}
		(0.01)	(0.01)	(0.01)	(0.01)
EUA	€/tCO$_2$	-0.03	0.02	-0.05^{***}	-0.00
		(0.02)	(0.02)	(0.02)	(0.02)
CPS	€/tCO$_2$	0.05^{**}	0.01	0.05^{**}	0.03
		(0.02)	(0.02)	(0.02)	(0.02)
Cond. corr.		0.48^{***}		0.29^{***}	
		(0.02)		(0.03)	

Standard errors in parentheses.
$^{***}p < 0.001$, $^{**}p < 0.01$, $^{*}p < 0.05$

flows constant) is the CPS pass-through to the GB DAM price.

Using the estimated GB marginal emission factors (MEFs) from Chyong et al. (2019) we estimate that over 2015-2018,[24] a €1/MWh increase in the CPS on average increases the system *marginal cost* of electricity by €0.374/MWh (s.e.= €0.005). Assuming the estimates of this paper and Chyong et al. (2019) are independent,[25] the SR CPS pass-through rate is 60% from IFA estimates (or 58% from BritNed estimates) with a 95% confidence interval of 35-85% (IFA) or 35-80% (BritNed).[26] In the short run, our estimates suggest that the market is not very sensitive to CPS changes due to exchange rate fluctuations.

The estimated LR CPS pass-through rate from the IFA estimate is 163% (s.e.=31%) and from the BritNed estimate is 124% (s.e.=21%). These differences are not statistically significant from

[24] Chyong et al. (2019)'s period of estimation is 2012-2017 in the Appendix, here we assume the MEF for GB in 2018 is the same as that in 2017.

[25] These papers use different datasets.

[26] See http://www.stat.cmu.edu/~hseltman/files/ratio.pdf for computing the confidence intervals.

each other nor from 100% (i.e. complete) pass-through (at the 1% significance level). This is consistent with a lagged adjustment to full pass-through and a workably competitive GB day-ahead market, although one could argue for some evidence of modest mark-up pricing and hence above 100% pass-through.

5.5 Trading over IFA without the CPS

During 2015–2018 the average peak (off-peak) IFA flow was 1,332 MW (1,206 MW) and the average peak (off-peak) NTC was 1,773 MW (1,783 MW). Given the estimated SR impacts of NTC on price differentials ($PD^{\text{IFA},i}$) in Table 3, we estimate the average instantaneous impact of IFA flows on $PD^{\text{IFA},i}$ as €-1.68/GW and €-0.29/GW for peak and off-peak, respectively.

The CPS coefficient in Table 3 shows the estimated instantaneous impact of the CPS on the price differential. Given this, we implement the three-stage processes set out in Section 3.2 – we first estimate the counterfact IFA price differential without the CPS, re-couple the market under the new price differential, and re-adjust the price differential if the interconnector flow has been changed. The actual price differential duration schedule (PDDS) curve of IFA from April 2015 to December 2018[27] as well as the estimated PDDS curve without the CPS are shown in Figure A.3.

Table 6 shows the average annual (electricity year from 1 April to 31 March) GB$-$FR price differential, GB annual net import, GB CPS tax revenue loss from trading, congestion income, infra-marginal surplus, social surplus, the CPS pass-through to the cross-border market,[28] and the deadweight loss from the carbon cost distortion. The terms are defined in Section 3.1 as well as at the bottom of the table. The difference (wherever available) between the two CPS specifications are also listed (in the columns denoted with Δ).

As expected, the CPS has increased the GB$-$FR price differential, which further raised net imports into GB. The impact of CPS on the price differential varies across years as the exchange

[27] Here the analysis starts from April 2015 (when the CPS moved to £18/tCO_2

[28] The pass-through rate in section 5.4 is the CPS pass-through to the GB DAM price, while in this and the next subsection, pass-through refers to the increase in the GB DAM price (from CPS) passes through to the cross-border trading market, due to increases in electricity imports.

Table 6: Statistical Measurements for IFA: with and without the CPS

Electricity years	**GB−FR Price Diff. (€/MWh)**			**GB Net Import (TWh)**		
	£18 CPS	£0 CPS	Δ	£18 CPS	£0 CPS	Δ
2015-2016	€18.76	€8.17	€10.58	15.51 TWh	7.87 TWh	7.64 TWh
2016-2017	€8.54	− €0.42	€8.98	8.20 TWh	−0.12 TWh	8.32 TWh
2017-2018	€10.49	€2.60	€7.89	11.33 TWh	0.56 TWh	10.77 TWh
Ave.	€12.60	€3.45	€9.15	11.68 TWh	2.77 TWh	8.91 TWh
	GB Tax Rev. Loss (m €)			**Congestion Income (m €)**		
	£18 CPS	£0 CPS	Δ	£18 CPS	£0 CPS	Δ
2015-2016	m €78.39	—	—	m €318	m €176	m €142
2016-2017	m €66.26	—	—	m €198	m €155	m €43
2017-2018	m €77.01	—	—	m €211	m €151	m €60
Ave.	m €73.89	—	—	m €242	m €161	m €81
	Infra-marginal Surplus (m €)			**Social Surplus (m €)**		
	£18 CPS	£0 CPS	Δ	£18 CPS	£0 CPS	Δ
2015-2016	m €18.36	m €15.96	m €2.40	m €336	m €192	m €144
2016-2017	m €12.52	m €12.15	m €0.37	m €211	m €167	m €44
2017-2018	m €16.81	m €15.91	m €0.90	m €228	m €167	m €61
Ave.	m €15.90	m €14.68	m €1.22	m €258	m €176	m €82
	CPS PT (€/MWh)			**Deadweight Loss (m €)**		
	£18 CPS	£0 CPS	Δ	£18 CPS	£0 CPS	Δ
2015-2016	− €1.72	—	—	m €15.67	—	—
2016-2017	− €1.87	—	—	m €16.09	—	—
2017-2018	− €2.43	—	—	m €23.07	—	—
Ave.	− €2.01	—	—	m €18.49	—	—

GB−FR Price Diff.: the average DAM price differential between GB and FR;
GB Net Import: GB's annual net import from France;
GB Tax Rev. Loss: GB's loss of carbon tax revenue due to the reduced domestic electricity production;
Congestion Income: the product of the DA spot price and scheduled commercial exchange;
Infra-marginal Surplus: the consumer surplus plus the producer surplus;
Social Surplus: the infra-marginal surplus plus the congestion income;
CPS PT: the amount of CPS passed through (PT) to the cross-border market;
Deadweight Loss: deadweight loss for society due to the carbon cost distortion.

rate fell drastically after the Brexit referendum. That has an additional impact on net imports with consequential impacts on the price differential. Perhaps unexpectedly, without the CPS, GB's net imports during 2016-2018 would be close to zero, as the DAM price between the two country would be close. This can be explained by French nuclear outages in both winters of 2016 and

2017 (see Figure 3), resulting in much higher DAM prices. During the three years, GB imported 27 TWh more electricity from France as a result of the CPS, with the loss of €222 million of carbon-tax revenue from the reduction in GB generation displaced, or €74 million/yr.

The £18/tCO_2 CPS increased congestion income by €142 million between 2015 and 2016, by €43 million between 2016 and 2017, and by €60 million between 2017 and 2018, half of which is transferred to the French TSO. While congestion income measures the private value of interconnectors, the social value would be higher as it also takes infra-marginal surplus into consideration. The estimated average infra-marginal surplus during the three years is €15.90 million with CPS or €14.68 million without, and the summation between congestion income and the infra-marginal surplus constitutes the social surplus of the interconnector.

As the CPS raised the GB DAM price and consequently, increased net imports, market re-coupling facilitates cross-border price convergence and partly offsets the initial impact of the CPS on the price differential. *With the CPS but without the market re-coupling*, the IFA price differential would have risen by €11.16 /MWh on average over 2015-2018. Re-coupling reduced that increase by €2.01 /MWh (or by 18%) on average over the three years.

Deadweight losses are incurred whenever interconnector flows change as a result of the CPS, as illustrated in Section 3.1. Assuming (locally) linear market supply curves for both GB and France, the total deadweight loss is €55.5 million for the three years, or €18.5 million/yr.

5.6 Trading via BritNed without the CPS

We could find no freely available public data providing the day-ahead scheduled commercial exchange for BritNed during 2015-2018, making it challenging to estimate cross-border trading without the CPS. However, under market coupling, the day-ahead NTC should be fully utilised if prices differ, and partially used if the markets are integrated and prices are equalised (after adjusting for the loss factor). We simulate the hourly BritNed day-ahead commercial exchange using the following algorithm:

- if both the unadjusted price differential (UDF) and adjusted price differential (APD)[29] are greater (or smaller) than zero, the NTC will be fully used for importing (or exporting);

- if the APD is zero and the UPD is positive, then the day-ahead commercial exchange would be randomly (uniformly) allocated within the interval between zero and the NTC;

- if the APD is zero and the UPD is negative, day-ahead flows would be randomly (uniformly) allocated as a negative number between *minus* NTC and zero;

- if the APD and UPD have different signs, we assume the direction of flows follows that in the previous hour, and the volume of the flow is randomly taken from the uniform distribution between zero and the NTC.

The PDDS curve for BritNed between April 2015 and December 2018 with and without the CPS are shown in Figure A.4.[30] As with IFA, Table 7 shows the CPS increases GB−NL price differentials, net imports and congestion income. Without the CPS, congestion income from BritNed would fall by €62 million in 2015-2016, by €49 million in 2016-2017, and by €44 million in 2017-2018. This amount is equally shared by the Dutch and British TSOs. The impact of the CPS on BritNed's congestion income is more stable relative to IFA as the GB−NL price differential is less volatile (see Figure 3). In addition to the private value (i.e. the congestion income), the social value created by the BritNed is estimated to be around €10 m/yr higher.

More imports result in a loss of carbon-tax revenue of €87 million over the three years, or €29 million/yr. On average, the increased imports reduced the price differential by €2.62/MWh, or 29% of the initial impact of the CPS on GB prices (holding interconnector flows unchanged). This is higher than IFA because the Dutch DAM price is more sensitive to interconnector flows compared to the French DAM price, due to its smaller market size. The deadweight loss from CPS averages €9.41 million/yr.

[29] Adjusted by the BritNed loss factor of 3%, see https://www.britned.com/about-us/operations/.

[30] During 2015–2018 the average peak (off-peak) BritNed flow was 867 MW (798 MW) and the average peak (off-peak) NTC was 1001 MW (1006 MW). Given the estimated SR impacts of NTC on price differentials ($PD^{\mathrm{BN},i}$) in Table 3, we estimate the average instantaneous impact of BritNed flows on $PD^{\mathrm{BN},i}$ as €−3.79/GW and €−0.91/GW for peak and off-peak, respectively.

Table 7: Statistical Measurements for BritNed: with and without the CPS

Electricity years	GB−NL Price Diff. (€/MWh)			GB Net Import (TWh)		
	£18 CPS	£0 CPS	Δ	£18 CPS	£0 CPS	Δ
2015-2016	€17.00	€9.35	€7.64	8.27 TWh	5.04 TWh	3.23 TWh
2016-2017	€15.78	€9.60	€6.19	7.85 TWh	4.26 TWh	3.39 TWh
2017-2018	€12.82	€7.36	€5.46	7.71 TWh	3.69 TWh	4.02 TWh
Ave.	€15.20	€8.77	€6.43	7.94 TWh	4.33 TWh	3.61 TWh
	GB Tax Rev. Loss (TWh)			**Congestion Income (m €)**		
	£18 CPS	£0 CPS	Δ	£18 CPS	£0 CPS	Δ
2015-2016	€31.71	—	—	€148	€86	€62
2016-2017	€27.61	—	—	€137	€88	€49
2017-2018	€27.34	—	—	€113	€69	€44
Ave.	€28.89	—	—	€133	€81	€52
	Infra-marginal Surplus (m €)			**Social Surplus (m €)**		
	£18 CPS	£0 CPS	Δ	£18 CPS	£0 CPS	Δ
2015-2016	m €11.64	m €9.25	m €2.39	m €160	m €96	m €64
2016-2017	m €11.20	m €9.25	m €1.95	m €149	m €98	m €51
2017-2018	m €10.76	m €8.54	m €2.22	m €124	m €78	m €46
Ave.	m €11.20	m €9.01	m €2.19	m €144	m €90	m €54
	CPS PT* (€/MWh)			**Deadweight Loss (m €)**		
	£18 CPS	£0 CPS	Δ	£18 CPS	£0 CPS	Δ
2015-2016	– €2.34	—	—	€8.32	—	—
2016-2017	– €2.60	—	—	€9.38	—	—
2017-2018	– €2.90	—	—	€10.53	—	—
Ave.	– €2.62	—	—	€9.41	—	—

6 Conclusions and policy implications

Market coupling ensures the efficient use of interconnectors so that the higher-priced market always imports electricity from the lower-priced market. A unilateral carbon tax distorts trade if it alters interconnector flows, resulting in deadweight losses. In all cases, carbon taxes transfer revenue abroad at a cost to the domestic economy.

This paper investigated the impact of such a carbon tax on cross-border trading of electricity, both theoretically and empirically. We provide a social cost-benefit framework showing how the carbon tax impacts cross-border trade. Empirically, taking the British Carbon Price Floor (CPF) with its Carbon Price Support (CPS, a tax) as a case study, we estimate the influence of the CPS and interconnector capacity on the price differentials between GB and its Continental neighbours France, through IFA, and the Netherlands, through BritNed. Our results isolated the price differential that would have arisen without the CPS, allowing an estimate of interconnector flows without the CPS. Comparing observed flows and prices (with the CPS) with this counterfactual (without the CPS), provides a quantitative estimate of the impact of the British CPS on net imports, congestion income, infra-marginal surplus, deadweight loss, and the amount of British carbon tax passed through to the cross-border market over both interconnectors.

Our estimates do not reject the null hypothesis that in the long run the CPS has been fully passed through to the GB day-ahead price. During electricity years 2015-2018, the CPS increased the GB DAM price by roughly €10/MWh in the absence of trade adjustments. The actual price differential with our neighbours fell to about €8/MWh allowing for displacement by cheaper imports. The CPS increased imports by 8.9 TWh/yr from France and by 3.6 TWh/yr from the Netherlands, thereby reducing carbon tax revenue by €74 m/yr from IFA and by €39 m/yr from BritNed. Congestion income for IFA was increased by €81 million/yr and for BritNed's by €52 million/yr, and the infra-marginal surplus from cross-border trading is around €15/m/yr for IFA AND €10 m/yr for BritNed. The summation of congestion income and infra-marginal surplus constitutes the social value of the interconnector. We estimated the deadweight loss due to the CPS at €18.5 million/yr for IFA and €9.4 million/yr for BritNed. On average, about 18% of the increase in the GB day-ahead price from the CPS has been passed through in higher French prices and 29% in higher Dutch prices.

The results confirm that the British CPS raised the GB spot price, reduced the convergence of cross-border electricity prices and increased GB imports of electricity. Second, the increase in congestion income (mostly) comes from GB electricity consumers but is equally allocated to both Transmission System Operators as owners of the interconnectors. This increased congestion income could over-incentivise further investment in additional interconnectors, at least to carbon-intensive markets lacking such carbon taxes. Third, as a non-negligible proportion of the GB DAM price increase caused by the CPS was passed over the interconnectors, both French and

Dutch day-ahead prices have been slightly increased. That raised their producer surplus but increased consumer electricity costs. Fourth, the objective of the British CPS is to reduce British CO_2 emissions and incentivise low-carbon investment, but this is partly subverted by increased imports of more carbon-intensive electricity. (The same argument could previously be made that reductions in GB emissions are offset by increased emissions elsewhere, but this has been largely addressed by the Market Stability Reserve.) Finally, asymmetric carbon pricing in two connected countries incur deadweight losses, resulting in less efficient cross-border trading.

Despite the CPS distorting cross-border electricity trading, it has significantly reduced GB's greenhouse gas emissions from electricity generation. On 21 April 2017, GB power generation achieved the first ever coal-free day. When the UK introduced the CPF, the hope was that other EU countries would follow suit to correct the failures of the Emissions Trading System, at least for the electricity sector. The case for such an EU-wide carbon price floor is further strengthened by the desirability of correcting trade distortions.

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A Appendices

A.1 Figure Appendix

Figure A.1 shows the average daily load curves for GB, France, and the Netherlands during 2015-2018, at Coordinated Universal Time (UTC). To facilitate comparison, we standardise each curve by dividing its hourly loads by its maximum load.

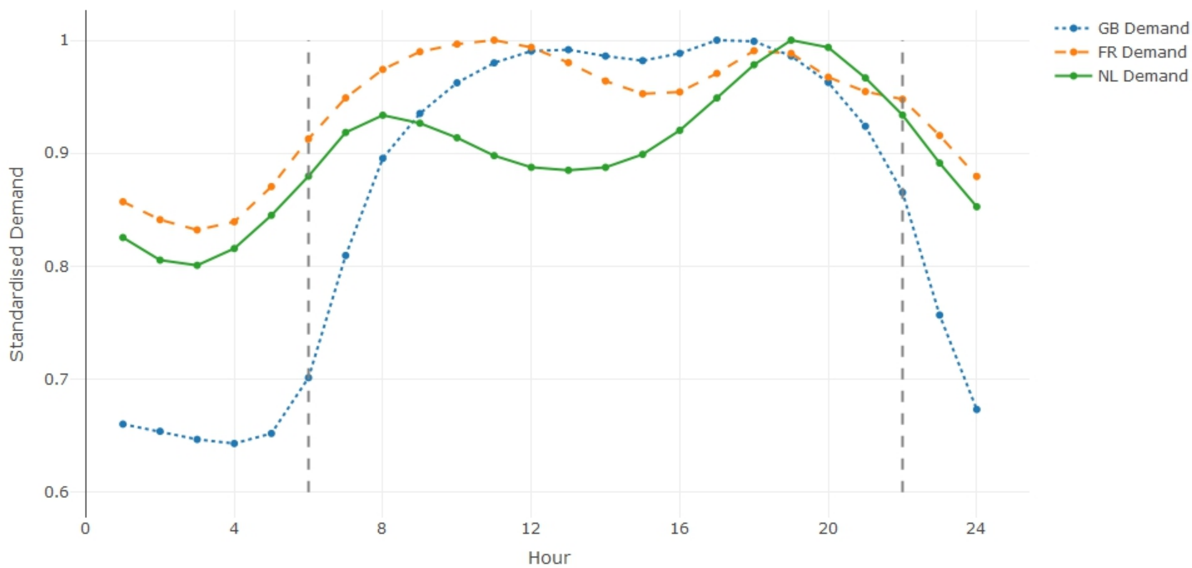

Figure A.1: Standardised Daily Average Load Curves, 2015-2018, UTC

Figure A.2 plots an electricity market with a convex supply curve, where during off-peak periods during which excess exports shift demand from ND_0^{OFF} to ND_1^{OFF}, the spot price decreases by only a small amount.

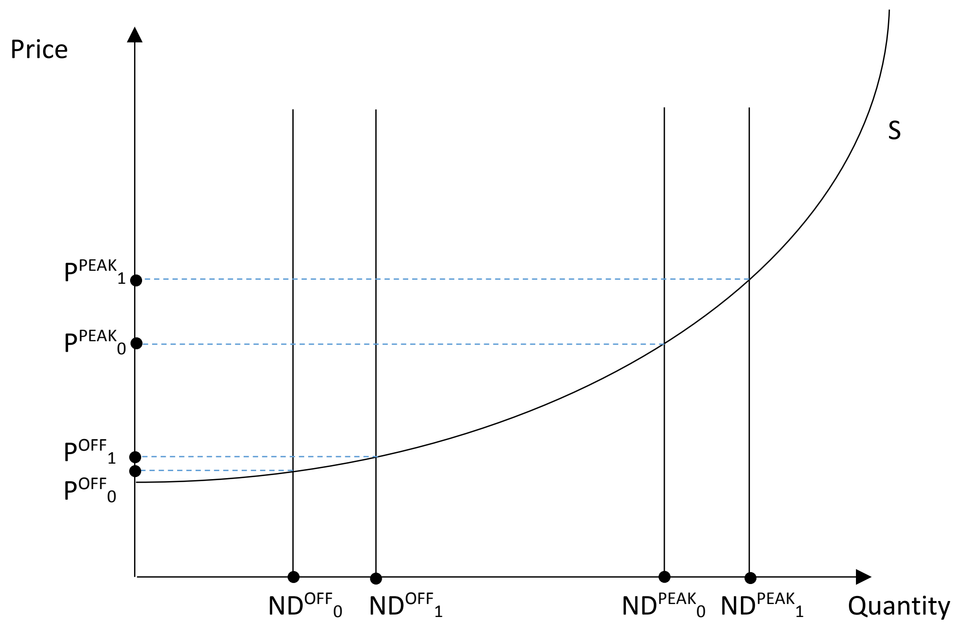

Figure A.2: A Market with a Convex Supply Curve

The price differential duration schedule (PDDS) curves for IFA and BritNed, with and without the CPS, are shown in Figures A.3 and A.4. These use unadjusted price differentials,[31] so the IFA price differentials cluster *around* instead of *at* zero.

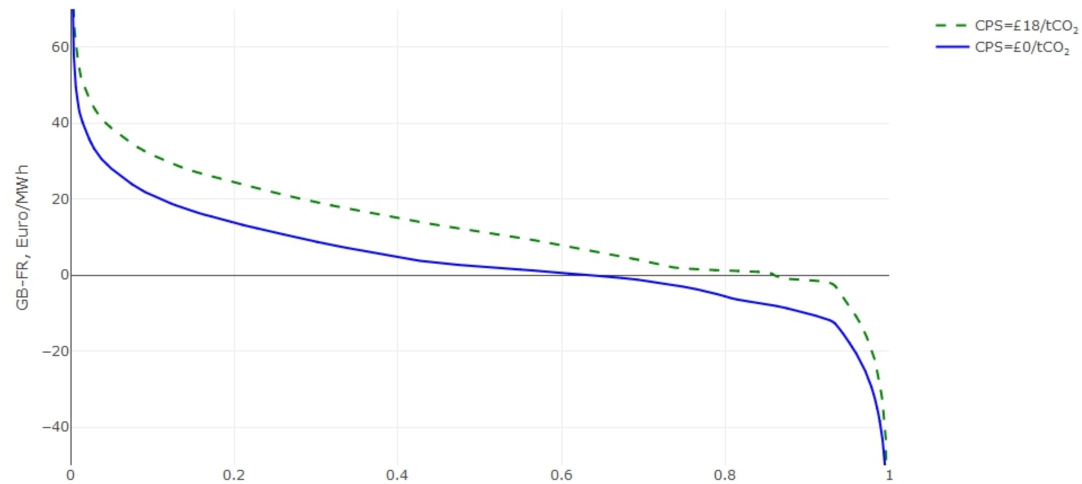

Figure A.3: The DS Curves for IFA with Different CPS, April 2015 - December 2018

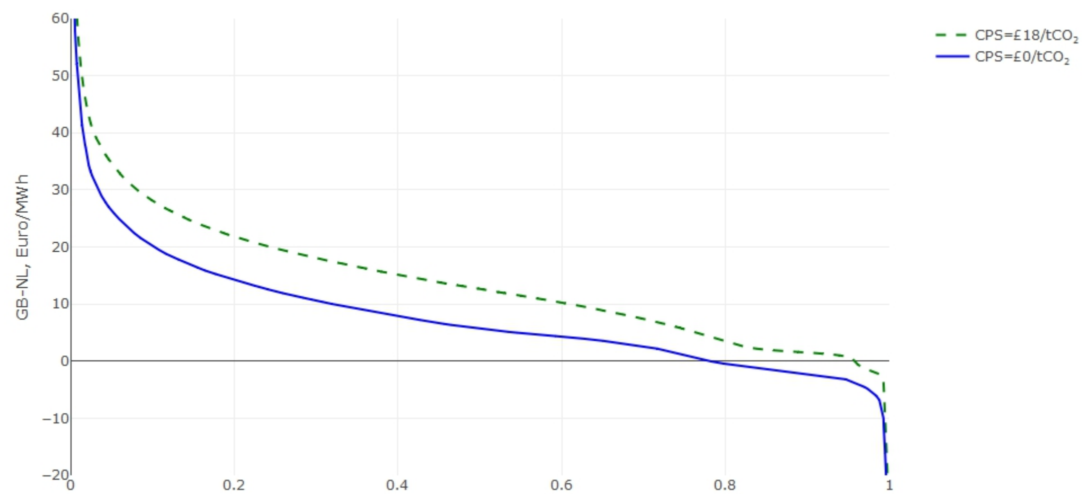

Figure A.4: The DS Curves for BritNed with Different CPS, April 2015 - December 2018

[31] Unadjusted for losses. See https://www.nationalgrideso.com/sites/eso/files/documents/Border_Specific_Annex_IFA_Interconnector_0.pdf and http://ifa1interconnector.com/media/1022/ifa-loss-factor.pdf

A.2 Table Appendix

Table A.1 presents summary statistics for day-ahead market (DAM) prices for GB, France, and the Netherlands. The hourly data is aggregated by periods (peak and off-peak) of the day, and the statistics presented are for the daily averaged peak and off-peak prices for each market.

Table A.1: Summary Statistics, Day-ahead Markets, 2015-2018

Variable	Unit	Abbr.	Mean	Std. Dev.	Min.	Max.
Peak GB DAM price	€/MWh	$P^{\mathrm{GB,PEAK}}$	60.06	13.16	35.75	284.01
Off-peak GB DAM price	€/MWh	$P^{\mathrm{GB,OFF}}$	45.96	9.39	17.3	79.48
Peak FR DAM price	€/MWh	$P^{\mathrm{FR,PEAK}}$	46.53	18.35	6.98	165.42
Off-peak FR DAM price	€/MWh	$P^{\mathrm{FR,OFF}}$	34.73	12.64	-5.02	89.61
Peak NL DAM price	€/MWh	$P^{\mathrm{FR,PEAK}}$	44.84	12.48	16.87	108.74
Off-peak NL DAM price	€/MWh	$P^{\mathrm{FR,OFF}}$	33.40	9.20	7.97	64.44

Table A.2 shows the Augmented Dickey-Fuller tests on the DAM prices, all tests reject the null of the existence of a root unit.

Table A.2: ADF Tests for DAM Prices (in €/MWh), Lags=7

Variable	ADF test	
	Statistic	P-value
Peak GB DAM price	-6.039	0.000
Off-peak GB DAM price	-3.434	0.047
Peak FR DAM price	-5.055	0.000
Off-peak FR DAM price	-5.335	0.000
Peak NL DAM price	-4.133	0.006
Off-peak NL DAM price	-3.714	0.022

Table A.4 shows the M-GARCH results for other covariates included in the regression. We also test whether the impact of NTC on the price differential is independent with the CPS. We assume the coefficients for NTC are (linear and quadratic) functions of the CPS, and likelihood ratio (LR) tests do not reject the null hypothesis that the impact is independent with the CPS.

Table A.3: M-GARCH Results: Mean Equations (Cont'd)

	IFA Price Diff.		BritNed Price Diff.	
	$PD^{\text{IFA,PEAK}}$	$PD^{\text{IFA,OFF}}$	$PD^{\text{BN,PEAK}}$	$PD^{\text{BN,OFF}}$
L.$PD^{\text{IFA,PEAK}}$ or L.$PD^{\text{BN,PEAK}}$	0.26***	0.04*	0.20***	0.02
	(0.02)	(0.02)	(0.03)	(0.01)
L2.$PD^{\text{IFA,PEAK}}$ or L2.$PD^{\text{BN,PEAK}}$	−0.03	−0.05*	0.03	−0.02
	(0.03)	(0.02)	(0.03)	(0.01)
L3.$PD^{\text{IFA,PEAK}}$ or L3.$PD^{\text{BN,PEAK}}$	−0.02	−0.03	0.05*	0.02
	(0.03)	(0.02)	(0.02)	(0.01)
L4.$PD^{\text{IFA,PEAK}}$ or L4.$PD^{\text{BN,PEAK}}$	0.00	−0.02	0.01	−0.01
	(0.02)	(0.02)	(0.02)	(0.01)
L5.$PD^{\text{IFA,PEAK}}$ or L5.$PD^{\text{BN,PEAK}}$	−0.00	−0.00	0.02	−0.01
	(0.02)	(0.02)	(0.02)	(0.01)
L6.$PD^{\text{IFA,PEAK}}$ or L6.$PD^{\text{BN,PEAK}}$	0.03	0.01	0.08***	−0.01
	(0.03)	(0.02)	0.02	(0.01)
L7.$PD^{\text{IFA,PEAK}}$ or L7.$PD^{\text{BN,PEAK}}$	0.12***	0.01	0.11***	0.01
	(0.02)	(0.02)	0.02	(0.01)
L.$PD^{\text{IFA,OFF}}$ or L.$PD^{\text{BN,OFF}}$	0.01	0.39***	0.07*	0.37***
	(0.03)	(0.03)	(0.03)	(0.03)
L2.$PD^{\text{IFA,OFF}}$ or L2.$PD^{\text{BN,OFF}}$	0.04	−0.02*	−0.05	0.00
	(0.04)	(0.03)	(0.03)	(0.03)
L3.$PD^{\text{IFA,OFF}}$ or L3.$PD^{\text{BN,OFF}}$	0.09**	0.12***	0.02	0.05
	(0.03)	(0.03)	(0.03)	(0.03)
L4.$PD^{\text{IFA,OFF}}$ or L4.$PD^{\text{BN,OFF}}$	0.02	0.02	0.02	0.02
	(0.03)	(0.03)	(0.03)	(0.02)
L5.$PD^{\text{IFA,OFF}}$ or L5.$PD^{\text{BN,OFF}}$	0.04	0.03	−0.03	0.03
	(0.03)	(0.03)	(0.03)	(0.03)
L6.$PD^{\text{IFA,OFF}}$ or L6.$PD^{\text{BN,OFF}}$	0.04	0.08**	−0.09**	0.07**
	(0.03)	(0.03)	0.03	(0.03)
L7.$PD^{\text{IFA,OFF}}$ or L7.$PD^{\text{BN,OFF}}$	−0.03	0.05*	0.06	0.07**
	(0.03)	(0.02)	0.03	(0.03)
D^{GB}	−0.57***	−0.42***	−0.26***	−0.07
	(0.06)	(0.06)	(0.04)	(0.04)
D^{FR} or D^{NL}	−0.53***	−0.44***	−0.11	−0.12*
	(0.05)	(0.05)	(0.07)	(0.05)
N^{GB}	−0.26	−0.13	−0.51*	−0.28
	(0.24)	(0.19)	(0.23)	(0.15)
N^{FR} or N^{NL}	0.70***	0.41***	1.88*	1.28**
	(0.07)	(0.06)	(0.80)	(0.46)
SPRING	1.05	−0.37	−1.71***	−0.79*
	(0.63)	(0.51)	(0.41)	(0.32)
SUMMER	−2.46***	−3.26***	−3.23***	−1.23**
	(0.71)	(0.60)	(0.45)	(0.41)
FALL	−3.59***	−4.25**	−1.84***	−0.99**
	(0.68)	(0.53)	(0.45)	(0.33)

*** $p < 0.001$, ** $p < 0.01$, * $p < 0.05$

Table A.4: M-GARCH Results: Conditional Variance Equations (Cont'd)

	IFA Price Diff.		BritNed Price Diff.	
	$PD^{\text{IFA,PEAK}}$	$PD^{\text{IFA,OFF}}$	$PD^{\text{BN,PEAK}}$	$PD^{\text{BN,OFF}}$
D^{GB}	0.07^{***}	0.03	0.07^{***}	-0.06^{**}
	(0.02)	(0.03)	(0.01)	(0.02)
D^{FR} or D^{NL}	0.01	-0.06^{**}	-0.03	-0.12^{***}
	(0.02)	(0.02)	(0.03)	(0.03)
N^{GB}	-0.08^{***}	0.08	-0.12	0.16
	(0.02)	(0.08)	(0.08)	(0.09)
N^{FR} or N^{NL}	-0.03	-0.00	-1.11^{***}	0.42
	(0.03)	(0.03)	(0.25)	(0.28)
SPRING	-0.05	-0.06	0.45^{**}	-0.00
	(0.24)	(0.18)	(0.16)	(0.16)
SUMMER	-0.41	-0.73^{***}	0.45^{***}	-0.36
	(0.28)	(0.24)	(0.16)	(0.21)
FALL	-0.29	-0.79^{***}	0.67^{***}	0.04
	(0.24)	(0.20)	(0.13)	(0.16)

$^{***}p < 0.001$, $^{**}p < 0.01$, $^{*}p < 0.05$

A.3 Cost-benefit analysis, an extension

Figure A.5 shows another case when the CPS alters the interconnector flow, where GB was initially exporting at partial capacity, LM, and the prices of the two markets are integrated at P_1^{GB}=P_1^{FR}. Without the interconnector the GB price would be P_0^{GB}. The market surplus is again the producer (GB) surplus plus the consumer (FR) surplus, HIJ, and there is zero congestion income.

The CPS shifts the GB supply curve upward from S_0^{GB} to $\text{S}_\text{C}^{\text{GB}}$, and that switches GB from being a net exporter to a net importer. Similar to the case in Figure 4, the deadweight loss is the triangle HEG, which can be calculated as the half of the product of the swing of the interconnector flow, KL, and its impact on the cross-border price differential, ($\text{P}_\text{C}^{\text{FR}}-\text{P}_1^{\text{FR}}$)+($\text{P}_1^{\text{GB}}-\text{PP}_\text{C}^{\text{GB}}$), or EG. Hence EG/AG is the CPS pass-through rate.

The loss in carbon tax revenue is again AG$\times$KL, and the congestion income under the CPS is ABCE, half of which goes to the French TSO.

The final case where the CPS changes interconnector flows is shown as Figure A.6. Without the CPS, GB was initially exporting at full capacity, KL, and the market clearing price was P_1^{GB} for

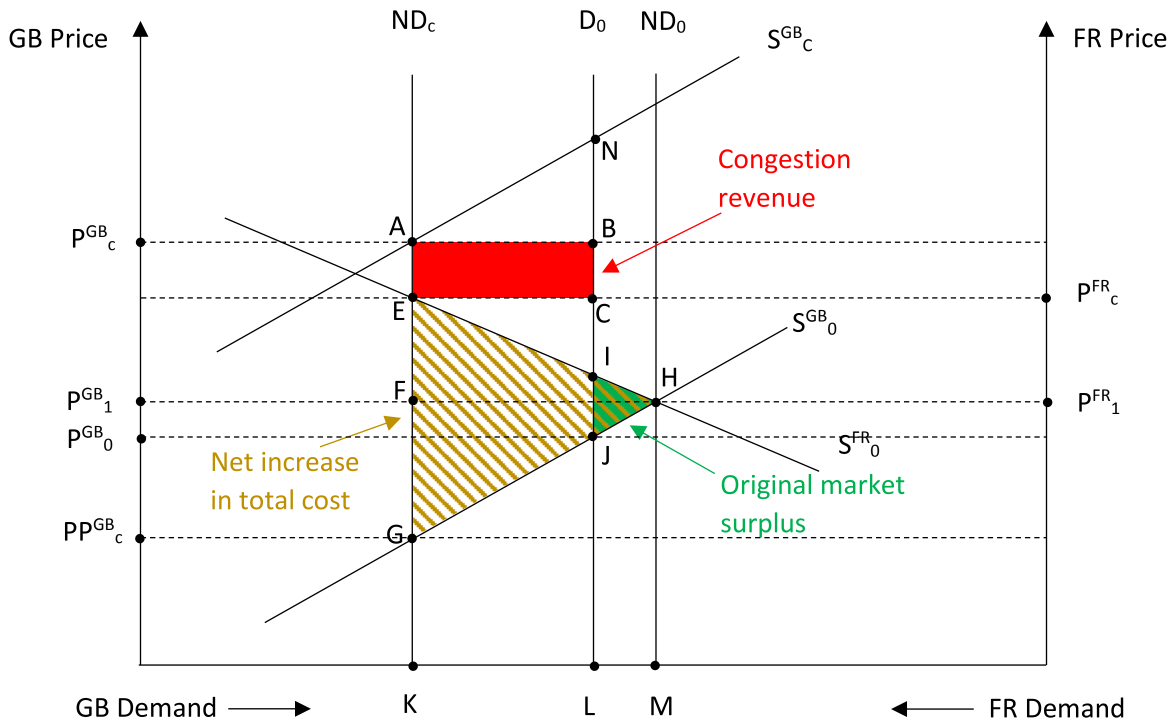

Figure A.5: Impact of CPS on Imports and Surpluses, GB from Exporting to Importing

GB and P_1^{FR} for France. The market surplus is the green area HFG+ABC and the congestion income is the red rectangular BCFH.

The CPS shifts the GB supply curve from S_0^{GB} to S_C^{GB}. While still exporting, the amount GB exported has been reduced to KM. Consequently, the deadweight loss caused by the CPS is the shaded area BIQ+HJR, or half of the change in the interconnector flow, ML, multiplied by the change in the price differential (due to the change in the interconnector flow), IQ+JR. The CPS PT ratio in this case is (IQ+JR)/EG.

The loss in carbon tax revenue is ML$\times$EG, and there is no congestion income under the CPS.

A.4 Trading in the intraday and balancing market

This section intends to prove the credibility of our simulated BritNed day-ahead scheduled commercial exchange data, by comparing with the real-life data from the IFA day-ahead scheduled commercial exchange from RTE.

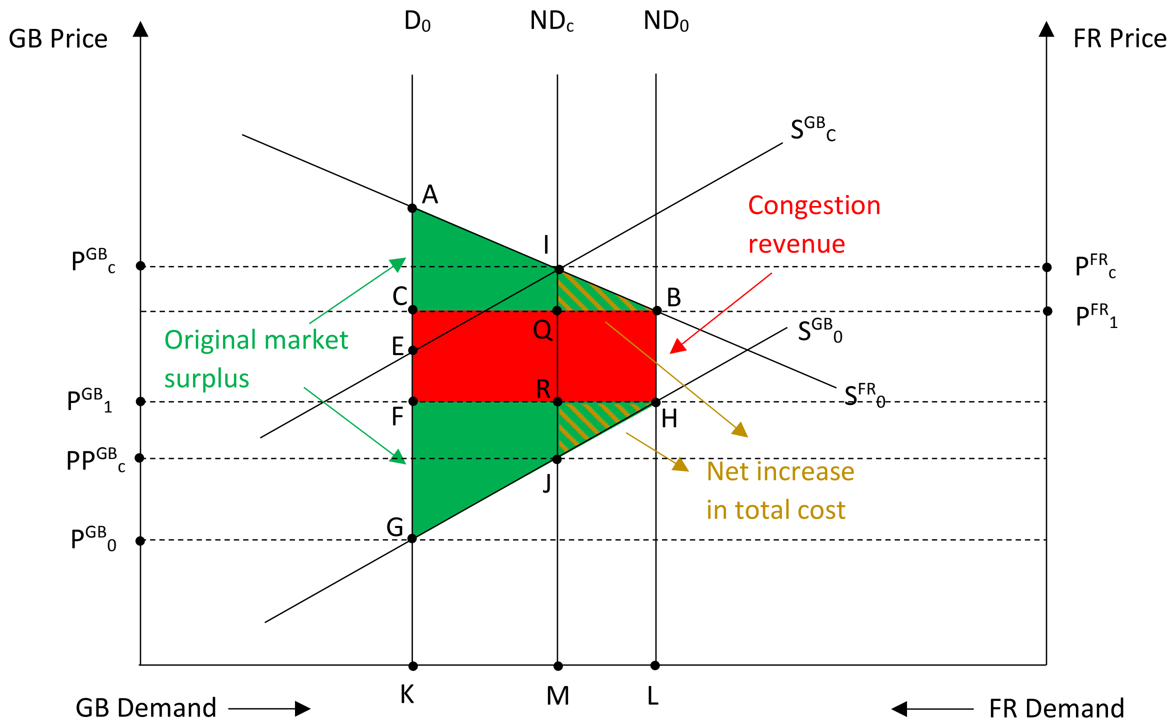

Figure A.6: Impact of CPS on Imports and Surpluses, GB Exports from Full to Partial Capacity

Differences between the day-ahead scheduled commercial exchange and the actual physical flows are due to intraday and balancing market trading. Newbery et al. (2019a) find that GB would rather reduce its day-ahead import from IFA in early morning hours (00:00-07:00) because the cost of ramping fossil plants down and then up could be higher than the intraday cost of reducing its imports, which provide a flexible and cheaper alternative. We find similar results for BritNed by comparing the hourly averaged flows between the simulated day-ahead commercial exchange and the actual physical flow, as demonstrated by Figure A.7.[32]

Our calculations shows that during the electricity year 2015-2016, an equivalent of €13 million (4%) in IFA congestion income was retained and used to finance these reverse flows. The value is similar for 2016-2017 (€15 million, or 8%) and 2017-2018 (€18 million, or 9%) despite the non-trivial difference in yearly congestion income. For BritNed, the values are about half that for IFA, namely €4 million (3%) for 2015-2016, €8 million (6%) for 2016-2017, and €8 million

[32]These are *average* flows, concealing relatively large (e.g. 500 MW) flows on some days and zero on others.

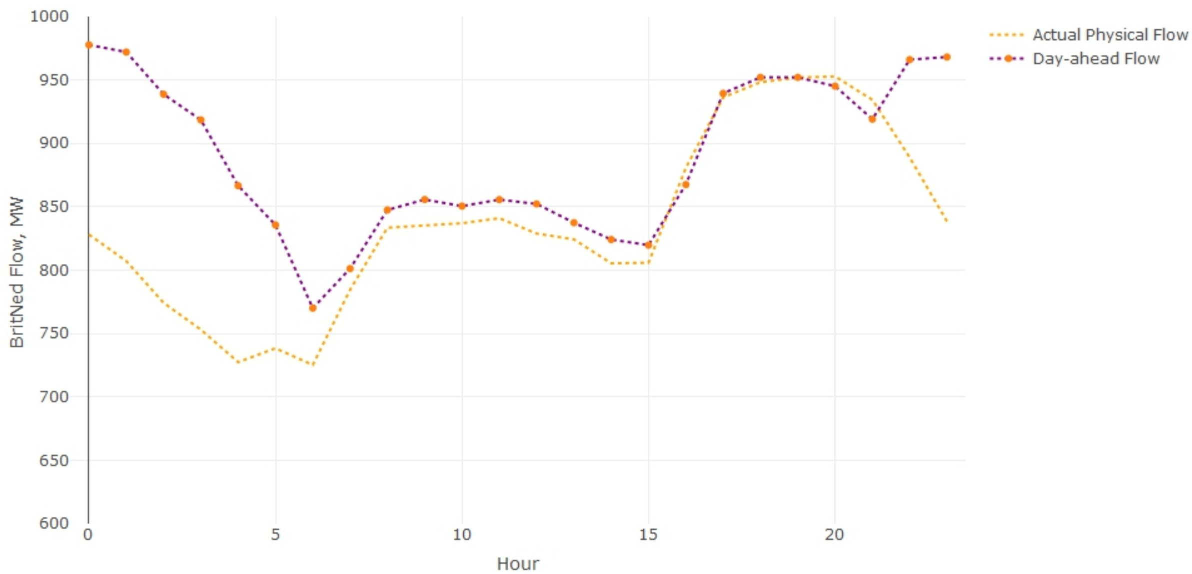

Figure A.7: Day-ahead *v.s.* Actual BritNed Commercial Exchange, 2015-2018

(7%) for 2017-2018.