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The private and social value of British electrical interconnectors

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ABSTRACT

Interconnectors have value for Britain, providing access to cheaper Continental power, security of supply, and managing increased renewables, prompting proposals for substantial new interconnectors. The EU Target Electricity Model requires interconnector market coupling via Day Ahead and IntraDay Markets. We examine the efficiency and value of uncoupled and coupled trading for the four DC interconnectors to GB, over different timescales from year ahead to intraday, and the social costs and benefits not reflected in the private benefits. Because the GB carbon tax is not replicated abroad it transfers some €65 m./yr to the foreign interconnector part-owners and creates distortions when trade flows change. IFA and BritNed have a commercial value of about €500 million/yr, create additional infra-marginal surplus of €25 m./yr, but suffer €30 m./yr deadweight loss from the asymmetric GB carbon tax. The island of Ireland was coupled in Oct 2018, dramatically reducing trading inefficiency. While further investment in interconnectors appears socially profitable, it is important to harmonise carbon taxes across the EU. If GB leaves the EU and is uncoupled, some of these trading gains would be sacrificed, but other financial markets may alleviate the cost of Brexit, making policies to enhance liquidity desirable.

1. Introduction

The growing literature on evaluating additional interconnectors sets out methodologies for their evaluation.[1] Their value is the increase in consumer welfare plus the decrease in total electricity system costs compared to the counterfactual. The social value measures all costs and benefits at efficiency prices, including all external costs of CO_2 emissions and other pollutants. Private value measures these at possibly distorted market prices. Any cost-benefit analysis must make predictions about future generation and other interconnector investments as well as their interaction. It needs to assess impacts on future emissions that will be affected by fuel and carbon prices. Policies for managing cross-border flows like market coupling, rules on access and access charging, renewables subsidies and the choice of discount rate for these very durable investments can strongly affect the results. It is unsurprising that plausible values for specific projects range from negative to strongly positive.[2] Rather than evaluating future projects, this paper looks at the value of existing interconnectors to GB as they have been impacted by the EU *Third Energy Package* and GB carbon taxes. It quantifies the contributions of market coupling for an important example of controllable DC links, and makes the case for wider adoption of an EU carbon price floor.

The EU attaches additional significance to interconnection. It announced €48 billion in priority energy infrastructure in 2018: "Properly interconnected electricity lines and gas pipelines form the backbone of an integrated European energy market anchored on the principle of solidarity. A fully interconnected market will improve Europe's security of supply, reduce the dependence on single suppliers and give consumers more choice. It is also essential for renewable energy sources to thrive and for the EU deliver on its Paris Agreement commitments on climate change."[3] This paper measures both the private and social value of electrical interconnectors to GB, including the value of increased

Abbreviations: ATC, Available Transfer Capacity; CfD, Contracts-for-Differences; CPS, Carbon Price Support; DAM, Day Ahead Market; EWIC, East-West Interconnector; FAPD, Flow Against Price Difference; FTR, Financial Transmission Right; IDM, Intra-day market; IFA, Interconnexion France Angleterre; PTR, Physical Transmission Right; SEM, Single Electricity Market of the island of Ireland; UST, Universal Standard Time; VRE, Variable Renewable Electricity

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[1] de Nooij (2011), ENTSO-E (2016b), Meeus et al. (2013), Turvey (2006).
[2] Aurora (2016), de Nooij (2011), National Grid Interconnectors (2014), Pöyry (2012, 2016, 2017), Policy Exchange (2016), Redpoint (2013).
[3] https://ec.europa.eu/info/news/completing-energy-union-eu-invests-eu48-million-priority-energy-infrastructure-2018-jul-16_en.

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security of supply. The more nebulous concept of solidarity falls into the category of non-monetary benefits. It is clearly challenged by debates in the UK to leave the EU.

Continental electricity systems are synchronised and meshed, so that flows across borders follow the laws of physics, not the dictates of national regulators. In contrast, Britain is connected to its neighbours by controllable DC links. Continental cross-border trade was initially managed by each national or sub-national system operator through a conservative assessment of Available Transfer Capacity (ATC) followed by redispatch if cross-border flows deviated too far from planned transfers. Increasing Variable Renewable Electricity (VRE, wind and solar PV) made this more difficult, often leading to a decrease in ATCs to increase security margins. Increased VRE added pressure to harmonise neighbouring Continental markets and to make better use of cross-border trade. The successful model of the Nordic market led to the *Third Energy Package* (Directive, 2009/72/EC) and with it the Target Electricity Model (TEM) that came into effect in 2014.

The Directive requires markets to be coupled. Interconnector capacity is cleared simultaneously with bids and offers from national markets through the European Day Ahead Market (DAM) auction platform EUPHEMIA. If all desired flows across coupled interconnectors are feasible, prices are equated on each side. If the flows at a single price are infeasible, prices are set to clear each zone and the interconnector capacity fully allocated so that electricity flows from low to higher prices zones. Continental markets are mostly self-dispatched energy-only markets, with which the DAM is immediately compatible. Although by 2014 GB had a capacity auction to allocate capacity agreements that paid for availability in stress hours, generators self-dispatch and the wholesale market clears through power exchanges and bilateral trades (DECC, 2014). Accommodating to the European Union's DAM was unproblematic and completed by 2014.

In contrast, Northern Ireland and the Republic of Ireland form the Single Electricity Market (SEM), a centrally dispatched regulated pool. Changing that design to align with the TEM required a derogation and a considerable delay to make the necessary changes. It took until 1 October 2018 for the SEM to be finally coupled to GB and to the EU DAM.

The early debates about the *Third Energy Package* demonstrated the inefficiency of interconnector use to argue for reform, specifically to change from ATC calculations to a flow-based market coupling model (e.g. KU Leuven, 2015). Newbery et al. (2016) estimated the potential benefit to the EU of coupling interconnectors to increase the efficiency of trading day-ahead, intra-day and sharing balancing services efficiently across borders. Their report for DG ENER (Newbery et al., 2013) provided estimates for the EU as a whole, based on evidence from ACER (2014). Adopting the ACER methodology but excluding the apparently miscalculated SEM-GB values (discussed below), Newbery et al. (2016) estimated the value of coupling at the day-ahead stage for a sample of interconnnectors at €12,670/MWyr of ATC capacity. Intra-day trading was estimated at a modest 4% of the benefits of coupling day-ahead, and complete shared cross-border balancing (still awaited) might be worth as much as 130% of day-ahead coupling. These estimates would be reduced if improved EU-wide integration improved price convergence and reduced arbitrage gains. Additional gains from reducing unscheduled flows and curtailment would not apply to GB coupled interconnectors.

Others (e.g. Gugler et al., 2018; Keppler et al., 2016) have studied the extent to which market coupling increased price convergence. They conclude that the large increase in VRE offset much of that price convergence but that further interconnection would improve price convergence. More importantly, the resulting social benefits would be substantial. de Nooij (2011) criticised the cost-benefit analyses of NorNed and East–West interconnectors. He argued that they lacked a suitable counterfactual in which generation investment responds to the presence or absence of interconnection and their impact on competition (particularly important for market concentration on the island of Ireland). He noted the VRE benefits or reduced curtailment that interconnectors could provide. Newbery (2018) compared investment in interconnectors with storage and flexible back-up as ways of reducing the cost of intermittency from VRE.

Substantial benefits from new GB interconnections to the Continent have been widely demonstrated (Aurora, 2016; National Grid, 2014; Policy Exchange, 2016; Pöyry, 2012, 2016; Redpoint, 2013). Pöyry (2016) finds four projects with a net social Present Value between €0.1bn/GW and €0.7bn/GW to GB. Pöyry (2016) concludes that 9–11 GW of interconnection capacity would provide a net benefit to GB, but additional investment faces falling marginal benefits, with negative net benefits in several market scenarios.

This paper uses the more extensive data from the ENTSO-E Transparency Platform[4] for the period after market coupling. It measures the private and social benefits of the existing controllable DC British interconnectors. This is motivated by the rush to propose and commission new interconnectors, the concern that some of the private benefits may arise because of Britain's introduction of a carbon tax on fossil fuel for electricity generation that is not matched by the rest of the EU, and, looming ever larger in public concern, the fear that the benefits of market coupling may be lost if the UK leaves the European Union (Geske et al., 2018).

This paper argues that:

- the private benefits of interconnectors are indeed large (relative to their cost);
- these benefits have been amplified by the increasing liquidity in markets over time-scales from more than a year ahead to intra-day trading;
- there are additional inframarginal social benefits not captured by trading from substituting cheaper imports for more expensive local generation;
- that the distortions caused by asymmetric carbon taxes are indeed substantial.

We make some final remarks concerning the potential costs of uncoupling existing interconnectors (but not on the possible impact of market uncoupling on planned or proposed future interconnector projects).

2. Interconnector trading

The British electricity system is linked to France through IFA (2000 MW capacity), to the Netherlands through BritNed (1000 MW), to Belgium through NEMO (since 31 Jan 2019, 1000 MW), to Northern Ireland through Moyle (maximum 500 MW),[5] and to the Republic of Ireland through EWIC (the East-West Interconnector, 500 MW). Northern Ireland and the Republic form the Single Electricity Market (SEM) so GB has two links to the SEM.

Interconnector capacity is sold forward in auctions held at various moments for year-ahead, season-ahead, quarter-ahead, month-ahead, day-ahead, intraday (and balancing).[6] The forward contracts, Financial Transmission Rights (FTRs) are sold as use-it-or-sell-it, meaning that any capacity bought in forward markets not nominated in the day-ahead market (DAM) is released into the DAM and the holders of the

[4] At https://transparency.entsoe.eu/.

[5] From Nov 2017 to Nov 2019 exports from Northern Ireland were 80 MW firm but an additional 420 MW may be released by GB if there is spare GB transmission capacity, while exports to Ireland were 450 MW in winter and 410 MW in summer. See http://www.mutual-energy.com/electricity-business/moyle-interconnector/trading-across-the-moyle-interconnector/.

[6] IFA data are available at https://damasifa.unicorn.eu/Long-term_Auction_Statistics.asp while BritNed data are available at https://www.britned.com/participants-portal/explicit-auctions/. Balancing actions are not yet fully coupled through markets but are available to System Operators.

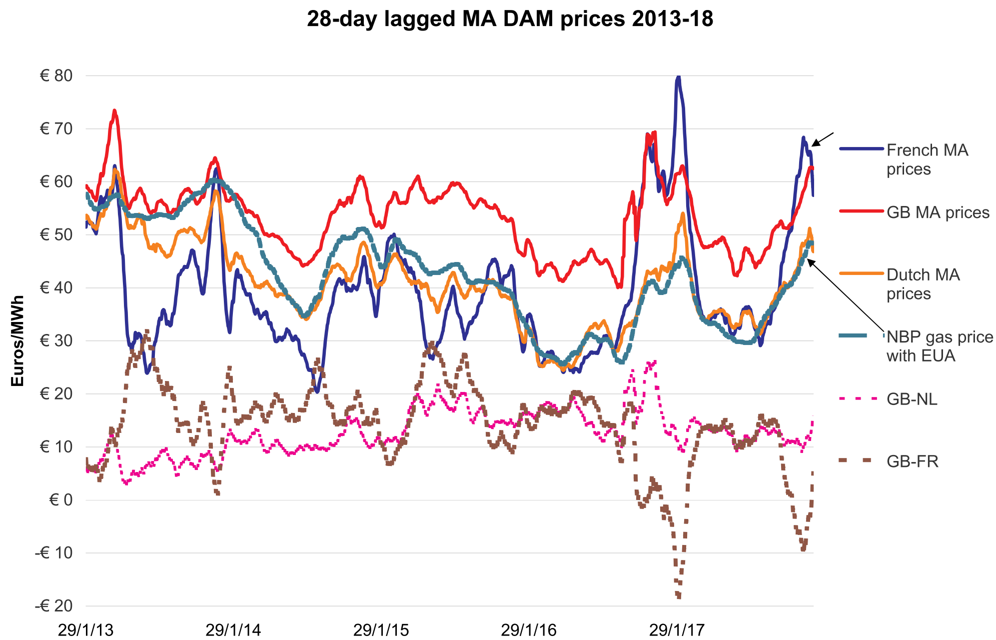

Fig. 1. Prices in the Day Ahead Market in Britain, France and Netherlands. Source: ENTSO-E Transparency Platform. Note: graphs in same order as legend.

FTRs receive the DAM price difference. In practice, about 90% is sold forward, but all FTRs are cleared in the DAM, which is run at noon (CET) to determine prices for each hour of the following day.

FTRs have the same advantage as Contracts-for-Differences (CfDs) in local markets. The contracting parties lock in a strike price, *s*, on which they can contract with consumers for an agreed price. If in the specified hour, the spot price *p* in the relevant market (e.g. the DAM) is above the strike price, the CfD buyer (retailer) pays the DAM price *p* and receives from the CfD seller (generator) the difference (*p-s*), making the effective cost just the strike price, *s*. The CfD seller, who has sold in the spot market at *p,* has to pay *p-s*, so effectively receives the strike price, *s*. (The argument is symmetric if $p < s$.) Both buyer and seller are thus hedged at the strike price regardless of what happens in the spot market. The critical advantage of these financial forward contracts is that dispatch is driven by DAM prices, not the strike prices. If a supplier expects to generate and sell at *s,* close to its marginal cost, *m,* and if $s > m > p$, the supplier would not generate. Instead a lower cost generator produces, meeting demand at lower cost.

After the DAM auction there are a number of intra-day market (IDM) auctions for GB and the SEM, while on the Continental most intra-day trading is conducted continuously on EPEX SPOT. Neuhoff et al. (2016) demonstrate that this is inferior to periodic auctions by comparing the German experience with both formats. Finally, System Operators take control close to dispatch and may schedule balancing flows across interconnectors, calling on bids from Balancing Responsible Parties. The eventual aim of the Target Model is to clear balancing bids across borders. Section 9 gives more details and analysis of these various markets.

The interconnector owners sell the FTRs forward at what is the market's estimate of the cross-border price difference, augmented by the value of optionality, as FTR holders are not required to honour unprofitable FTRs. The owners also receive the cross-border price difference for any unsold capacity, but the IDM is mainly a market between other participants. The revenue from trading over different time periods is therefore not necessarily the revenue received by the owner.

The revenue will depend on price differences, but the real value is larger, as the ability for GB to import or export up to 5000 MW makes a potentially appreciable difference to the market clearing price in both GB and France and reduces the overall cost of meeting demand. This additional benefit is discussed below, together with possible distortions to trade arising through differences in carbon pricing in coupled markets.

Fig. 1 shows the lagged 28-day moving average of the DAM hourly prices in GB, France (FR) and Netherlands (NL), as well the cost of generating electricity in a 50%[7] efficient Combined Cycle Gas Turbine, including the cost of the EUA.[8] The gas cost explains some of the price variation, and was a closer match in NL, where gas was likely to be the marginal fuel much of the time, as it was more costly than coal until mid-2018, when the EUA price rose sharply.

GB and NL have very similar fuel mixes so one might expect similar wholesale prices. Fig. 1 shows that during 2015–2017, there was a persistent difference with GB on average €14.98/MWh more expensive than NL, while FR is only on average €2.86/MWh more expensive than NL. Over the whole period, GB and NL had price differences of less than €0.5/MWh (effectively the same) 2% of the time, and less than €5/MWh 28% of the time. Price differences across IFA were less than €0.5/MWh (also effectively the same) 19% of the time, and less than €5/MWh 31% of the time.

One obvious reason for the higher GB price is that since 2013, GB (but not Northern Ireland) has levied a carbon tax on fuel used to generate electricity (the Carbon Price Support, CPS). In April 2015, the CPS roughly doubled from about £9 to £18/t CO_2, substantially raising the cost of fossil generation. This made coal the more expensive fuel in GB. Chyong et al. (2019) estimated this carbon tax (£18 or €20/tCO2) would increase the system marginal cost by £5 to £8/MWh from 2015 to 2017 by identifying the marginal CO_2 emissions in each half-hour (t CO_2/MWh) and multiplying that by the carbon tax (£/t CO_2). Guo et al. (2019) do not reject the null hypothesis that the CPS has been fully passed through to GB DAM prices, or raised GB price about £8/MWh (€10.5/MWh) before accounting for interconnector flow changes, or €8.5/MWh after responding to flow changes. This only accounts for two-third of the average price excess. As NL is tightly connected to a highly meshed Continental grid, NL prices may be depressed by cheap nuclear French power and high renewable volumes from Denmark and

[7] This is the Lower Heat Value, which is 90% of the Higher Heat Value.

[8] The EUA is the EU Allowance price for CO_2 set by the Emissions Trading System. Gas contains 0.185 tonnes CO_2 per MWh heat content, hence 0.185 EUA is added to the price of gas. The cost is twice this augmented price assuming 50% efficiency at Lower Heat Value.

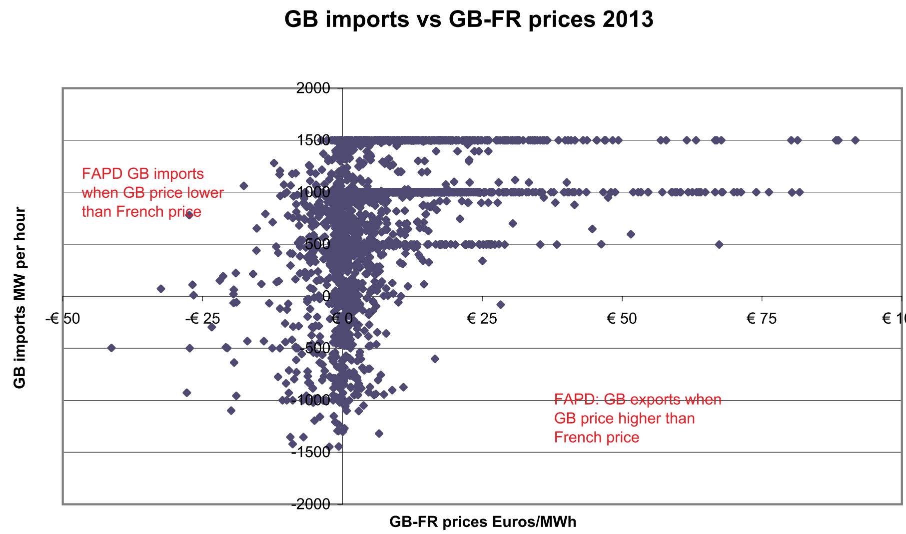

Fig. 2. Ex post Net GB imports over IFA *vs.* day-ahead price differences during 2013. Source: GB price from N2EX, FR from EPEX.

Germany (Blume-Werry et al., 2018; Hirth, 2018).

3. The impact of market coupling

Britain has been coupled to France through IFA and the Netherlands through BritNed since 2014. The SEM was only finally coupled on 1 October 2018, while NEMO was only commissioned on 31 January 2019 and is not considered in this paper.

3.1. IFA day ahead coupling

A standard measure of the success of coupling is that trade flows from lower-to higher-priced zones, and failure is measured by Flows Against Price Differences (FAPD). Fig. 2 shows trading across IFA in 2013 before the markets were coupled. If the GB price is higher than the French price (adjusted for losses to the half-way point of 1.17%)[9] then GB should import from France (top-right hand quadrant), but if GB prices are lower (i.e. GB-FR prices are negative) then if GB imports it does so in the wrong direction as a FAPD.

It is clear in Fig. 2 that many observations cluster at multiples of 500 MW, the capacity of each of the four lines. That is because of line restrictions, either because of their unavailability,[10] or because of network limitations within France or GB.[11] Quoting the footnote source "In normal operation, IFA flow is not permitted by the GB Network TSO to change at more than 100 MW/min for frequency management purposes. … Daily Implicit Auctions are expected to utilise IFA capability more fully (function of the daily price difference), thereby causing large hour-hour variations of power transfer more frequently (2 GW and vice versa)." If flows were to be reversed, the 4000 MW change would require 40 min to complete. This can explain some of the FAPDs but not all.

The average 2013 GB imports were 1189 MW at an average GB price excess of €15.83/MWh, giving an average value of €26,405/hr. This is the loss-adjusted price difference times the value of the physical flow, reduced by €3642/hr because of FAPD. As GB was almost always more expensive than France, the percentage of FAPD was modest at 10% (ignoring small perverse price differences). The value destruction was as much as 14% of the total value of €231 million/yr at €31.9 million/yr.

Once IFA was coupled the situation changed. Fig. 3 shows the scheduled flows — the amounts allocated in the DAM auction — in MW against DAM price differences for 2017.[12] ENTSO-E publishes the ATC in each direction, and for lengthy periods 500 MW (one of the four lines), and occasionally 1000 MW was out of service. The clustering of flows at units of 500 MW is very clear and reflects the periodic unavailability of one or more lines. The value of the actual flows using the ATC values for capacity is 99.33% of the maximum feasible flows allowed. Changes in the direction of flows by trading in the IDM and BM occur less than 1% of the time. The value of DAM congestion rent in 2017 was €178 million, with the (loss-adjusted) GB price on average €6.58/MWh higher than in France (roughly half the average for the period 2015-18 shown in Fig. 1).

Fig. 4 shows the percentage of Available Transfer Capacity (ATC) actually used (after further adjustments in subsequent trading on the day) against DAM price differences for 2015. The DAM trading value in 2015 was €270 million (compared to €231 m in 2013).

3.2. BritNed coupling day ahead

Fig. 5 shows the scatter of GB exports (or negative imports) against the DAM GB price less the Dutch price for the electricity year (April 1 to Mar 31) 2015–16,[13] adjusted for losses totalling 3%.[14] Again we assume that the DAM clears efficiently, so that all deviations in the actual flow compared to efficient use arise from intraday and balancing actions.

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

[10] The IFA capacity is shown on the Nordpool website at http://www.nordpoolgroup.com.com/Market-data1/N2EX/Capacities/UK/Hourly/and BritNed gives information at https://www.britned.com/.

[11] E.g. "Different requirements from NWE TSOs inclusion of the Allocation Constraints (as foreseen in the current draft Capacity Allocation and Congestion Management Network Code, CACM). Allocation Constraints are to be respected during the capacity. Allocation Constraints may include: operational security constraints, ramping constraints, transmission interconnector losses. The resulting IFA Daily Flow will be set by Euphemia taking into account the Allocation Constraints as submitted by the Operators during the pre Explicit Daily Auction invoked during the Implicit Daily Auction Window Notice (Rule 5.4 Schedule IV an E4.4.4). (IFA Interconnector within the NWE Price Coupling solution).

[12] RTE publishes forecast flows after the DAM auction clears but before flows occur, so they represent the allocation at the DA stage. ENTSO-E publishes scheduled flows that record the actual flows over all time-scales including intraday and balancing and these are used in Fig. 5 and below to calculate subsequent changes in flows.

[13] There are many missing price values in the first quarter of 2015.

[14] Source: https://www.britned.com/about-us/operations/.

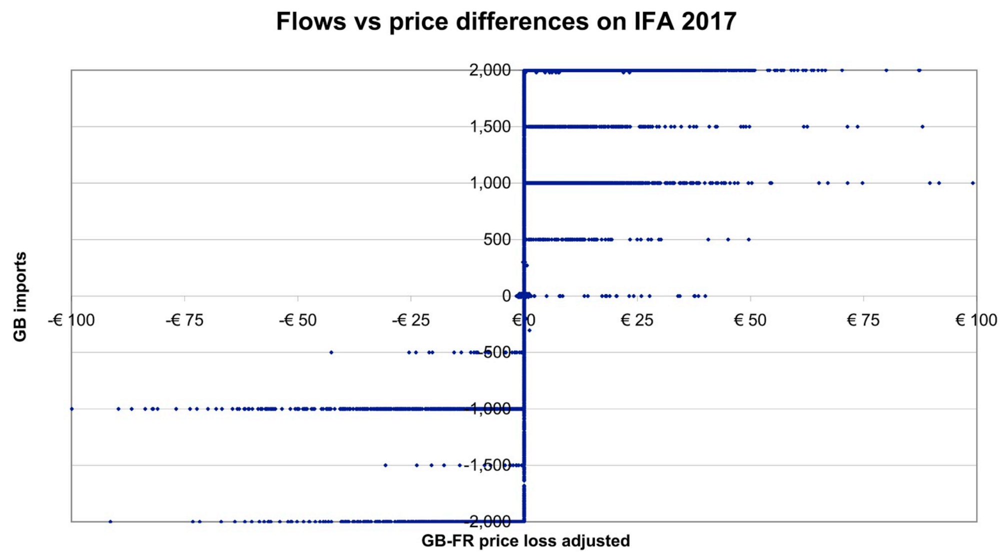

Fig. 3. Ex ante scheduled net imports into GB over IFA vs day-ahead price differences, 2017.
Source: Prices: N2EX for GB, ENTSO-E for FR, data truncated at +/−
€100/MWh. Flows are RTE forecast flows.

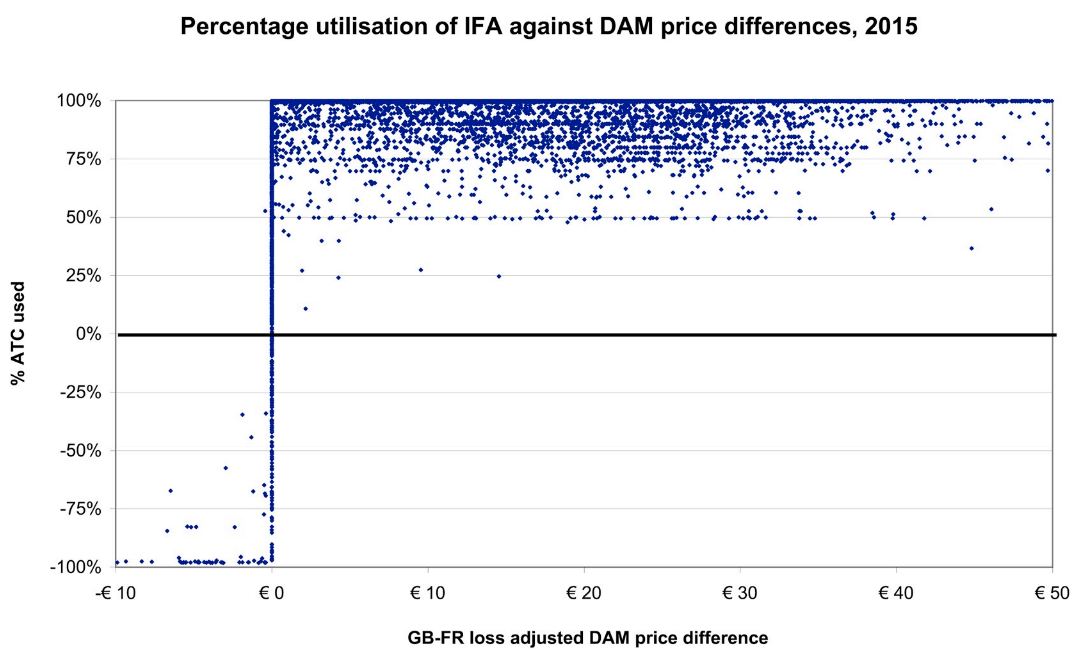

Fig. 4. *Ex post* GB net imports from France as a percent of ATC against the GB minus French (FR) price differences, calendar 2015. Sources: Flows and prices from ENTSO-E Transparency platform. Truncated at -€10 and +€50/MWh.

Almost all of the time actual trade is in the same direction as the flows determined in the DAM. The DAM 2015–16 revenue was €135 million, of which €5 million was bought back and retraded intraday, discussed in the next section.

Another performance metric is the percentage of potential congestion revenue, assuming the whole 1000 MW are available 100% of the time. From 2015–18 this measure of efficiency is 95% (€12,276/hr vs €13,378/hr) yielding €107 million/yr. Fig. 6 shows the evolution of two measures of congestion revenue. The darker line (DAM Revenue) gives our estimate of the market value of the interconnector, the loss-adjusted price difference times the scheduled commercial exchanges. The other line gives ENTSO-E's figures for the total revenues received by transmission companies, combining the auction revenues where capacity is sold in advance and the value of the remaining capacity in the day-ahead market, given price differences and flows.[15] The two measures are clearly quite different, in contrast to the recent IFA experience,[16] and cannot be explained by the difference between scheduled and actual flows (which are small).[17] It may be that it is the result of contracts over different time periods (year, quarter, month, day ahead, and intraday) where the contract prices will inevitably differ

[15] Congestion income is defined in Appendix B and ENTSO-E (2016a).

[16] See *ENTSO-E Transparency platform.*

[17] ENTSO-E relies on data from shippers and counterparties, and may be subject to later revision that is not necessarily reflected in the ENTSO-E data. It appears that TenneT uses a different source for DAM data (closer to German than Dutch prices) and that may help explain the discrepancy.

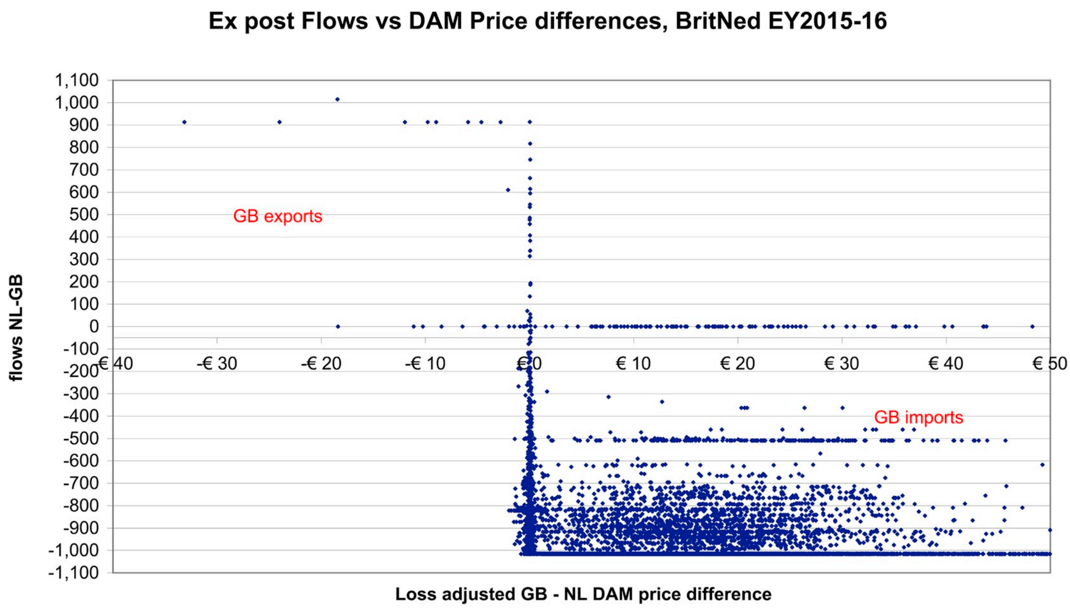

Fig. 5. Trade vs price difference over BritNed, Electricity year 2015–16. Note: truncated at €50/MWh.

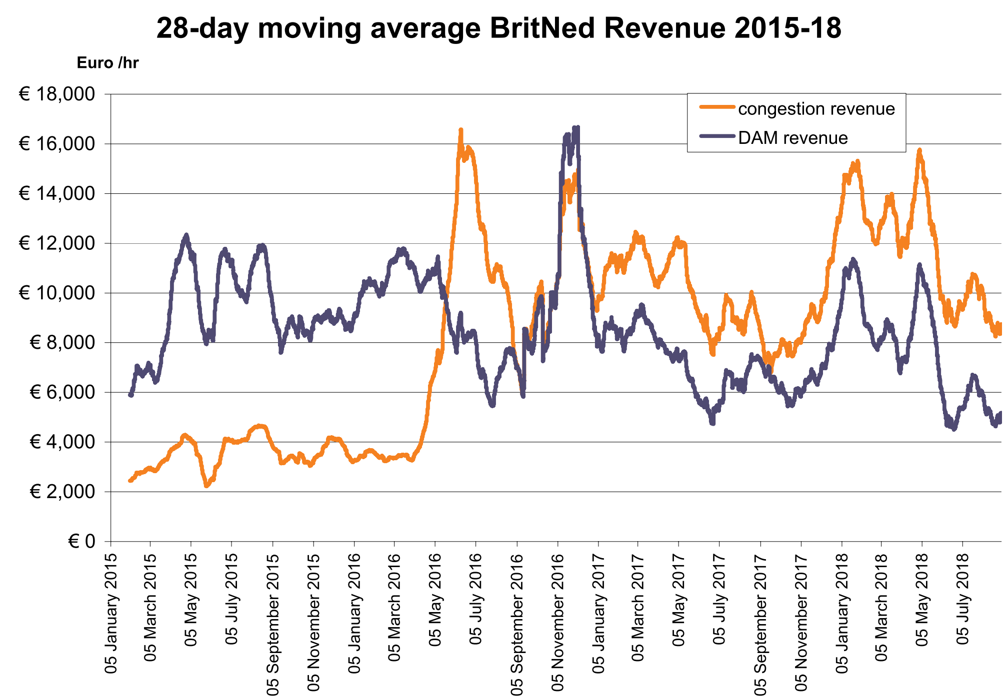

Fig. 6. Congestion revenue estimated from DAM prices and recorded congestion revenue.
Source: ENTSO-E Transparency platform.

from the DAM price. Over the whole period the two are almost identical, but the ratio of the DAM revenue to the congestion revenue falls from 268% in 2015 to 63% in 2018. Risk aversion could possibly explain differences in prices traded ahead and intraday, with an apparent shift from a preference for intraday risk in the early period to a desire to hedge ahead of time later (perhaps driven by a lack of liquidity in the forward markets). The evolution of these forward markets is considered in section 9.

3.3. The effect of the Carbon Price Support

Guo et al. (2019) estimated that the CPS increased net import over IFA in electricity years 2015–2018 from 1.7 TWh/yr without the CPS to 11.7 TWh/yr with the CPS, or on average 10 TWh/yr of extra net imports are attributable to the GB CPS. As France owns half of IFA, the CPS profited their share of IFA by roughly €40 million/yr. UK consumers paid more, National Grid profited from its share of IFA,[18] and the Government received extra CPS revenue as the CPS is in effect a carbon tax that flows to the Treasury. The estimated impact on Britned's total congestion revenue was to increase it by €52 million/yr, about half of the DAM congestion revenue under market coupling. Again, this

[18] This is estimated from half the difference in trade revenue with and without the CPS.

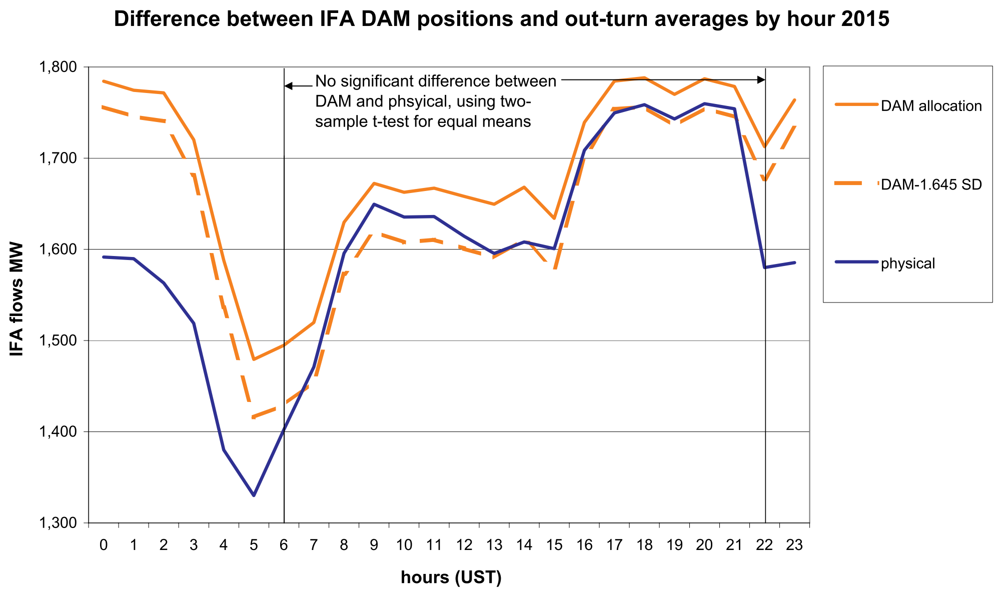

Fig. 7. Difference between DAM positions and out-turn averages by hour (UST) for 2015.
Source: ENTSO-E Transparency platform.

is split half to National Grid and half to TenneT.

4. Intraday timeframes

4.1. IFA post-DAM trading

Fig. 3 showed the capacity allocated in the DAM auction while Fig. 4 showed the actual flows after subsequent trading during the day. There are frequent positive price differences but less than 100% utilisation, because the actual flows are after trading in the intraday and balancing markets. Coupling implies that if there is a positive (loss-adjusted) price difference in the DAM, the full capacity is allocated at that stage. Subsequently capacity is made available subject to not exceeding the ATC. Thus if GB is importing at 100% of ATC after the DAM auction (2000 MW), it is only possible to release flows in the IDM from GB to FR, of which 4000 MW is available. Conversely, if the GB-FR price difference is negative in the DAM, then GB would expect to export, but could buy imports up to 4000 MW after the DAM auction has closed. If the change in direction exceeds the amount bought in the DAM, then there will be an apparent FAPD, based on the DAM prices and the actual flows settled after all the later markets have cleared.

We can make an approximate estimate of this post-DAM trade. In the DAM, the value of IFA assuming full utilisation is €270 million for calendar year of 2015. After the DAM, €13 million was bought back and used for reverse flows. As GB imported 97% of the hours in 2015, almost all the subsequent actions were GB exporting to France. At the very least traders must have bought out the GB importers at the price they paid in the DAM, unless the GB balancing price were less than the DAM value and the traders now wanted to reduce their demands. If the French balancing prices are higher than the GB DAM price (GBDAM), and if the traders could sell intra-day at something approaching the final French balancing price (FRBP), then the added value should be somewhat less than the FRBP-GBDAM price difference. For each shortfall of the actual flow and the ATC this should give an estimated value of reversing the flows. The results for 2015, taking only cases where the French balancing price is higher than the GBDAM, and summing over the changes in flows, is an additional €4 million. This ignores the small number of hours in which GB exports in the DAM and then reimports.

Fig. 7 shows the difference between the average daily patterns for commercial forecast (volumes cleared in the DAM) and the real (physical) flows after all IDM trades and any balancing actions for IFA in 2015. The one-side 95% lower confidence interval for the DAM forecast is also plotted as the dashed line.[19] It is clear that the major differences are off-peak night and to a lesser extent early afternoon. An obvious explanation is that GB is constrained by the position its generators need to be in to meet the early morning ramp-up (both to FR for their earlier peak and then for the GB peak). Rather than incur more costly ramping down and then up in GB, imports are reduced as a cheaper flexibility option. Closer examination shows that the main deviations are in the summer months, and that in these hours pumped storage is at maximum demand, while fossil generation is at minimum load. Hence, the main source of flexibility is to reduce imports relative to the earlier day-ahead (or even further back) position. Imports, mainly from France and the Netherlands, have been marginal in GB 13% of the time in 2017 (Castagneto Gissey et al., 2018).

4.2. BritNed post-Day Ahead Market trading

We can estimate the value of post-DAM trading from the capacity bought back (or unused when DAM prices are equal).[20] The extra revenue is the difference of the Dutch balancing price[21] less the GBDAM value, times the minimum of the available interconnector value and the net balancing volume in the Dutch balancing market. The 2015 amount is €7 million.

4.3. Assessment of coupling

Coupling has considerably improved the value of IFA and BritNed,

[19] This indicates that for some hours the difference can be (close to) zero while for some others the difference can be relatively large (500 MW or above).

[20] In answer to a query, an analyst at BritNed replied: “We offer into the intraday auctions whatever capacity is available in either direction following the long-term nominations and day-ahead market coupling completion. Hence, if we have maximum 1 GW scheduled flow into GB at day-ahead, we will offer 2 GW into the Netherlands through the intraday process. If we are not at maximum scheduled flows, then capacity will be offered in either direction up to the maximum. We don't have any specific pre-set amounts (blocks) for the intraday and there are no reserve prices, etc.” More details are available on the website https://www.britned.com/participants-portal/explicit-auctions/.

[21] Taking the up-regulation prices.

delivering efficiency in the DAM auction, while allowing adjustments after the DAM auction closes. These post DAM adjustments have modest value, perhaps because the underlying price differences are so large. This is consistent with the earlier estimates of Newbery et al. (2016) that the IDM only adds about 4% to the DAM value. The CPS has, however, because it applies only in GB and not with here trading partners, introduced a trade distortion. The impact on the social value is discussed below.

5. Interconnectors to the Single Electricity Market

Britain has two connections to the SEM, finally coupled on 1 October 2018. Before then flows were highly inefficient, with FAPD roughly 50% of the time since 2015.[22] Before coupling the SEM was a centrally dispatched audited bid pool in which indicative prices were published day-ahead on the assumption of no constraints.[23] Settlement took place four days later at the outturn prices based on the actual security-constrained dispatch, typically different from the *ex ante* prices. About 25% of the time the difference was material. Traders wishing to use the interconnectors therefore based their decisions on inaccurate prices, or alternatively, ignored these *ex ante* prices and flowed according to their forward purchases. ACER (2014) estimate the cost of this inefficiency (for both interconnectors) at €54 million in 2013 and €69 million in 2014, although Newbery et al. (2016) considered this a substantial over-estimate. Their estimate for Moyle in 2012 was €7.5 million compared with ACER's (2014) estimate in 2012 of €21.8 million.

Table 1 below gives the SEM Committee's (2011) estimates of the potential annual gain in social welfare of using the two interconnectors efficiently. SEM (2011) consulted Moyle interconnector users, finding they identified the deadband as €10–15/MWh between half hourly GB prices and expected *ex post* SEM prices, within which participants would not risk trading. Reasons included the very different gate closure times and *ex-post* pricing in the SEM, the lack of liquidity in day-ahead markets in both Ireland and GB and the risk of incurring Transmission Network Use of System (TNUoS) triad charges. Ofgem removed TNUoS charges for interconnectors users, reducing the deadband. At €5/MWh, the inefficiency would be €30 million/yr for both interconnectors. This intermediate estimate appears defensible.

Since 1 October 2018 both interconnectors have been efficiently coupled, but whereas flows before GB introduced the CPS were mostly from GB to the SEM, now they are often in the opposite direction, despite the SEM having higher cost plant and greater carbon intensity. The social value of these interconnectors is thereby severely compromised by the lack of a SEM carbon tax.

6. The value for security of supply

Faced with growing evidence (and good economic theory; Newbery, 2016) that the liberalised electricity market was failing to invest adequately to deliver security of supply (DECC, 2010), the UK Government passed the *Energy Act 2013* (HoC, 2013). Periodic (usually annual) auctions would procure sufficient capacity to deliver the reliability standard of an expected 3 h loss of load per year (see e.g. Newbery, 2016; Newbery and Grubb, 2015; Grubb and Newbery, 2018). National Grid was charged to recommend the capacity to procure. In the first year National Grid (2014) assumed zero net contribution from interconnectors (but considered sensitivities up to 100% of 2.25 GW imports from Continental Europe). The Panel of Technical Experts,[24] advising on National Grid (2014), drew on reports commissioned by Ofgem and the Government[25] to argue that interconnectors, which are licensed separately and treated differently to generators, "can deliver power to GB and as such they should be treated in the same way as generation, with some probability, to be assessed, that they will be unable to deliver imports during GB stress events."

Table 1
Moyle and East West interconnectors (950/910 MW imports, 580 MW exports). Source: SEM-11-023 based on data for 2010 from the Moyle. Note EWIC was not commissioned until 2012.

Deadband (€/MWh)	Consumer surplus (€ millions)	Producer surplus (€ millions)	Total potential gain in social welfare (€ millions)
0	28.6	12.1	40.7
5	23.7	7.0	30.7
10	19.6	4.1	23.8
15	16.6	2.8	19.4

Subsequently, the European Commission required the UK Government to allow EU generators to bid into the capacity auctions. The compromise interim agreement was that interconnectors could bid. National Grid was charged to calculate interconnectors' de-rated contribution to capacity adequacy. National Grid (2015) estimated these derating factors as 50–70% for IFA, 62–80% for BritNed, and 2–10% for SEM for 2019–20. Estimates by Pőyry (2018) for 2022–23 revised these to IFA, 59–86%, BritNed, 27–62%, SEM, 24–42%, and included NEMO (35–67%) and the proposed link to Norway (90–100%). Successful bidders are granted capacity agreements to deliver their de-rated capacity. The System Operator gives those holding agreements 4 h' notice of a stress period, at which time they are required to be available to be dispatched or face a penalty. However, on 15 November 2018, the EU Court of Justice ruled the capacity agreements violated State Aid and they were immediately suspended.[26] The Government is working to ensure they will be reinstated as soon as possible.[27] We assume interconnectors provide capacity value even if not (yet) recognised by EU courts.

This would seem to be easy for interconnectors to deliver. Either they are already flowing to GB (in which case they have delivered their obligation), or the interconnector owner can buy import capacity into GB through the intraday auction. We can estimate the capacity value of the three interconnectors using the results for the 2016 T-4 for delivery in 2020–21. IFA was awarded 1193 MW, BritNed 888 MW, and SEM 252 MW. The auction cleared at a price of £22.50/kW/yr giving an annual capacity value for IFA and BritNed of £46.8 million (€57.3 million/yr). Prices in the capacity auction have been volatile. The following year the T-4 auction for delivery in 2021–22 allocated 1003 MW for BritNed, 1260 MW for IFA, and 140 MW (just Moyle) for SEM. The auction cleared at £8.40/kW/yr, giving their total capacity value as £19(€22) m/yr for IFA and BritNed (National Grid, 2018). In that auction for the first time new interconnectors were successful: Nemo (GB-BE, 1000 MW) was granted 750 MW, IFA2 (1000 MW) 715 MW and ElecLink (1000 MW, GB-FR) 690 MW.

The fall in auction prices may reflect a smaller amount of "missing money" (Grubb and Newbery, 2018) now that National Grid has defined and procured more short-run flexibility products, but could reflect

[22] Fig 14 in https://www.semcommittee.com/publication/sem-18-033-sem-monitoring-report-q1-2018.

[23] See the explanation of price setting in https://www.semcommittee.com/publication/sem-18-033-sem-monitoring-report-q1-2018.

[24] Newbery was a member of this Panel but writes in his personal capacity, (*footnote continued*) drawing only on information in the public domain.

[25] Pőyry (2012), Redpoint (2013).

[26] See http://curia.europa.eu/juris/document/document.jsf?text=&docid=207792&pageIndex=0&doclang=en&mode=req&dir=&occ=first&part=1&cid=1430154.

[27] See https://www.gov.uk/government/collections/electricity-market-reform-capacity-market?utm_source=ba1f7ca5-ac48-41a8-afbd-9527d207a185&utm_medium=email&utm_campaign=govuk-notifications&utm_content=immediate.

falling demand and adequate existing capacity. Nevertheless, 4.1 GW new capacity was procured, of which 1.2 GW of demand-side response cleared at this low price.

7. Commercial profitability of IFA and BritNed

BritNed cost about £$_{2018}$ 560 million (€640 million) and was commissioned in 2011. Company accounts are available for BritNed[28] and provide a break-down of various sources of income. The 2017 arbitrage revenue was €92 million calculated at DAM prices, but as BritNed sells the larger part forward, actual arbitrage revenues were considerably higher. The company accounts for 2017 (2016 in brackets) show net explicit revenues as €115 million (€174 m), net implicit revenue €16 m. (€20 m) and "other revenue" (defined as the value of the frequency response service, participation in the GB Capacity Market and other minor ancillary services such as Intertrip services) as €15 m. (€14 m). Administrative expenses were €32 million. Operating profits (after admin expenses) in 2015 and 2016 were over €200 million, or a net private rate of profit of over 30%.

Table 2 summarises the DAM arbitrage revenue for IFA and BritNed during electricity years 2015–2018. However, the company accounts show actual revenues from forward and spot trading at 140% of the DAM value in 2017 and 134% for 2016, shown in Table 3 as additional forward trading value to be added to the value at DAM prices. Given that flows over IFA are probably more predictable, this additional revenue may be smaller and also appear from Fig. 10 below to be converging on the DAM value. We take a conservative additional 10% for forward trading on IFA. The three-year average for the two interconnectors is €375 million/yr at DAM prices, or about €125 million/GW/yr over the longer period 2015–18, or €125/kW/yr.

Table 3 summarises the various sources of commercial value. It is hard to be more precise than that IFA and BritNed contribute a capacity value of between €22–57 million/yr, or between 6 and 15% of their DAM arbitrage value. Our earlier estimate shows that the intra-day value is about 3% of DAM value, or about €10 million/year. Forward trading for BritNed (and presumably IFA) considerably increases the revenue received by interconnectors, perhaps by €50 million/yr for BritNed and €25 million/yr for IFA. Netting out the capacity payments from other payments in the accounts suggests very modest values for balancing and ancillary services, or a notional €5 million/yr for both interconnectors taken together. Table 3 summarises a central value (around which there must be considerable uncertainty) for the annual commercial value of trading over IFA and BritNed in 2015–2018, just under €170/kWyr.

8. The social value of interconnectors

Profitability is only a good measure of social value if prices are not changed by the interconnector flows and the prices measure social costs and benefits. Neither is currently true for GB trade. Table 3 estimated the commercial profitability, not the social profitability, as it includes the extra revenue from the asymmetric application of a carbon tax in GB, but not on the Continent. The French may claim to be delivering nuclear-fuelled electricity over IFA, but whether that is the marginal source is less clear, as either France will be importing from fossil-intensive neighbours or exporting less nuclear power there and inducing more fossil generation to meet demand. Castagneto Gissey (2018) estimates the French marginal share of carbon-intensive generation was 11% between 2015 and 2017, supporting this assessment.

Table 2
Day-ahead Arbitrage for IFA and BritNed in € million, electricity years 2015–2018.

Electricity years	DAM Arbitrage (million €)	
	IFA	BritNed
2015–2016	318	148
2016–2017	197	137
2017–2018	211	113

Table 3
Commercial value of trading over IFA and BritNed in € million/yr.

DAM arbitrage	€ 375
IDM trading	€ 10
Extra FTR revenue	€ 75
ancillary services	€ 5
capacity value	€ 40
Total	€ 505

Blume-Werry et al. (2018, Fig. 2.), suggest that 75% of the time foreign generators set the Dutch price. In their 2020 simulation, gas sets the price 35% of the time, coal 18% and very carbon-intensive lignite 11% of the time, with the balance zero-carbon sources (nuclear, hydro and RES). If coal is twice the carbon intensity of gas, and lignite three times, then the effective carbon intensity of Dutch electricity might be 0.35 tonnes/MWh and this would add roughly €7/MWh to the social cost[29] of Dutch exports to GB, or about the same as the CPS added to GB electricity. Assuming the impact of the Netherlands implementing the GB carbon tax is the same as removing the GB CPS, Guo et al. (2019) estimate that GB would import 3.6 TWh/yr less from the Netherlands, reducing market revenue by €54 million/yr.

In Fig. 8a (left panel) AB is the supply curve of FR exporting over IFA in the DAM to GB, and DC is the demand by GB to import over IFA (including the CPS, taken here as the correct additional tax to add to the EUA to give the social cost of carbon). The maximum export over IFA is OX, and the DAM clears at a French price of G and at a GB price of F. The value of trade is FG * OX, but the full social value of the interconnector is the area ABCD, which has a value ½(AD + CB) * OX. The revenue thus understates the social value by the difference between these two areas (in this case removing the asymmetry in carbon taxes reduces the deadweight cost, and amplifies the infra-marginal surplus, instead of the asymmetric carbon tax reducing it).

To give an approximate estimate in the case of IFA, if GB prices fall by €1/GW extra demand[30] and the French price rises by €0.5/GW, then the difference between prices with no trade and with the full 2 GW of trade is €3/MWh if after coupling the full 2 GW are used. The extra uncounted social value would then be ½ x €3/hr x 2000 MW or €3000/hr. More generally, if prices converge after coupling, and the volume traded is X MW, the missing social value will be ½ €1.5.X/1000*X/hr. In 2015, the average volume of trade was X = 1641 MW, so in this case the average infra-marginal surplus was €2020/hr, or €17.7 million/yr. For BritNed, the average physical flow in 2015 was 929 MW. If GB prices fall by €1/GW of demand and NL prices raise by €1/GW, then the infra-marginal surplus was €863/hr, or €7.6 million/yr.[31] The total

[28] At https://www.britned.com/participants-portal/key-links-and-documents/annual-accounts/The company accounts for National Grid Interconnectors (owner of half IFA) reports consolidated turnover of £93 m for 1/4/16–31/3/17 and £96.7 m for the following year, expenses of £22.9 m and £22.3 m respectively, but no breakdown between arbitrage and ancillary service revenue.

[29] This assumes that the social cost of CO_2 should be £18/t CO_2 higher than the EUA price, based on the GB CPS value in 2016. A higher total social cost of carbon would increase the extra cost of imports but would require similar adjustments to the GB price, offsetting the change.

[30] A regression of DAM price on demand less wind for 2015 gives €1.19 +/− €0.02/GW, slightly less (€1.11 +/− €0.02/GW) for a regression of DAM price on demand less wind and less interconnectors.

[31] Guo et al. (2019) uses econometrics to provide a more precise estimate on

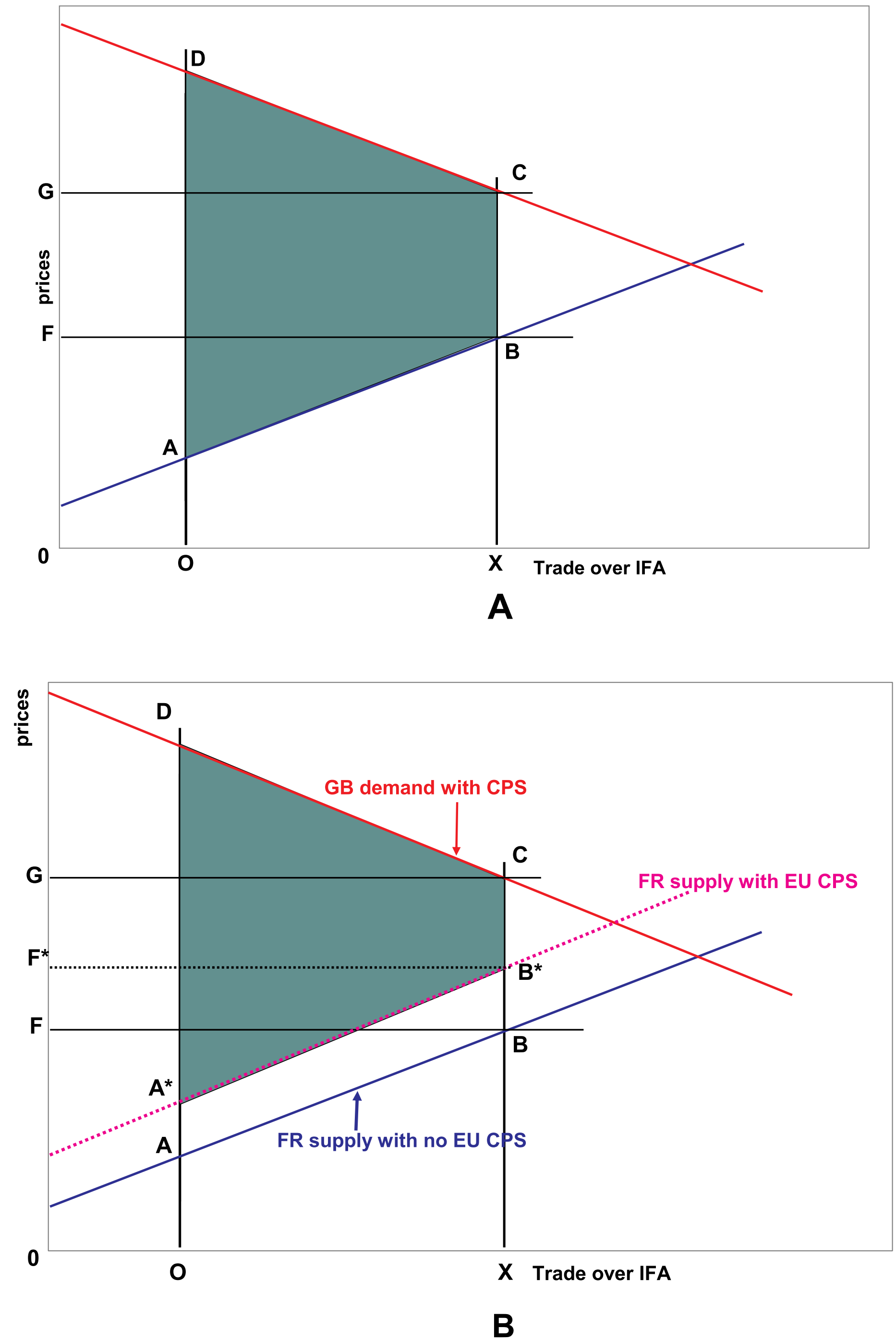

Fig. 8. Trade over interconnectors at market prices (left panel) and with (right) EU CPS.

infra-marginal surplus is thus €25 m./yr.

Fig. 8b shows the potential distortion that arises when GB imposes a carbon tax (the CPS) while its trading partner does not. If this distortion were removed by the EU imposing the correct CPS, then the French supply schedule would shift up from AB to A*B*. The French price would rise to F* and the value of trade would fall to (F*G)*OX and the social value would be less than the market value (at distorted prices) plus infra-marginal surpluses by the area AA*B*B, leaving the shaded area as the correct social value of the interconnector. Guo et al. (2019) estimate that by removing the British CPS (or equivalently, the EU implementing the same CPS as GB), the market distortion from unilateral carbon tax would be eliminated, as would the €30 m./yr deadweight loss.

If the French price is set in Germany, then based on the German marginal share of energy generation in 2016 (from Castagneto-Gissey et al., 2018), and using the carbon intensity provided by Grid Watch,[32] an EU-wide CPS would raise the French price by an average of €7.38/MWh, slightly lower than an increase of €9.41/MWh for GB prices (using the same data source). The average volume traded in 2016 was

(footnote continued)
the infra-marginal surplus, which turns out to be very close to our brief estimates in this paper.

[32] http://gridwatch.co.uk/co2-emissions.

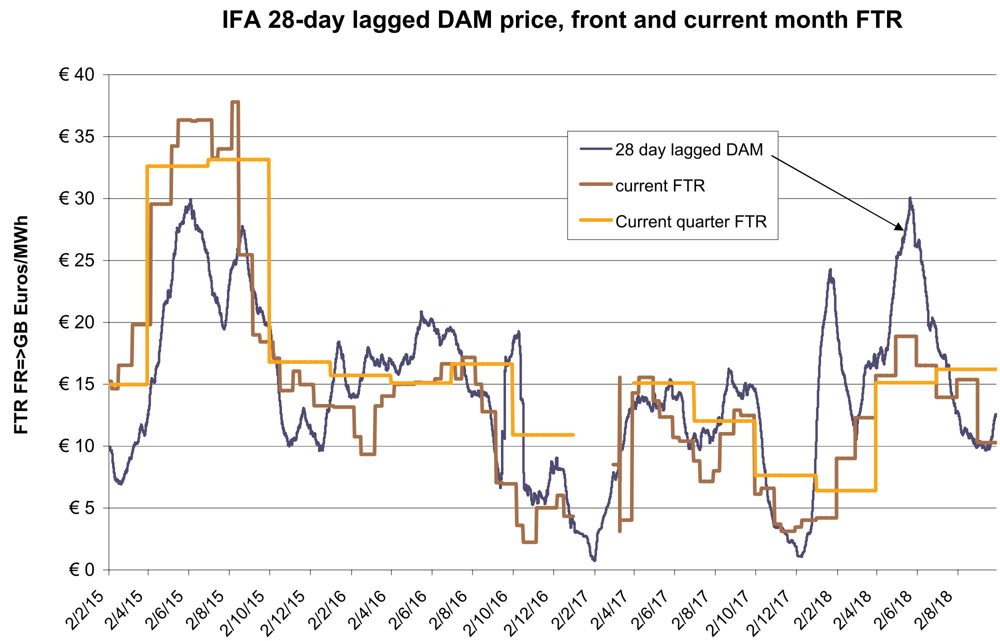

Fig. 9. FTRs and lagged DAM price differences over IFA. Note: Contracts are traded on typically two days each month.

1147 MW, the effect of the GB CPS alone is to increase congestion income by €95 million, which is paid by the GB citizens and equally split by both RTE and the National Grid. If an EU-wide CPS is implemented, congestion income would only rise by €21 million, a reduction of €74 million.

9. Forward trading over interconnectors

Forward trading predates market coupling. Before 2014 forward contracts were for rather illiquid Physical Transmission Rights (PTRs). After coupling, more liquid Financial Transmission Rights (FTRs) replaced PTRs as effectively CfDs, as shown in Fig. 9. If the UK were no longer able to access EUPHEMIA after leaving the EU, then forward trading would likely revert to PTRs. This section examines what other contract markets might be able to replicate the FTRs, reducing the cost of uncoupling.

FTRs are auctioned ahead of delivery for periods of years, quarters, months and weeks at various dates during the year. For IFA,[33] there are two auctions for annual contracts held in the middle of the first and third week of July the year before, and a third one in the middle of August. There are typically two auctions for the month ahead, for the quarter ahead held one or two months before, for the summer ahead held in Jan and Feb, and for the winter ahead in April and May. For IFA 93% of the available 2000 MW are sold forward, of which half is for the calendar year.

FTR auction clearing prices for IFA and Britned are publicly available.[34] Fig. 9 shows the lagged 28-day moving average of the DAM GB – FR price differences and the FTRs for the current month (sold the month before) and the current quarter.[35] As FTRs are options only exercised if profitable, they are compared with the moving average of the positive values of hourly price differences.

In 2015, the FTRs sold at a premium to the underlying product (the DAM price difference) but thereafter they appear to have converged, with if anything some undershooting. The FTRs give the right to import but losses mean that they are actually worth somewhat less than their price, which ignores losses.[36] Appendix A gives tables showing the auction outcomes for both IFA and BritNed, showing the ratio of the latest (and presumably most accurate) auction price to the outturn. Thus for the 2015 monthly auctions the average ratio for IFA is 1.35 and for BritNed is 1.36 with coefficients of variation (CV) of 22% and 18%, whereas the hourly CV over the whole year for price differences across IFA is 83% (81% for Britned). The 2015 annual and quarterly auctions show a larger ratio or risk premium, as the hedge is taken under greater uncertainty about the future market conditions. Forward trading over the two interconnectors seems to be remarkably similar in risk aversion. However, by 2016 it would be hard to reject the hypothesis that the quarterly auctions exhibit no risk premium.

9.1. Comparing FTRs and hedging on local power exchanges

It is also possible to buy power forward in both France and GB (and NL, but we focus on France and GB) and replicate an FTR with CfDs. Indeed, Nordpool used CfDs to hedge zonal price differences rather than FTRs (Lundgren and Forsberg, 2016). Fig. 10 compares the two instruments for 2016–18 for selling from France to GB against the DAM monthly average for the delivery month. The auctioned FTRs are only issued at two points in the month (assumed here to be the first and second or third Thursday), hence FTR I and FTR II, whereas the CfDs for the named month are traded actively on workdays for several months ahead (as shown in Appendix Figure A1). Here the CfD price differences on the dates of the FTR auction are shown as CfD I and CfD II. There appears to be considerable convergence after the first year (2015) except for December 2016, when French nuclear stations were off-line. Even if uncoupling meant FTRs reverting to PTRs, CfD markets in neighbouring countries should offer additional and rather complete hedging, reducing the damage of uncoupling.

[33] See http://ifa1interconnector.com/media/1041/ifa-long-term-auction-timetable-2018.pdf.

[34] FTR auction clearing prices for IFA are available at https://damasifa.unicorn.eu/Long-term_Auction_Statistics.asp and for BritNed at https://www.britned.com/participants-portal/explicit-auctions/.

[35] The FTRs were also compared for the month in which they were traded – i.e. DAM price differences for January 2015 were compared to the FTRs for February 2015 that were being auctioned in January 2015, but these fail to match turning points in the DAM price differences, so the FTRs seem to have better predictive value and are compared with the delivery month.

[36] Each market operator decides how to treat losses. In the SEM FTR pay-outs are adjusted for transmission losses over the interconnector.

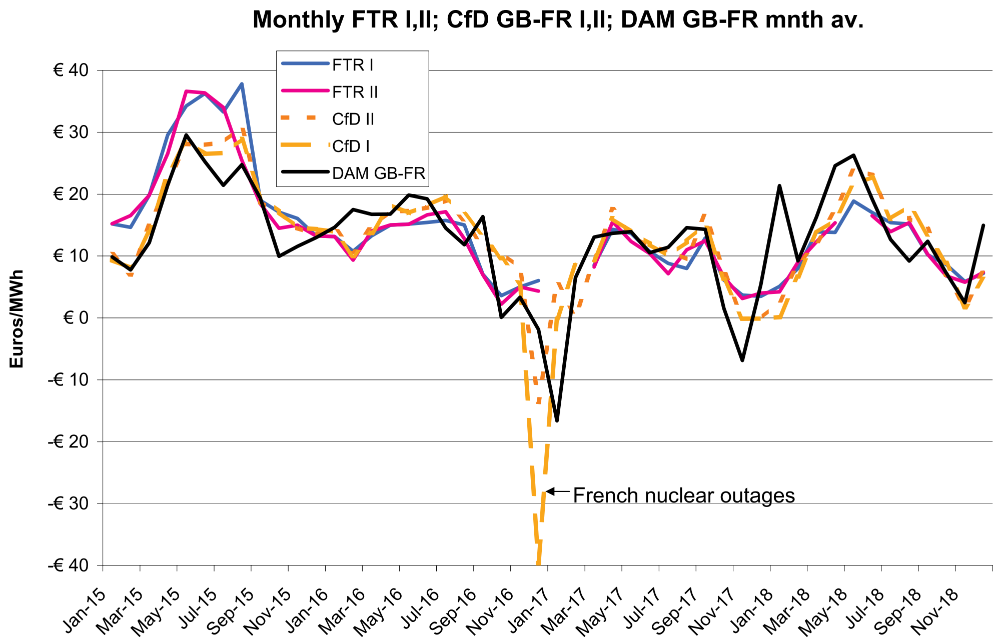

Fig. 10. Comparison between hedging across IFA using local power exchanges and FTRs compared to monthly DAM price differences for the delivery month. Source: Bloomberg and ENTSO-E.

10. Conclusions and policy implications

We explored the efficiency of trading on the Day Ahead Market (DAM) auction platform before and after market coupling, and established that market coupling has indeed created efficient trading at the day-ahead stage on IFA and BritNed. The Single Electricity Market (SEM) of the island of Ireland was finally coupled on 1 October 2018 and since then the DAM auctions have efficiently used the interconnectors.[37] Before that, it was trading very inefficiently, with flows in the wrong direction almost half the time, and losses that the regulators estimated for 2010 as €30 million/yr. ACER claimed even larger losses. The arbitrage revenue for trading capacity on the DAMs for IFA and BritNed averages about €125 million/GWyr, or €375 million/yr for both.

The policy of coupling markets has therefore been successful, increasing the urgency of coupling balancing markets. Further investment in interconnectors is likely to be socially desirable, particularly with increased renewables penetration, subject to harmonising the treatment of carbon taxes across the EU.

Trading after the DAM closes allows adjustments to be made, and GB often revises its off-peak position to secure flexibility when fossil generation is at minimum load and pumping at maximum, so reducing imports is an effective balancing option. The value of intraday trading is however modest at €10 m/yr or about 3–4%, in line with earlier estimates for the EU (Newbery et al., 2016). The total commercial value including capacity market revenues, forward trading and other ancillary services is considerably higher than the DAM arbitrage values at about €500 million/yr for both or nearly €170/kWyr.

There are active forward markets for annual, seasonal, quarterly and monthly Financial Transmission Rights (FTRs). The 2015 FTR auctions traded at a substantial premium (about 35%) to the cost of securing an equivalent baseload supply in the DAM, but this premium almost disappeared in the following years, consistent with growing familiarity with, and liquidity of, the FTR auctions. Hedging using CfDs on local power exchanges appears to offer as good a hedge as FTRs, again after the first year (2015), although local CfDs appear more sensitive to news, e.g. about scheduled power outages, that are alleviated in the DAM auctions as wider areas are coupled.

The commercial value of IFA and BritNed together is substantial at about €500 million/yr, including contributions to security of supply. The social value is higher by about €25 million/yr of avoided inframarginal generation cost. The British carbon price floor transfers €65 million/yr to the foreign share of IFA and BritNed. It also adds distortionary costs when trade flows change. The policy implication is that the EU should implement a carbon price floor at least in the electricity sector to remove this distortion while giving more stable investment signals for decarbonising power (Newbery et al., 2018).

As of July 2018, the future relationship of GB with the European Union is unclear. A worst-case scenario might lead to uncoupling and even tariffs to use the EU transmission system (DG ENER, 2018). This could lead to a loss of much of the coupling benefit, although trading CfDs on neighbouring power exchanges supplemented by PTRs (as used before coupling) might continue to deliver most of the trading benefits. There would seem little to prevent setting up a similar DAM and IDM in GB for trading over the interconnectors, although sacrificing some gains from a pan-European simultaneous auction. It might even allow possibly better auction bid formats that better reflect the operating realities.[38] Enhancing liquidity and transparency of such markets is clearly

[37] See the *Single Electricity Market Performance 1 Oct 2018 – 31 Jan 2019* at https://www.semcommittee.com/sites/semc/files/media-files/MMU%20public%20report%20Jan%2019.pdf.

[38] EUPHEMIA is challenged if more than a few units submit complex and block bids reflecting start-up costs and minimum up and down times.

desirable whatever happens to the UK's relationship with the EU.

Acknowledgements

We gratefully acknowledge research support from InnovateUK and the UK Engineering and Physical Sciences Research Council (EPSRC) via the 'Prospering from the Energy Revolution" Industrial Strategy Challenge Fund', for the project "The value of Interconnection in a Changing EU Electricity system" (ICE) (EP/R021333/1). We are indebted to several referees for helpful comments.

Data Availability

Data relating to interconnector prices and flows are available from the ENTSO-E transparency platform at https://transparency.entsoe.eu/. Other data is given in the appendices or listed under figures.

Appendix A. FTR Auction data

Table A1 compares the efficacy of hedging using the last price available of CfDs on power exchanges and FTRs secured at the latest auction in the month.

Table A1
Comparison of FTRs, DAM options and CfDs (IFA, 2015–18). In Table A1, CfD last is the last day's closing price for GB – FR contracts, and CfD I and II align with the auction dates for the FTRs. FTRs have the advantage of being options not obligations while CfDs can be retraded repeatedly. Auctions are normally considered to aggregate information better than continuous trading at any moment, but the latter can take account of more information as it unfolds.

Monthly FR = > GB	FTR I	FTR II	DAM option	CfD last	CfD I	CfD II
Jan-15	€ 15.20	€ 15.23	€ 9.87	€ 15.15	€ 9.36	€ 10.28
Feb-15	€ 14.64	€ 16.53	€ 7.74	€ 5.49	€ 8.06	€ 7.03
Mar-15	€ 19.81	*€ 19.81*	€ 12.15	€ 14.92	€ 13.77	€ 14.86
Apr-15	€ 29.55	€ 26.54	€ 21.45	€ 19.10	€ 23.24	€ 21.85
May-15	€ 34.25	€ 36.60	€ 29.55	€ 28.66	€ 28.55	€ 28.09
Jun-15	€ 36.25	€ 36.34	€ 25.24	€ 28.02	€ 26.48	€ 27.95
Jul-15	€ 33.26	€ 34.00	€ 21.43	€ 20.48	€ 26.66	€ 28.36
Aug-15	€ 37.80	€ 25.45	€ 24.75	€ 28.87	€ 28.92	€ 30.83
Sep-15	€ 18.98	€ 18.42	€ 19.33	€ 19.36	€ 19.66	€ 18.74
Oct-15	€ 17.10	€ 14.49	€ 9.94	€ 15.62	€ 17.14	€ 17.16
Nov-15	€ 16.05	€ 14.97	€ 11.56	€ 12.21	€ 14.61	€ 14.54
Dec-15	€ 13.26	*€ 13.26*	€ 12.95	€ 16.06	€ 14.33	€ 13.46
Jan-16	€ 13.15	*€ 13.15*	€ 14.64	€ 11.49	€ 13.93	€ 14.47
Feb-16	€ 10.76	€ 9.34	€ 17.49	€ 11.11	€ 10.01	€ 10.72
Mar-16	€ 13.25	€ 14.05	€ 16.74	€ 15.98	€ 13.71	€ 14.72
Apr-16	€ 14.99	€ 15.01	€ 16.76	€ 17.82	€ 18.28	€ 17.29
May-16	€ 15.15	€ 15.12	€ 19.83	€ 17.97	€ 16.90	€ 17.25
Jun-16	€ 15.43	€ 16.65	€ 19.23	€ 19.72	€ 18.10	€ 17.84
Jul-16	€ 15.75	€ 17.16	€ 14.52	€ 16.94	€ 19.66	€ 19.00
Aug-16	€ 15.01	€ 12.79	€ 11.83	€ 16.06	€ 16.72	€ 15.77
Sep-16	€ 7.05	€ 6.95	€ 16.36	€ 6.91	€ 13.47	€ 11.52
Oct-16	€ 3.60	€ 2.23	€ 0.09	€ 16.52	€ 9.67	€ 10.55
Nov-16	€ 5.01	€ 5.01	€ 3.33	-€ 4.88	€ 5.68	€ 8.04
Dec-16	€ 6.03	€ 4.34	-€ 1.88	-€ 10.21	-€ 39.66	-€ 13.59
Jan-17			-€ 16.63	€ 0.57	-€ 0.18	€ 5.82
Feb-17			€ 6.50	€ 1.12	€ 8.50	€ 0.23
Mar-17	€ 8.51	€ 8.21	€ 13.04	€ 10.89	€ 9.36	€ 9.38
Apr-17	€ 14.30	€ 15.55	€ 13.65	€ 16.63	€ 16.09	€ 17.54
May-17	€ 13.66	€ 12.36	€ 13.93	€ 14.89	€ 13.86	€ 13.28
Jun-17	€ 10.70	€ 10.40	€ 10.53	€ 10.35	€ 11.94	€ 11.43
Jul-17	€ 8.81	€ 7.15	€ 11.42	€ 13.27	€ 9.98	€ 10.85
Aug-17	€ 8.00	€ 11.00	€ 14.58	€ 15.33	€ 12.35	€ 9.41
Sep-17	€ 12.90	€ 12.47	€ 14.32	€ 15.87	€ 15.24	€ 16.76
Oct-17	€ 6.12	€ 6.60	€ 1.56	€ 2.21	€ 6.28	€ 7.65
Nov-17	€ 3.70	€ 3.12	-€ 6.89	-€ 0.14	-€ 0.12	-€ 0.12
Dec-17	€ 3.47	€ 4.02	€ 5.40	-€ 0.14	-€ 0.12	-€ 0.13
Jan-18	€ 5.08	€ 4.21	€ 21.36	€ 3.41	€ 0.15	€ 2.61
Feb-18	€ 7.98	€ 9.01	€ 9.21	€ 8.24	€ 6.67	€ 8.71
Mar-18	€ 13.91	€ 12.30	€ 16.29	€ 16.11	€ 13.73	€ 12.17
Apr-18	€ 13.81	€ 15.37	€ 24.59	€ 18.59	€ 15.90	€ 17.29
May-18	€ 18.87		€ 26.28	€ 28.64	€ 21.56	€ 23.88
Jun-18	€ 17.03	€ 16.51	€ 19.22	€ 19.19	€ 22.76	€ 23.05
Jul-18	€ 15.39	€ 13.94	€ 12.68	€ 12.05	€ 15.98	€ 15.98
Aug-18	€ 15.17	€ 15.38	€ 9.20	€ 53.50	€ 18.13	€ 16.14
Sep-18	€ 10.17	€ 10.28	€ 12.38	€ 10.38	€ 13.50	€ 14.33
Oct-18	€ 8.63	€ 6.78	€ 7.24	€ 7.25	€ 8.89	€ 6.94
Nov-18	€ 5.88	€ 5.77	€ 2.44	€ 3.98	€ 1.72	€ 1.77
Dec-18	€ 7.20	€ 7.38	€ 14.94	€ 9.66	€ 6.27	€ 7.42

Table A2
Monthly Auctions FR or NL to GB and DAM averages [GB-FR/NL] +. Note: [GB-NL] + and DAM option mean the positive price differences, Max(DAMGB-DAMFR,0), lagged average over 28 days or 672 h.

Month	IFA				BritNed			
	Auction I	Auction II	DAM option	Ratio II/Actual	Month	Auction	DAM option	Ratio
Jan	€ 15.20	€ 15.23	€ 10.09	1.51	**Apr-15**	€ 24.42	€ 18.05	1.35
Feb	€ 14.64	€ 16.53	€ 8.10	2.04	**May-15**	€ 28.17	€ 17.42	1.62
Mar	€ 19.81		€ 12.11	1.64	**Jun-15**	€ 26.60	€ 17.36	1.53
Apr	€ 29.55	€ 26.54	€ 21.44	1.24	**Jul-15**	€ 28.29	€ 16.76	1.69
May	€ 34.25	€ 36.60	€ 29.55	1.24	**Aug-15**	€ 28.01	€ 16.69	1.68
Jun	€ 36.25	€ 36.34	€ 25.25	1.44	**Sep-15**	€ 17.21	€ 15.67	1.10
Jul	€ 33.26	€ 34.00	€ 24.60	1.38	**Oct-15**	€ 17.03	€ 12.24	1.39
Aug	€ 37.80	€ 25.45	€ 24.75	1.03	**Nov-15**	€ 18.84	€ 13.69	1.38
Sep	€ 18.98	€ 18.42	€ 19.32	0.95	**Dec-15**	€ 19.25	€ 13.25	1.45
Oct	€ 17.10	€ 14.49	€ 9.94	1.46	**Jan-16**	€ 19.66	€ 16.28	1.21
Nov	€ 16.05	€ 14.97	€ 11.55	1.30	**Feb-16**	€ 17.07	€ 17.83	0.96
Dec	€ 13.26		€ 12.92	1.03	**Mar-16**	€ 16.39	€ 16.71	0.98

Table A3
Quarterly and annual 2015 auctions FR/NL to GB and DAM averages [GB-FR/NL]+. Note: Auction I* for BritNed is average of previous 8 auctions, ratio is last auction to DAM. Missing values denote unavailable results.

Quarterly	IFA				BritNed			
	Q1 2015	Q2	Q3	Q4	Q1 2015	Q2	Q3	Q4
Auction I	€ 16.15	€ 34.36	€ 35.58	€ 15.90	€ 20.22	€ 25.15	€ 28.65	€ 27.95
Auction II	€ 14.98	€ 32.62	€ 33.15	€ 16.80				
Actual/option	€ 10.25	€ 25.48	€ 21.88	€ 11.84		€ 19.03	€ 17.49	€ 14.27
Ratio II/Actual	1.46	1.28	1.52	1.42		1.32	1.64	1.96
Annual	**CAL 2015**		**FY 2015–16**		**CAL 2015**		**FY 2015–16**	
Auction I*	€ 25.23		€ 24.95		€ 20.98			
Auction II	€ 24.80		€ 26.38		€ 23.86			
Actual	€ 17.38				€ 15.79			
Ratio II/Actual	1.43				1.51			

Table A3 similarly shows the quarterly auctions and the annual auctions (two for IFA, 9 for BritNed), and both tables show the ratio of the latest (and presumably most accurate) auction price to the outturn.

Table A4
Auction and DAM option results 2016.

Q1 2016	IFA auction	GB-FR DAM option	ratio	BN auction	GB-NL DAM option	ratio
	€ 15.71	€ 16.25	0.97	€ 18.61	€ 17.26	1.08
Q2	€ 15.10	€ 18.67	0.81	€ 13.75	€ 16.41	0.84
Q3	€ 16.63	€ 14.69	1.13	€ 12.73	€ 14.93	0.85
Q4	€ 10.90	€ 6.80	1.60	€ 18.74	€ 19.56	0.96
Average	€ 14.59	€ 14.10	1.03	€ 15.96	€ 17.04	0.94
Annual	€ 17.00	€ 13.97	1.22	€ 17.81	€ 17.00	1.05

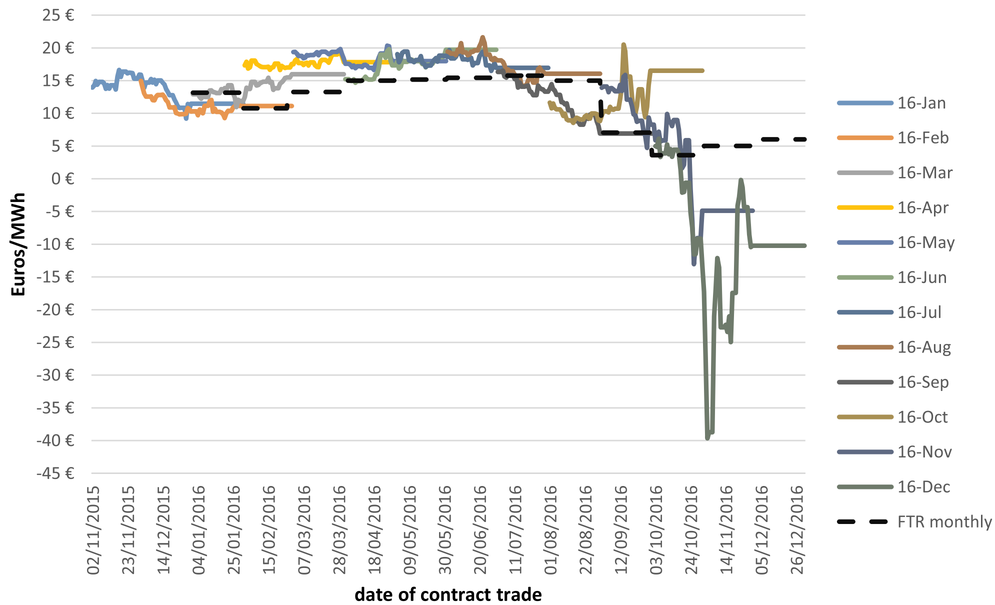

Fig. A1. Comparison between hedging across IFA using local power exchanges and FTRs month. Source: Bloomberg and ENTSO-E.

Appendix B. ENTSO-E Data Description[39]

1 Day-ahead prices

For every market time unit the day-ahead prices in each bidding zone (Currency/MWh).
Note: In case of implicit allocation, Gate closure time of the day-ahead market shall be understood as the output time of the matching algorithms.
Primary owner of the data: Power Exchanges or TSOs.

2 Total scheduled commercial exchanges

Means aggregated schedules, in MW per direction and border (E.g.: between two bidding zones) and per market time unit for all previous time horizons (yearly, monthly, quarterly, weekly, daily, intra-Day) corresponding to explicit allocations after each nominations process and implicit allocation.

The value published for the day ahead time horizon consists of commercial exchanges in aggregated form from the following allocations: yearly, monthly, quarterly, weekly and daily.

The value published for the intraday time horizon consists of commercial exchanges in aggregated form from the following allocations: yearly, monthly, and quarterly, weekly, daily and intraday.

Time interval is one day and resolution is market time unit.

The abovementioned values will be published after the day ahead cut off time and, if applicable, will be updated no later than 2 h after each intra-day nomination process.

3 Cross Border Physical flow

Defined as the measured real flow of energy between neighbouring bidding zones on the cross borders. Physical flows between bidding zones per market time unit as closely as possible to real time and at the latest H + 1 after the end of the application period.

Specification of calculation: Average values (in MW); netted values.

4 Total Nominated Capacity

For every market time unit and per direction between bidding zones the total capacity nominated (MW) from capacity allocated via explicit allocations only.

Total capacity nominated means aggregated capacity nominated by market participants from time horizons (yearly, monthly, quarterly, weekly, daily, intra-day) corresponding to explicit allocations, agreed between the TSOs and confirmed to the market.

The total capacity nominated for submission (and publication) is the amount of nominated capacity in MW per border and direction (E.g.: between two bidding zones) and per market time unit.

The value published for the long-term time horizons consists of nominations from the following applicable allocations: yearly, quarterly, monthly and weekly.

The value published for the **day ahead time** horizon consists of nominations from the following allocations: yearly, quarterly, monthly, weekly and daily.

[39] From https://transparency.entsoe.eu/.

The value published for the Intraday time horizon consists of nominations from the following allocations: yearly, quarterly, monthly, weekly, daily and intraday.

The abovementioned values will be updated after each nomination process if values are confirmed by TSOs.

Primary owner of the data: Transmission Capacity Allocator/TSO.

5 Daily Flow Based Implicit Allocations - Congestion Income

In case of implicit allocations, for every market time unit the net positions of each bidding zone (MW) and the congestion income (in Currency) per border between bidding zones. The information shall be published no later than 1 h after each capacity allocation.

Detailed description:

In case of implicit allocations:

1. Net position for each bidding zone per market time unit with indicator whether the value represents import or export.
2. The congestion income per market time unit, per border between bidding zones except for regions with flow-based calculation method where the congestion income is available per bidding zone.

Primary owner of the data: Congestion revenues are calculated by the Central Counter Party or shipping agent.

In more detail: "For the Day-Ahead Market Time-frame the Congestion Income generated on a Bidding Zone border shall be calculated as the absolute values of the product of the Commercial Flow times the Market Spread. For the Intraday Market Time-Frame the Congestion Income shall be calculated as the sum of all revenues from the Capacity Allocation per MTU." (ENTSO-E, 2016a).

The forecasted NTC (MW) per direction between bidding zones, including technical profiles. only in NTC allocation method.

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