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The UK left the EU Integrated Electricity Market on 31/12/20 and with it access to Single Day Ahead Coupling that clears local and cross-border trades jointly – interconnectors are implicitly auctioned. The new the Trade and Cooperation Agreement requires a replacement "Multi-region loose volume coupling" to be introduced before April 2022. Until then, interconnector capacity is allocated by an explicit day ahead auction before the EU auction with nomination after the EU results are known. The paper measures the risks posed by taking positions in each market separately and the resulting costs of uncoupling of GB's interconnector trade. It compares four forecasts of price differences under two sequencing of markets and explicit auction, determining traders' risk premia for each. The current timing leads to lower mistakes on the direction of flows, although higher profit volatility, arguing to retain the current timing. Competitive traders locking in their positions after the explicit auction (overstating costs as subsequent trading out of unprofitable positions is ignored) limit the total loss of interconnector revenue from uncoupling to €31 million/yr., and the social cost of uncoupling is €28 million/yr., considerably below earlier estimates in the literature.

Reference Details

CWPE	2118
Published	3 March 2021
Key Words	Electricity trading, Market coupling, auctions, price forecasting
JEL Codes	F14, F15, Q47, Q48, L94
Website	www.econ.cam.ac.uk/cwpe

UNIVERSITY OF CAMBRIDGE | Energy Policy Research Group

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Bowei Guo[a,b] and David Newbery[a]

EPRG Working Paper 2102

Cambridge Working Paper in Economics 2118

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Publication March 2021

Financial Support 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).

The cost of uncoupling GB interconnectors

Bowei Guo[1] and David Newbery[2]
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5 February 2021

Abstract
The UK left the EU Integrated Electricity Market on 31/12/20 and with it access to Day Ahead implicit auctions. Before new "Multi-region loose volume coupling" are designed and introduced, trade over interconnectors are replaced by an explicit day ahead auction before the EU auction with nomination after the EU results are known. We ask what this implies for the efficiency of GB's interconnector trade. The paper compares four forecasts of price differences under two sequencing of markets and auction, and determines traders' risk premia for each, concluding that reversing the current timing and accelerating the move to volume coupling would be highly desirable. Under the determined risk premia, we estimate the total loss in the congestion revenue from uncoupling is €38 million/yr, while the social cost of uncoupling is €34 million/yr.

1. Introduction

On January 1st, the UK ended the transition period of exiting the European Union and started trading under the new Free Trade Agreement (FTA,[3] the *Trade and Cooperation Agreement*).[4] Until that date, Great Britain traded electricity under the EU Integrated Electricity Market (IEM) arrangements that were designed to facilitate electricity trade over interconnectors joining different countries by reducing risk. Northern Ireland (NI) and the Republic of Ireland (RoI) continue trading electricity in the integrated Single Electricity Market. NI is more closely aligned under its *Withdrawal Agreement* with the EU Member State, the RoI, and is treated as such under the new FTA. The consequences of Brexit on the British electricity sector are well documented (e.g. Aurora Energy Research, 2016; Vivid Economics; Froggatt et al., 2017; Mathieu et al., 2018; Pollitt, 2017; Pollitt and Chyong, 2017).

This paper estimates quantitatively the impact of the change in trading arrangements over interconnectors to the Continent on the efficiency of trading, the revenues of their owners and of traders, and specifically, the social cost of uncoupling. By comparing different possible timings of auctions for interconnector capacity and domestic demand the paper considers whether relatively rapid reforms to the order of these markets would improve

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[3] A list of abbreviations is given after the reference section
[4] https://www.gov.uk/government/publications/agreements-reached-between-the-united-kingdom-of-great-britain-and-northern-ireland-and-the-european-union

efficiency. There is a deadline of March 2022 to implement new "loose coupling" trading arrangements, and this paper argues for additional changes to improve their efficiency.

While GB remained in the IEM the interconnectors were subject to the Single Day Ahead Coupling (SDAC) arrangements. These are governed by Article 37(5) of Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing guidelines on Capacity Allocation and Congestion Management ('CACM Regulation', see ENTSO-E 2019). Under SDAC at the day-ahead stage all coupled members of the IEM submit bids and offers to the EUPHEMIA EU-wide Day Ahead Market (DAM) auction platform. The EUPHEMIA algorithm finds the consumer and producer surplus maximising solution for generation and demand offered into the auction, subject to meeting transmission constraints, including the capacity of interconnectors. If in the solution an interconnector is unconstrained, prices at each end will be the same (adjusted for any losses over the interconnector). If the interconnector capacity constraint binds, prices will diverge, and the price difference times the volume flowed will be the congestion revenue received by the interconnector owners.

Guo and Newbery (2020) demonstrated that the GB Carbon Price Support (CPS, an extra carbon tax on generation fuels) distorted trade over interconnectors, and calculated the impacts on prices in GB and its neighbours, as well as the deadweight loss and the impact on interconnector revenue. This paper ignores the complexity of asymmetric carbon taxation, and looks forward to a time when carbon prices are aligned across trading countries, in order to focus just on estimating the cost of uncoupling. It does, however, employ the same methodology to estimate the social cost of uncoupling.

Newbery et al. (2016) demonstrated that SDAC delivered substantial financial benefits of about €1 billion to the EU as a whole (substantially more if balancing markets were integrated as well). Uncoupling the UK from the EU is therefore potentially costly, perhaps €60 million/yr, assuming the same loss per MWh as for the countries in Newbery et al. (2016, Table 1). Lockwood et al. (2017) estimated the economic benefit of GB integrating with the Continent to be up to £1bn/year, representing the economic loss when the market integration between the two was undone. Geske et al. (2020) estimated that a hard Elexcit (i.e. uncoupling with no substitute trading arrangements) might eventually cost up to €300m/yr for Great Britain (with producers gaining and consumers losing €860/yr).[5] These earlier estimates suggest that the costs of uncoupling can be substantial, but fortunately the FTA that the UK has negotiated with the EU, when implemented, should substantially reduce these costs. This paper estimates the immediate costs for one interconnector (that to France, Interconnexion France Angleterre - IFA) and assesses possible improvements to the final implementation of the FTA. Appendix A gives results for the other interconnectors to France and the Netherlands. The aim is to err on the high side of the possible costs, and demonstrate that they are considerably lower than some of the earlier more doom-laden predictions.

Under the new FTA, the System Operators (SOs) in GB and those in countries interconnected to GB (France, Netherlands, France and the SEM) need to develop new trading arrangements based on "Multi-region loose volume coupling", with a timetable of

[5] The benefit of market integration in other electricity markets can also be substantial, as seen in the PJM's market area (Mansur and White, 2012), between Denmark and Germany (Meeus, 2011), and between GB and the Irish Single Electricity Market (SEM, 2011).

entry into operation within 15 months (see Appendix B). Meanwhile the default position is as set out in various announcements by the Government and regulators, discussed below. Meeus and Schittekatte (2020) describe the evolution and various forms of market coupling within the EU that put these alternatives in context.

Market coupling is important not just for ensuring efficient use of the interconnectors, but also in facilitating the creation of contracts to reduce the risk of trading. Generators need to sell their output on the most favourable terms, balancing risk and reward. Their risks are physical (outages, or for variable renewables, resource – wind or sun – conditions) and financial (prices of inputs and outputs). Physical risks can be insured against (for plant) and/or predicted and self-hedged. Financial risks can similarly be hedged on various markets and/or self-hedged by signing up customers and integrating into retailing.

The question addressed in this paper is how hedging is affected by trading over interconnectors with and without market coupling and what that implies for efficiency, incomes and social benefits. Section 2 sets out the methods for estimating these impacts. Section 3 describes the ways of reducing risk, section 4 describes the consequences of Brexit for the interim electricity trading arrangements, section 5 sets out the methods, data sources and results for estimating the cost of risk, and section 6 examines the case for strengthening the FTA's proposed 'Multi-region loose volume coupling' to include firm Financial Transmission Rights. Section 7 concludes with policy recommendations.

2. The impact on uncoupling on revenues and social cost

Provided all externalities are internalised through charges and subsidies (as was intended for carbon under the EU ETS and the *Renewables Directives*) and if electricity wholesale markets are workably competitive (as they are in GB), then market prices would correctly measure the social cost of generation. We make this assumption, recognising that further corrections might be needed, as set out in Guo and Newbery (2020). Assuming, as is standard, that in the short-run demand is inelastic, the impact of uncoupling is to reduce the willingness of traders to pay for interconnector capacity and as a result to nominate lower amounts to trade. Lower prices for capacity and lower trade volumes reduce interconnector congestion revenue, as well as reducing the social benefits of trading.

The social cost of uncoupling is the increase in generation cost caused by reducing the extent to which exports from the lower cost country are reduced. If the coupled price differences in any hour were Δp, and after uncoupling in that hour are ΔP, and if the reduction in trade is Δm, the increase in social cost is $\frac{1}{2}(\Delta p + \Delta P)\Delta m$, where Δm may have to take account of a change in direction of trade. Δp is observed, and ΔP can be estimated using the methodology and results of Guo and Newbery (2020). The key element in these calculations is to estimate Δm by examining the response of traders to uncoupling and its subsequent impact on prices and congestion revenues.

The problem of forecasting the optimal trading position is complicated by the existence of Flows Against Price Difference (FAPD), i.e. cases where the traders make an incorrect judgement of the sign of the price difference and hence on the direction of trade. Consider a simple example in which traders make on average correct forecasts of price differences, and trade on the basis of unbiased forecast price differences. If the interconnector has capacity C = 2 GW, with expected price differences, d, (GB-FR) of €4/, €3, €1, -€4, (all per MW capacity for an hour, i.e. per MWh), all equally probable, The expected price difference, Ed = €1/MWh. If traders also nominate on the basis that imports are always profitable, they might expect to receive in the four states €8k, €6k, €2k and -€8k, averaging to €2k. This is what they would have been willing to bid, Ed.EC = €2k.

If they believe that they can choose not to nominate unprofitable trades the option to import is worth €2/MWh and their expected revenues in the four states is be €8k, €6k, €2k and €0, on average €4k. Clearly if they pay that amount and then fail to nominate in the correct direction they earn €2k but have paid €4k and make a loss. In this paper, erring on the side of overestimating costs, the assumption is that actual nominations are based on the original forecasts of price differences. This will influence the value they attach to and are willing to bid for capacity, which we address by adding a "risk" premium to their unbiased price forecast. In practice sometimes it will be less costly not to nominate unprofitable trades, and even if they do, there are further opportunities to unwind unprofitable positions in intra-day markets up to real time dispatch. However, compared to the situation under coupling, the outcome would have been €8k, €6k, €2k and +€8k with an average of €6k, three times their average outcome from always nominating to meet buy and sell commitments. Again, the social cost of uncoupling will tend to be overstated.

3. Risk, contracting and hedging

The cost of the risks facing agents will depend very much on their portfolio of assets, commitments, and financial resources, with the larger and better endowed better able to take a riskier position, or requiring a lower risk premium to accept that risk. It may be helpful to consider three types of agents – a generator without any captive customers (i.e. not an integrated utility); a retailer without any generation assets, and a trader with no physical assets but a large and diverse trading portfolio. Each will face different risks, but generator and retailer risks are complementary in that high prices benefit generators but harm retailers (at least to the extent that they have signed a contract to supply customers at a fixed price for a period), while conversely low prices benefit retailers but harm generators. This risk complementarity provides the motivation to sign contracts.

Traders typically do not have offsetting risks (although many act as the trading arm of often vertically integrated utilities) but they specialise in expertise, volume, financial strength and the ability to diversify across commodity classes and countries. Given that electricity prices typically follow gas prices, electricity price risk can be reasonably well hedged by a gas contract. When carbon prices become significant, a combined gas (or coal) and carbon contract improves the hedge (Guo and Castagneto Gissey, 2019).

The classic contract to handle price risk is the Contract for Difference (CfD), characterised by a quantity, M, a strike price, s, and the reference price p, (e.g. the Day Ahead Market – DAM – price). Suppose that s is such that each party is content to buy/sell the contract without any additional side payment. The seller of the CfD then receives (s-p).M and the buyer pays (s-p).M, which can be either positive or negative. In effect the seller has sold forward M at the strike price s, which the buyer has bought, but each transacts in the relevant market at price p for the M. A two-sided CfD is an obligation, with the holder obligated to pay the other party when it is in the money for the other party. In contrast, an option allows the holder to receive payments when in the money but to avoid payments in adverse states.

One-sided CfDs have the form of an option, and can either pay out if they market price rises above a strike price, or if it falls below a strike price. The one-way up-side CfD, often termed a Reliability Option, is a way of hedging consumers against price spikes, and auctioning them can provide a capacity payment, paying generators to deliver in stress periods when the price spikes, e.g. in the Single Electricity Market (SEM) of the island of Ireland.

3.1 Trading and hedging over interconnectors

Single Day Ahead Coupling solved one critical problem – that of inefficient trading on interconnectors, but did not in itself solve the other problem of trading across borders, that of price risk between different countries. However, integrating markets considerably reduced risk, as argued below. Creating a single local price for both trading between and within countries reduced the number of transactions needed to sell abroad, increased the size and therefore liquidity of the market, and overall reduced transaction costs. The planned future replacement arrangements will no doubt be an improvement on the default post-transition arrangements but will still lead to two sequential day-ahead markets– one closing in GB before the main auction clears on the Continent.

DAM prices are volatile, as is their difference across interconnectors, so trading over the interconnector is risky and needs hedging contracts. Physical Transmission Rights (PTRs) entitle (but do not oblige unless otherwise specified) the holder to nominate flows over the interconnector or sell the rights. At the Day Ahead stage, (D-1), if the price difference across the interconnector reverses sign, it is unprofitable to nominate the PTR in the original direction, in which case the holder will not make use of the right to deliver. The value of the PTR as an option is then the sum of the positive hourly price differences.

Long-term (LT) PTRs are auctioned before delivery for periods of months, quarters, seasons and years, and can be traded, but under SDAC they become Financial Transmission Rights (FTRs) at the Day Ahead (D-1) stage that entitle the holder to the congestion revenue. EU Member States can also issue LT FTRs either as options or obligations, but under the EU's Forward Capacity Allocation (FCA) Guideline[6] they cannot issue both PTRs and FTRs at the same bidding zone border (FCA, Art. 31(6)).[7] Under the SDAC, GB only uses PTRs with the Continent, but the two interconnectors with the SEM issue FTR options (SEM, 2015). Options can provide a partial hedge against cross-border price differences, but only for hours in which the flow is in the direction of the FTR.

To solve the problem of a complete hedge across borders, the transmission rights would need to be obligations, not options, and in that way would correspond to the standard CfD. There are considerable advantages in choosing obligations rather than options for hedging, as we shall argue below.[8] They bring more competition to bear in each market as

[6] Under Commission Regulation (EU) 2016/1719

[7] Art 31(6) states "The allocation of physical transmission rights and FTRs — options in parallel at the same bidding zone border is not allowed."

[8] EFET (European Federation of Energy Traders) has argued strongly for obligations rather than options (e.g. in ENTSO-E's Market ESC, 3/12/2015) and there is a long history of academic papers arguing for such obligations (e.g. O'Neill et al., 2002).

they allow netting of trades on interconnectors,[9] so that more FTRs can be issued than the physical capacity of the interconnector, provided they are offset by countertrades. Options are necessarily limited in volume to the capacity of the interconnector. However, almost universally in Europe the prevalent choice is for options, and as our interest is primarily on trade with the IEM, the relevant LT capacity contract is a PTR option. For concreteness, we consider the IFA interconnector between GB and France and consider the other two interconnectors in Appendix A.

3.2 The difference between forward and spot electricity markets

Forward markets allow traders to buy and sell standardised contracts for a future period, typically a month, quarter, season or year. Within a country the standard contract is a financial contract - a two-side CfD, and as such is an obligation for the buyer facing a price below the strike price to pay the seller, and the seller facing a price above the strike price to make up the difference to the buyer. The typical and most liquid contract is for baseload, although larger markets may be able to support peak and less often, off-peak contracts. Most consumers have a daily pattern of demand that varies and will need to supplement baseload contracts with additional buying and selling of hourly amounts in the "spot" market, of which the most liquid is the DAM, with responses to later information (outages, updated wind forecasts, etc.) in Intraday Markets (IDMs), and finally in the Balancing or Real-time Market. The liquidity of these spot markets is therefore critical for the efficient working of an unbundled and liberalised electricity market. For example, in the SEM during the first quarter of 2020 the DAM accounted for 78% of the market value, followed (in temporal sequence) by IDM1 with 5.83%, IDM2 with 2.82%, IDM3 with 0.84%, IDC (the continuous IDM) with 0.24%, and finally, the Balancing Market with 12.30% (SEM, 2020).

Trading across interconnectors in forward markets has similarities (typically baseload for varying durations) but important differences, in that the GB-FR PTR is an option, not an obligation. Holding an equal volume of PTRs in both directions gives the full congestion value of the interconnector, which may be useful for a trader but is not helpful for a generator, and is probably the main reason by traders dominate interconnector trade. Appendix D gives examples of how these contracts work under SDAC.

4. The consequences of Brexit

From 1 Jan 2021, GB and the SEM are no longer part of the SDAC, and therefore will not be able to participate in the EUPHEMIA EU-wide auction platform. According to the UK Government (31/12/20):[10]

> The UK government has concluded a Free Trade Agreement with the EU to come into effect following the transition period, ending 31 December 2020. This agreement provides a framework for future electricity trading across interconnectors between the UK and the EU. The agreed model of trading will take time to develop and will not be in place for 1 January 2021. Previously developed alternative arrangements will need to be implemented in the interim, which will endure until the agreed trading model can be put in place.

[9] If a seller is obligated to move M MW from A to B, then that capacity M can be resold from B to A, and netted off to release more capacity.

[10] https://www.gov.uk/government/publications/trading-electricity-with-the-eu/trading-electricity-with-the-eu

In Northern Ireland, the Ireland/Northern Ireland Protocol to the Withdrawal Agreement provides the basis for the continued operation of the Single Electricity Market after 1 January 2021. The UK government is supporting the Department for the Economy in Northern Ireland to implement the Single Electricity Market provisions at Article 9 and Annex 4 of the Protocol, which apply key elements of European energy law in Northern Ireland, which are largely devolved, to enable the effective operation of the Single Electricity Market across the island of Ireland.

From 1 January 2021 cross-border flows across electricity interconnectors will no longer be governed by EU legislation which provides for efficient trade and cross-border cooperation in operating the electricity system. In accordance with the agreed UK-EU FTA, a new model of efficient electricity trading across interconnectors will be developed, including for trade between Great Britain and the Single Electricity Market. These arrangements will not be in place for 1 January 2021.

The island of Ireland is in a special position under the *Withdrawal Agreement*, which maintains the integrity of its Single Electricity Market (SEM). The SEM Committee published an updated information note regarding a 'no deal' Brexit on 27 November 2019:[11]

From 1 January 2021, regardless of the outcome of the future partnership negotiations between the EU and the UK, the SEM will continue to operate as an all-island market. Trade between the SEM and the market in Great Britain, through the Moyle and EWIC interconnectors, will also continue, although this trade may be less efficient, as it will no longer be possible for some platforms that currently operate under EU rules to continue to do so."

Nemo Link (to France) already has in place a set of Non-IEM Access Rules that have been approved and will be operational from 1st January 2021. Nordpool states that

From 31 December 2020 Nord Pool's day-ahead auction has a new gate closure time of 09:50 GMT with results available no later than 10:00 GMT. In the island of Ireland, the SEM-GB intraday auctions (IDA1 & IDA2) continue to operate with shared order books between power exchanges, offering implicit capacity between the island of Ireland and GB.

Ofgem published its guidance as follows:

GB's electricity interconnectors to Continental Europe will switch from implicit to explicit trading arrangements. This is when transmission capacity on the interconnector is auctioned to the market separately from electrical energy, and the switch in arrangements will happen at the end of the transition period.

For GB's interconnectors to the Irish electricity market, market capacity will be allocated via implicit intraday auctions. We do not expect to receive updated Access Rules ahead of the end of the transition period.

The individual interconnectors have published the day-ahead timings, and for IFA (Interconnexion France Angleterre, the 2,000 MW link to France):

Day Ahead implicit auctions will cease, to be replaced by an explicit day ahead auction, hosted on the JAO platform for both IFA and IFA2.
DA Auction Window 09:40-10:00 CET

[11] At https://www.semcommittee.com/news-centre/sem-committee-statement-operation-sem-after-end-brexit-transition-period

DA Nomination Window 12:05-14:00 CET
UIOSI - Unused LT (Long term) capacity will be re-allocated in the Day Ahead explicit auction, and hence will be paid out at the clearing price of this auction.

Britned (the 1,000 MW link to the Netherlands) gives the following timeline shown in Figure 1, which shows that explicit capacity auctions will be staggered throughout the morning, starting with the BritNed interconnector, followed by IFA, IFA2 and finally Nemo Link. Auction bids are submitted before the GB DAM results are known, but the decision whether to nominate trades over the interconnectors takes place after both the GB and EU DAM prices are announced (the SDAC prices are announced before 13:00 CET).

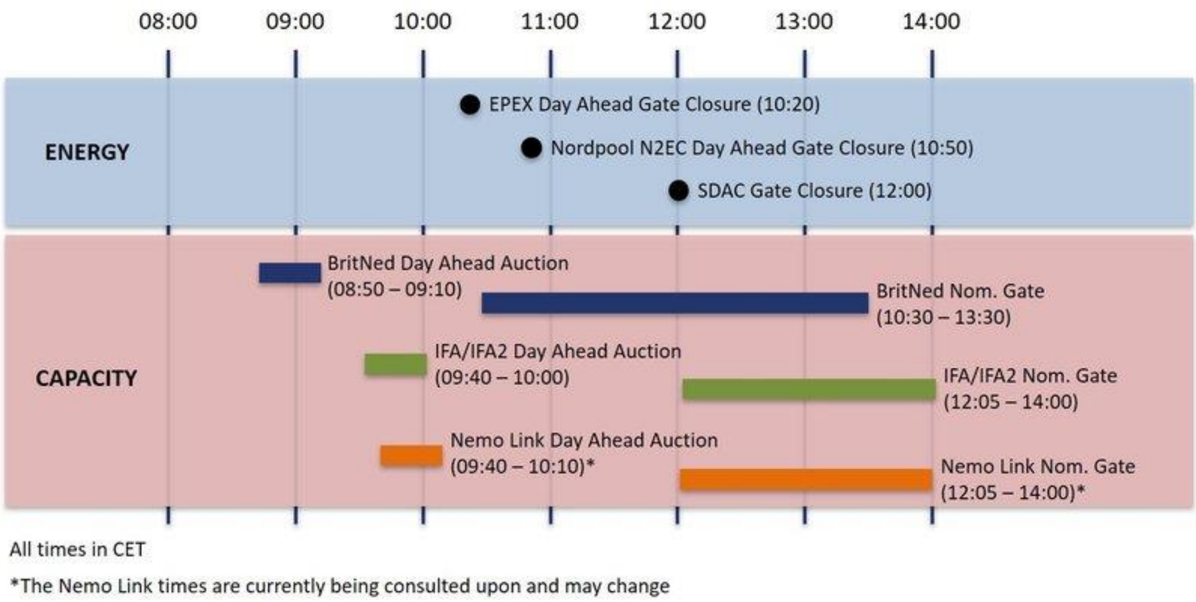

Figure 1 Overview of GB Day Ahead Auctions

The rules for explicit auctions are set out on the Joint Allocation Office (JAO) website[12] *as Rules for Daily Capacity Allocation on the GB-Belgian Border* (August 2019) "where GB is not part of the EU Internal Energy Market for Day Ahead timescales." This note will consider two auction designs – the default JAO design (whose bidding rules are set out in Appendix C) and its likely replacement of Multi-region loose volume coupling, but with the addition of firm FTRs. The relevant features of the JAO auction are summarised below.

4.1 The JAO explicit auction

The key point is that actors submit hourly bids for willingness to pay to use the interconnector in a given direction. It is implicitly a measure of the price difference across the link, with no explicit prices at each end, as in the SDAC auction. The interconnector can sell capacity in both directions, and unless everyone is convinced that flows will always be in one direction, there will be appetite for acquiring capacity in both directions (particularly from traders) at a positive price (one of which may be very low, but an option likely still has some

[12] At https://www.jao.eu/support/resourcecenter/overview

value). Bids are added up in each direction until full capacity is reached in that direction, and the direction that gives the highest congestion revenue wins, and determines the direction in that hour to provide to the SDAC DAM. We can now distinguish a number of additional hourly prices, with notation as follows:

p_{Ch} price in the SDAC DAM in country C (e.g. FR) in hour h;

P_{GBh} the GB DAM price, clearing after the GB auction but before the SDAC auction (capital P indicates an uncoupled price, lower case in the SDAC);

(s_{GB}, P_{GB}) CfDs signed forward in GB at strike price s_{GB} and settled at the GB DAM *daily average* price (hence no subscript h), similarly (s_{FR}, p_{FR}) in France;

V_{FtGh} The GB D-1 auction price in hour h for the option on capacity on IFA from FR to GB, exercised if in expectation $P_{GBh} > p_{FRh}$, in the set of hours h^*;

As in Appendix D, consider a French generator choosing between selling in GB against selling hedged with a CfD in FR (the least risky option open to the French generator). The basic unhedged starting position for selling in GB (with no CfDs or PTRs bought forward) is

a) Generator buys IFA at D-1 from FR to GB at V_{FtGh} for the set of hours h^* expected to be profitable, sells in GB DAM for these hours and submits corresponding FPNs[13] in GB, and at D-1 offers the remaining h^{**} hours into SDAC and informs the French System Operator that he will generate in all hours. Finally, after all prices are known, nominates those trades in hours $h^{*\prime}$ that are revealed to be profitable.

Following this strategy, the French generator expects to sell for the h^* hours in GB. In other hours h^{**} when exporting is considered unprofitable, she offers and receives p_{FR} from FR SDAC. Income is $\sum_{h^*} (P_{GBh} - V_{FtGh}) + \sum_{h^{**}} p_{FRh}$.[14] If there are (random) forecasting errors, ε_h, in the later DAM price differences, then for $h = h^*$, $V_{FtGh} = P_{GBh} - p_{FRh} - r + \varepsilon_h$, where r is a risk premium designed to rule out unprofitable nominations. Income is $\sum_{h^*} (p_{FRh} + r - \varepsilon_h)$ in these hours while in the remaining hours it is $\sum_{h^{**}} p_{FRh}$. Total income is $\sum_{h^*} (r + \varepsilon_h) + \sum_h p_{FRh}$. The risk exposure is effectively to the FR SDAC DAM prices, with some additional uncertainty about errors introduced by uncoupling IFA. The remaining cases address various elements in this risk viewed from the day-ahead and month-ahead stage (or even earlier with suitable contracts).

Hedging different steps (and in all cases informing the French System Operator that she will generate)

b) As a) but also hedge FR risk with FR selling a FR CfD (s_{FR}, p_{FR}), leading to income $\sum_{h^*} (r + \varepsilon_h) + \sum_h s_{FR}$, leaving only forecasting risk exposure in trading hours at D-1, but again only selling (cautiously) for h^* hours in GB. The only difference with the reference hedged FR position is $\sum_{h^*} (r + \varepsilon_h)$, where r is chosen to make this sum

[13] Final Physical Notification to the System Operator that he will deliver into GB.

[14] This is a simplification, in that if markets reveal the FPN is unprofitable in some of the h^* hours, either the generator will pay an imbalance charge in GB or will nominate an unprofitable trade, either way earning less. Empirically this is dealt with later by setting a risk premium that discourages bidding that leads to such losses, at the cost of a lower utilisation.

small when averaged over many days. Its determination is an empirical issue for the empirical section.

c) As b) but also hedge by selling GB CfD (s_{GB}, P_{GB}), and hence committing to selling in all hours in GB. The generator imports into GB with nominated capacity on IFA in hours $h*$ (and later submits FPNs in GB for these deliveries) and sells in GB DAM; and at D-1 offers all hours into SDAC. The GB settlement exposure is only covered in profitable trading hours, so that there is an additional risk of $\sum_{h**} (P_{GBh} - s_{GB})$ to add to $\sum_{h*} (r + \varepsilon_h) + \sum_h s_{FR}$, or additional risk $\sum_{h**} P_{GBh} + \sum_{h*} (r + \varepsilon_h)$ compared to the reference hedged FR position. As such it looks relatively unattractive, and may be the major cost of uncoupling, in reducing the extent of sellers in the GB market; effectively creating a tariff barrier to imports that might reduce GB prices.

d) As c) but generator buys a baseload PTR from FR to GB for v_{FtG}, nominates profitable trades, sells in GB DAM and submits corresponding FPN in GB in hours $h*$, and at D-1 offers all hours into SDAC. This is the same as c) except for trading profit $\sum_{h*} (V_{FtGh} - v_{FtG})$, which does not add additional risk, but might reduce overall uncertainty viewed at M-1.

All of these involve varying degrees of price risk exposure, compared to just trading with CfDs in France, raising the natural question of how these risks might be avoided. Clearly, the more quickly the proposed "Multi-region loose volume coupling" required by the FTA is agreed and introduced, the better. Meanwhile the interim market structure described in Figure 1 will be used to guide estimates of the cost of uncoupling.

5. Empirical estimates on loss in trading

The loss in interconnector efficiency has a number of elements. The most important social cost is that the interconnector is under-used as bidders will be cautious in paying for capacity if there is a risk that it would turn out not be profitable to nominate once the DAM prices are known, given that selling in GB requires a prior commitment to deliver there. One of the key risks is that the interconnector will be importing from what turns out to be a high price zone into a low cost zone, and the resulting Flow Against Price Difference (FAPD) will cause losses that need to be addressed by more cautious bidding, adding a risk premium to the forecast price difference.

The second impact is that bidders will undervalue (on average) capacity because of their risk aversion, and hence the congestion revenue paid by traders to interconnector owners will be lower. This reduced congestion revenue will have additional costs if it discourages potentially profitable investment in future interconnectors. Clearly, the value of interconnectors like IFA will be enhanced the lower is the perceived risk of trading explicitly. The main risk is bidding incorrect price differences – specifically paying more than it is worth if going in the predicted direction and, if the flow is in the opposite direction to that predicted, losing the capacity price bid as the flow will not be nominated.

The most obvious way to reduce this risk is to improve forecasting accuracy, and the larger traders are doubtless devoting resources to do just that, so they can offer more competitive pricing for trading for generators and suppliers. If traders efficiently arbitrage cross-border price differences, domestic players can concentrate on their local markets without the worry that they are losing out on more attractive cross-border trades. The cost to interconnector owners of inefficient arbitrage is considerable: a €1 of discount to fair value if the interconnector is available for 8,000+ hrs/yr is worth €16+ million/yr on the 2,000 MW IFA (where fair value is measured avoiding subsequent FAPDs).

The rest of this section describes the methods for forecasting the price differences between GB and France, compares the accuracy of different forecast rules, and estimates trader's risk premium under different trading rules after Brexit, using the best forecast method identified, but locking in trade expectations in the face of revealed FAPDs. This then allows a (possibly over-stated) calculation of the social cost of uncoupling and the loss to interconnectors. No doubt sophisticated traders will be able to improve on these estimates, but whether they pass that on in lower margins will depend on the extent and vigor of competition in the explicit auction.

4.1 Forecasting methods

With explicit auctions, traders need to forecast the cross-border price difference before submitting bids. If neither the GB nor the EU day-ahead (DA) hourly prices are known when the auction bids are entered, the traders will need to forecast both GB and FR prices, or effectively, the GB-FR price difference, to inform the bid and direction. We compare the three most common econometric methods with a naïve method for forecasting the price differences between the two countries.[15] Consider first just forecasting the DA hourly prices for FR (and GB if necessary, separately), and then take the difference.

The *Naïve Forecasting Method* (NFM) sets the forecast of DA hourly prices equal to prices 24 hours earlier where both days are weekdays (thus for Tuesday-Friday), but where at least one day is a weekend (i.e. for Saturday-Monday) the forecast is the price 168 (= 24*7) hours earlier:

$$\begin{aligned} p_{t,h} &= p_{t-1,h} + u_{t,h}, \text{ for Tuesday-Friday} \\ p_{t,h} &= p_{t-7,h} + u_{t,h}, \text{ for Saturday-Monday} \end{aligned} \tag{1}$$

where $p_{t,h}$ denotes the DA price (for FR or GB) for hour h on day t, and $u_{t,h}$ are forecast errors.

Fezzi and Mosetti (2020) find that *Simple Linear Regressions* (SLR) with only two parameters can perform unexpectedly well if estimated on extremely short samples. The second method is their SLR:

$$p_{t,h} = \alpha_0 + \alpha_1 q_{t,h} + u_{t,h}, \tag{2}$$

where $q_{t,h}$ is the DA forecast of electricity demand.

Autoregressive models with exogenous variables (ARX) are widely used for electricity spot price forecasting. The ARX model takes the form

[15] Machine learning methods such as Artificial Neutral Networks and Support Vector Machines are also attempted, but their forecast errors are much greater than the proposed econometric methods. Therefore, in this article, we no longer consider machine learning methods as options. For more literature on spot market forecasting, see for example, Keles et al. (2016), Mirakyan et al. (2017), Marcjasz et al. (2020).

$$p_{t,h} = \beta_{0,h} + \sum_{i=1}^{m} \beta_{i,h} p_{t-i,h} + \sum_j \theta_{j,h} X_{j,t,h} + u_{t,h}, \tag{3}$$

where m represents the AR lags, $X_{j,t,h}$ contains exogenous variables including DA forecasts of domestic and foreign (including GB, France, France, Germany, and The Netherlands) electricity demand and renewable generation of domestic and foreign countries, coal and gas prices, EUA prices, as well as day-of-week dummy variables.

Vector autoregressive models with exogenous variables (VARX) go further to capture relationships of prices among different hours of the day. A VARX model takes the form

$$P_t = \Gamma_{0,t} + \sum_{i=1}^{m} \Gamma_{i,h} P_{t-i} + \Theta X_t + U_t, \tag{4}$$

where P_t is a 24×1 vector of hourly DA prices for day t and X_t is a vector containing all exogenous variables. To substantially reduce the number of unknown coefficients, the matrices Γ_i's are diagonal so only prices for the same hours in previous days have predictive power for today's price. Similarly, exogenous variables with hourly frequency, such as the DA forecasts of demand and renewable generation, only have predictive power on today's prices for the corresponding hour, meaning that their coefficient matrices are also diagonal.

Equations (1) - (4) provide forecasts of DA prices, which are then used to forecast the price difference. One can test whether it is more efficient to directly forecast the price difference, in which case, $p_{t,h}$ in (1) - (3), and P_t in (4) are replaced by the price differences between GB and FR.

If (as is not at the moment the case) the GB DA market were cleared before the auction, it would only be necessary to forecast the FR price, and then predict the price difference between GB and FR. In this case, GB's market clearing prices are included in regressions (2)-(4) as predictive variables.[16] If that improves efficiency and reduces the social loss of uncoupling a change in market and auction timing might be relatively simple to introduce. Examining this scenario therefore offers the prospect of a relatively simple immediate improvement to trading arrangements.

4.2 Data

GB's DA electricity prices in Euros come from the Nord Pool, and the DA electricity prices for FR come from the ENTSO-E transparency platform. The day-ahead forecast on renewable generation and demand for GB and FR are collected from the ENTSO-E transparency platform. Because GB and FR are heavily interconnected with France, Germany, and the Netherlands, we also include forecasts of the Belgian, German, and Dutch demand and renewable generation as predictive variables (also from the ENTSO-E transparent platform).[17] Where data are at 15-minute frequency they are aggregated to hourly frequency. Missing data are replaced by the out-turn values (e.g. for generation).

[16] In this case forecasting the French price and forecasting the GB-FR price difference are equivalent, as the GB price enters to the right-hand-side of regressions.

[17] Germany used to have a single price zone with Luxemburg and Austria, but in August 2019 Austria separated from Germany. In our analysis, the forecast on DE's demand and renewable generation is always the forecast for the DE-AT-LU price zone --- for periods before August 2019, we use the forecast for the DE-AT-LU market; while for periods after August 2019, we sum up the forecasts for DE-LU and AT markets.

The ICE Rotterdam Coal Futures price is taken as a proxy for the daily wholesale coal price and the GB National Balancing Point (NBP) gas price is taken as the spot price for natural gas (an excellent proxy for EU gas prices). Both prices are converted to €/MWh_{th}, using the conversion factors from *Greenhouse gas reporting: conversion factors 2019*.[18] Finally, the daily auction price for CO_2 - the EU Allowance price - comes from Bloomberg. When calculating the congestion revenue between GB and FR, we also need the day-ahead interconnector capacity as well as the day-ahead scheduled flow (between 31st Jan 2019 and 30th Jan 2020), collected from the Nord Pool.

4.3 Forecast process

Unexpected events such as nuclear outages and extremely cold winter days can cause extreme prices driven by high demand and/or low supply. Extreme prices cannot be predicted by conventional econometric methods. Instead, probability models are preferred (Hagfors et al., 2016). We leave this to future research. Furthermore, we find that including extreme prices as predictive variables can distort the values of estimated coefficients, resulting in poor forecast accuracy (not reported). The problem is avoided by setting upper and lower bounds for hourly DA prices entering the regressions. The bounds are set at four times the standard deviation of the hourly DA prices. Any values greater than that deviation from the sample mean is replaced by the upper or lower bound.

Although our analysis mostly focuses on IFA which was coupled in 2014, later we will replicate the analysis on BritNed and Nemo. As Nemo was commissioned on 31st Jan 2019, for all three interconnectors we collect data from 31st Jan 2018 to 30th Jan 2020. Data for the first 365 days are used for training and the data for the second 365 days are used for out-of-sample validation. The out-of-sample forecast is conducted recursively. For example, the forecast of the DA prices on 31st Jan 2019 is based on the training result using data between 31st Jan 2018 and 30th Jan 2019. The forecast of the DA price on 1st Feb 2019 is based on the training result using data between 1st Feb 2018 and 31st Jan 2019, and so on.

4.4 Error measures

Conventional error measures include the *Mean Absolute Errors (MAE)* and *Mean Squared Errors (MSE)*. Denoting the forecast of price difference as $\hat{d}_{t,h}$ and the market clearing price difference as $d_{h,t}$, the MAE is

$$\text{MAE}=\frac{1}{HT}\sum_{h=1}^{H}\sum_{t=1}^{T}\left|\hat{d}_{t,h}-d_{h,t}\right|,$$

and the MSE is

$$\text{MSE}=\frac{1}{HT}\sum_{h=1}^{H}\sum_{t=1}^{T}\left(\hat{d}_{t,h}-d_{h,t}\right)^2.$$

In our case, $T=365$ is the total number of days for out-of-sample validation and $H=24$ is the total number of hours in a day.

[18] https://www.gov.uk/government/publications/greenhouse-gas-reporting-conversion-factors-2019

MAE and MSE estimate the accuracy of forecasts, whereas a social planner might be more interested in the loss from imperfect forecast. Under perfect forecasting or when IFA is coupled, in the DA market the capacity will be efficiently used and the congestion revenue (i.e. the product between the price difference and the flow) is maximized. However, when the market is uncoupled, the efficiency of IFA will depend on the forecast accuracy of DA prices (or price differences), and the congestion revenue will not be maximized. Our next three error measures are therefore measuring losses from imperfect forecasts.

The next error measure is therefore the percentage of *Flows Against Price Difference (FAPD)*, the standard ACER metric of interconnector inefficiency. It measures the percentage of time that the interconnector flow goes from the higher-price market to the lower-price market, or equivalently, that the sign of the predicted price difference differs from that of the actual price difference. Therefore, the FAPD can be expressed as

$$\text{PAFD}=\frac{1}{2HT}\sum_{h=1}^{H}\sum_{t=1}^{T}\left|sign\left(\hat{d}_{t,h}\right)-sign\left(d_{h,t}\right)\right|.$$

This will represent a failure to use the interconnector in the correct direction.

4.5 Forecasting results

We consider three different scenarios. In the first two scenarios (the current arrangement), neither GB's nor the French DA hourly prices are known when bids are made to the explicit interconnector auction. Scenario 1A directly forecasts the price difference between GB and FR so that in (1)-(4), $p_{t,h}$ and P_t denote price differences instead of DA prices. In (2), $q_{t,h}$ becomes a vector of two variables, namely the DA forecast of GB and FR electricity demand. Scenario 1B forecasts GB and FR DA prices separately and then takes their difference.

In Scenario 2, a relatively simple and quick reform, the GB DA hourly market is run and clears before the interconnector auction. In this scenario, forecasting the price difference based on the revealed GB price would deliver the same result as forecasting the French DA price based on the revealed GB price and then taking the price difference.

Table 1 presents the error measures of forecast results. Among the four proposed econometric methods, ARX substantially outperforms others, followed by VARX. On the other hand, regardless of the forecast method, Scenario 2 always has the lowest MAE and MSE, while Scenario 1A or 1B has the lowest FAPD. Under the market timings in Scenario 2, traders make better forecasts of relative values, while in Scenario 1A and 1B, they make better forecasts of the sign of the price difference. This implies that there is no unambiguously preferred ordering of market timings, which should be determined by the timing that minimizes social loss. That loss will depend on the relative importance of the loss of FAPD against improved willingness to trade from improved price forecasts.

Traders are assumed able to estimate any impact the subsequent trade flows have on the GB DAM or that any forecast errors on trade flows are small compared to the market served by the GB DAM and so do not impact the DAM price. The social cost estimates are probably higher than would be the case if traders were to adjust their decisions in subsequent intra-day markets that open after the DAM prices are known, and which offer the prospect of changing the nominated flows on the interconnectors.

Table 1 Error Measures for IFA forecasts

Methods	Scenarios	MAE €/MWh	MSE (€/MWh)^2	FAPD
NFM	1A,B	7.33	149.48	11.46%
	2	6.24	78.46	16.92%
SLR	1A	6.96	93.97	9.92%
	1B	8.33	125.94	12.23%
	2	5.88	70.60	13.78%
ARX	1A	5.49	66.45	**9.78%**
	1B	5.50	66.55	9.90%
	2	**3.89**	**33.81**	11.92%
VARX	1A	5.71	71.90	11.42%
	1B	5.72	70.94	11.26%
	2	4.38	41.53	13.55%

Note: In Scenario 1A, both GB and FR DA prices are unknown, and we directly forecast the price difference; In Scenario 1B, both GB and FR DA prices are unknown, we separately estimate the DA prices and then take the difference; In Scenario 2, the GB DA price is revealed before the auction, and we directly forecast the price difference using the GB DA price as a predictor.

4.7 Risks from the traders' perspective

Once interconnectors are uncoupled, the immediate concern is the impact forecasting risk would have on the mean and variance of traders' revenue from buying interconnector capacity in the explicit auction and then buying and selling in the relevant DAMs, as that will affect their willingness to buy capacity and hence on interconnector revenue. For that we can simulate the effect of submitting bids into the explicit auction based on the forecast of price difference, less a risk premium, and calculate the quarterly and/or annual profit from trading, assuming that the expected price differences determine actual trade directions (regardless of subsequent information from the SDAC DAM prices).

Algebraically, for a particular hour, denote the risk premium as $r > 0$, the transmission capacity as C, a marginal trader's forecast of the price difference as $\hat{d}$, and the actual price difference as d. The volume that marginal traders would purchase in the explicit market is

$$\hat{V} = \begin{cases} C, \text{ if } \hat{d} > r \\ -C, \text{if } -\hat{d} > r, \\ 0, \text{otherwise} \end{cases} \quad (5)$$

and the marginal traders' profit for that hour is:

$$\Pi = \begin{cases} [d - (\hat{d} - r)] \times \hat{V}, & \text{if } \hat{d} > r \text{ and } d > 0 \\ [d - (\hat{d} + r)] \times \hat{V}, & \text{if } -\hat{d} > r \text{ and } d < 0 \\ -(\hat{d} - r) \times \hat{V}, & \text{if } sign(\hat{d}) \neq sign(d) \text{ and } \hat{d} > r \\ -(\hat{d} + r) \times \hat{V}, & \text{if } sign(\hat{d}) \neq sign(d) \text{ and } -\hat{d} > r \\ 0, & \text{otherwise} \end{cases} \quad (6)$$

$\Pi = 0$ when $-r < \hat{d} < r$, marginal traders will not participate in the explicit auction.[19]

For example, suppose traders' risk premium is €1/MWh. If the forecast of GB-FR price difference is €10/MWh, they would bid €9/MWh in the explicit auction for GB importing from FR. After the DA market clears, if the clearing price difference is negative or greater than €9/MWh, they lose. Otherwise, they make a profit at the expense of the interconnector. The profit (and losses) from trading (for each hour) is added to the cumulative balance of gains and losses and periodically checked. If they hardly ever make a cumulative loss then rerun the calculations with a risk premium of €0.5/MWh, with bids of €9.5/MWh in the explicit auction, and so on. Eventually, when the traders' cumulative profit is close to zero, the corresponding risk premium is taken as the risk premium of the marginal traders.

From formula (6), the traders' loss from trading mainly comes from two elements – forecasting the wrong sign of the price difference or overestimating the price difference (and these are why the risk premium is essential). Figure 3 presents a scatter plot between the actual GB-FR price difference and the forecast values using ARX under Scenario 2. The dots distribute evenly around the 45-degree line. In Figure 3, only a small proportion of dots are within the second and fourth quadrants, indicating that most of our forecasts are of the right sign. When the sign of our forecast is wrong, the associated loss is (mostly) is small thanks to the risk premium. Put another way, the trader's loss mainly comes from overestimating the price difference (instead of forecasting a wrong sign).

Figure 3 Actual *vs*. Forecast Price Differences using ARX under Scenario 3

Given the results in Table 1, we consider the marginal trader using ARX as the forecast method. We also consider the three different scenarios described above. Table 2

[19] Although marginal traders do not participate, less risk-averse infra-marginal traders (or those with more optimistic forecasts) may, resulting in some flows in this case. They would on average make losses and eventually presumably leave the market. See 4.8 for one way of handling possible trades in this region.

presents the annual profit for traders between 31st Jan 2019 and 30th Jan 2020, under different risk premia. It suggests that when the GB DA price is revealed before the explicit auction (Scenario 2), the risk premium that allows marginal traders to make just above zero annual profit from IFA DA trading is €1.32/MWh, considerably below the other scenario values. However, under the current trading rule (i.e., Scenarios 1A and 1B), the risk premia are greater, lying within €2.35/MWh and €2.39/MWh. Given our assumption that competition among traders is sufficiently intense to drive down the risk premium until profits are negligible, traders' should be indifferent to the order of the timing of the explicit auction and the GB DAM.

Table 2 Annual profit under different risk premia trading on IFA (in million €)

	Scenario 1A	Scenario 1B	Scenario 2
Risk premia (€/MWh)	2.35	2.39	1.32
Annual Profit (€ million)	0.10	0.06	0.09

It seems plausible that traders would frequently update their risk premium based on the trading result during the previous, for example, three months. Figure 4 presents the trader's dynamic risk premium based on the trading results during the past 91 days.[20] The 91-day risk premia in Scenarios 1A and 1B becomes extremely high in the second half of 2019, which is not the case in Scenario 2. The reason is that the trader is able to make much better forecasts (in MAE and MSE) knowing the GB price, resulting in more profitable trading and hence smaller risk premia.

Figure 4 91-day Risk Premia on IFA

[20] Without the loss of generality, we have removed the date with extreme prices (i.e. 8th June 2019, when the FR, BE, NL price reached negative almost for the entire day) in Figures 5 and 6, as well as the corresponding figures in the Appendix.

Finally, Figure 6 shows the 91-day rolling standard deviations of the traders' hourly profit, when the risk premium is set at €1.32/MWh (i.e. when a marginal trader's annual profit from trading is just above zero in Scenario 2). The standard deviation of hourly profit can be interpreted as a proxy for the volatility of trading, and risk aversive traders dislike volatile markets. Figure 6 confirms that in Scenario 2, the trader enjoys not only lower risk premium, but also a much lower volatility of hourly profit, making reordering the timing of the explicit auction and the GB DAM even more attempting (from traders' perspective).

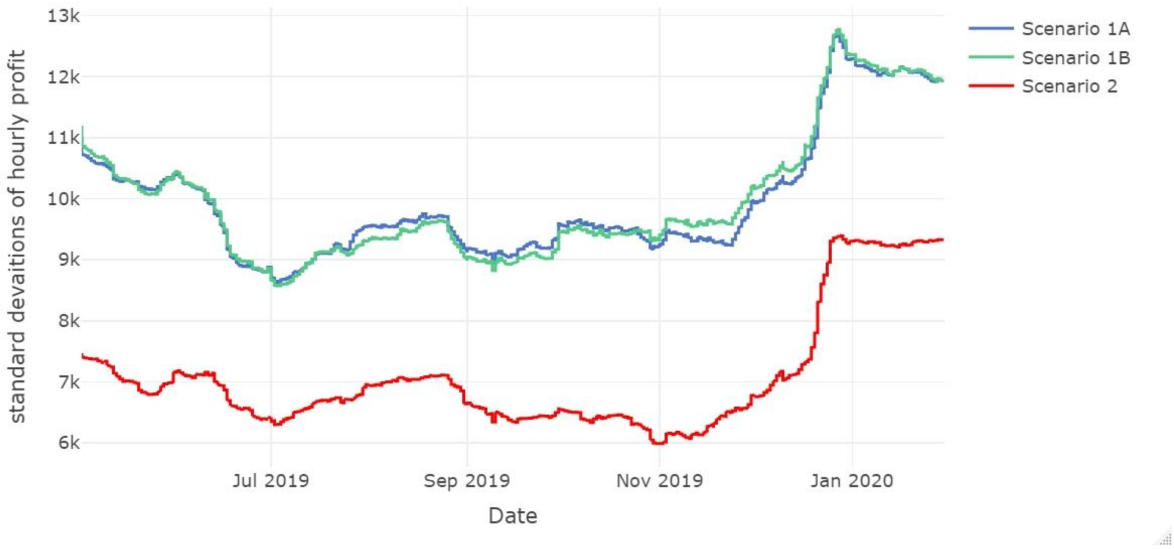

Figure 6 91-day-rolling Standard Deviations of Hourly Profit from Trading on IFA, under ARX Forecasts

4.8 Trading on BritNed and Nemo

GB is also interconnected with The Netherlands through BritNed and Belgium through Nemo. In Appendix A we replicate Section 4.7 on BritNed and Nemo for the same period, finding that the risk premia for BritNed is smaller than IFA, while the risk premia for Nemo is greater than IFA, probably because Nemo is the youngest interconnector among the three (commissioned in 31st Jan 2019), and is less stable during the first several months of operation. The results from all three interconnectors tell a same story: reordering the timing of the explicit auction and the GB DAM is desirable from traders' perspective, because it reduces the risk premium for the marginal trader and reduces the volatility of hourly profit.

4.8 The cost of uncoupling

The inefficiency resulting from uncoupling can be measured as the percentage of time that an interconnector is *Inefficiently Used (IU)* when it should be:

$$\mathrm{IU} = 1 - \frac{\sum_{h=1}^{H}\sum_{t=1}^{T} 1\left(\hat{V}_{t,h}=V_{t,h}=C_{t,h}|d_{t,h}>0\right)+1\left(\hat{V}_{t,h}=V_{t,h}=-C_{t,h}|d_{t,h}<0\right)}{\sum_{h=1}^{H}\sum_{t=1}^{T} 1\left(V_{t,h}=C_{t,h}|d_{t,h}>0\right)+1\left(V_{t,h}=-C_{t,h}|d_{t,h}<0\right)},$$

where the numerator is the total number of hours that the interconnector reaches its capacity limit, $C_{t,h}$ denotes the capacity of the interconnector, and $1(\cdot)$ is an indicator function. $\hat{V}$ follows formula (5) when $|\hat{d}| > r$, but when $-r < \hat{d} < r$, we assume, perhaps optimistically, given the losses they will incur, the interconnector flow is $C * \hat{d}/r$, purchased by infra-marginal traders.

The *Commercial Costs of Uncoupling (CCU)* are the loss in congestion revenue relative to the total congestion revenue under market coupling due to imperfect forecasts. Given observed net import under market coupling ($V_{t,h}$) and the estimated net import when the market is uncoupled ($\hat{V}_{t,h}$ from formula (5)), the CCU is

$$\text{CCU}=V_{t,h} \cdot d_{t,h} - \hat{V}_{t,h} \cdot \tilde{d}_{t,h},$$

where $\tilde{d}_{t,h}$ is an estimate of the price difference when the market is uncoupled. Uncoupling may result in a change in flows, which further change the DAM prices. Given the estimates of the marginal slope of the electricity supply curves in Guo and Newbery (2020), we can further estimate the price difference between GB and FR when IFA is uncoupled. Algebraically, given the slope of the supply curve as $\hat{\theta}_{GB}$ and $\hat{\theta}_{FR}$,[21] $\tilde{d}_{t,h}$ can be expressed as:

$$\tilde{d}_{t,h} = d_{t,h} + \left(\hat{\theta}_{GB} + \hat{\theta}_{FR}\right) \cdot \left(V_{t,h} - \hat{V}_{t,h}\right).$$

Finally, the *Social Cost of Uncoupling (SCU)* is the increase in generation cost caused by reducing the extent to which exports from the lower cost country are reduced:

$$\text{SCU} = \left| \frac{1}{2}\left(d_{t,h} + \tilde{d}_{t,h}\right) \cdot \left(V_{t,h} - \hat{V}_{t,h}\right) \right|.$$

The SCU is estimated under the standard assumption that the short-run demand is inelastic. Provided all externalities are internalised through charges and subsidies (as was intended for carbon under the EU ETS and the *Renewables Directives*) and that electricity wholesale markets are workably competitive (as they are in GB), market prices would correctly measure the social cost of generation. Further corrections might be needed if carbon prices are not aligned across interconnectors, see Guo and Newbery (2020).

Table 3 lists the IU, CCU, and SCU from uncoupling IFA, BritNed and Nemo in the three scenarios, with bold indicating the least cost options (which, agreeably, are the same for each interconnector). The total commercial cost of uncoupling is about €29 m./yr under the current trading rule, while if the GB DAM price is revealed before the explicit auction, the commercial cost rises to €38 m./yr. The estimated social cost of uncoupling is about €26 m./yr under the current trading rule, but can be as high as €34 m./yr if the GD DAM prices were revealed before the explicit auction. The higher commercial and social costs of uncoupling in Scenario 2 are due to the high FAPD (see Table 2). That is reassuring as there is no conflict between commercial and social objectives and that the current trading rule does not need to be changed. In any scenarios, our (over-) estimated cost of uncoupling is lower than that estimated by Lockwood et al. (2017) and Geske et al. (2020), but compatible with Newbery et al. (2016). The social costs are lower than the commercial costs as the

[21] Guo and Newbery (2020) estimated the marginal slope of electricity supply curves for GB, FR and NL (€0.881/GW, €1.817/GW, and €2/GW, respectively). As BE is heavily interconnected with France, we assume the slope of the BE supply curve to be €1.817/GW, same as FR.

commercial costs are evaluated at the equilibrium price and the social cost includes some infra-marginal values (the average of the initial and final price differences).

Table 3 Rates of inefficient use, commercial congestion income and social cost

	Scenarios	IU	CCU (m€/yr)	SCU (m€/yr)
IFA	1A	7.7%	**16.6**	**13.7**
	1B	8.1%	16.9	14.1
	2	9.3%	21.9	18.2
BritNed	1A	9.2%	**8.4**	**8.6**
	1B	9.1%	8.8	8.9
	2	8.7%	10.4	10.3
Nemo	1A	8.0%	**4.1**	**3.3**
	1B	8.0%	4.4	3.6
	2	10.6%	6.0	5.2
Total	1A	8.3%	**29.1**	**25.6**
	1B	8.4%	30.1	26.6
	2	9.5%	38.3	33.7

5. The case for 'Multi-region loose volume coupling' and firm FTRs

The problem with the JAO auction is that the DAM prices remain implicit and only their difference is revealed. The obvious solution is to make these implied market prices actual market clearing prices by combining the explicit auction with the GB DAM into which buyers and sellers trading within GB can also offer, as well as those wishing to trade across borders. This is the required solution for the SO's to design and implement before April 2022 (see Appendix B). Effectively it mimics some of the advantages of the SDAC coupling but in this case coupling the GB DAM with one side of interconnector trade. In addition, and as part of the market redesign, creating a new auction market in forward FTRs that are obligations, not options, would seem desirable. That is not required by the FTA but nor is it prevented. Under this design there is a new hourly price for FR and prices for the new FTRs:

P_{FRh} the hourly price in FR set in the GB D-1 auction. The GB auction price is the DAM P_{GBh};

f_{FtG} the price of the forward FTR, paying $P_{GBh} - P_{FRh}$ in every hour on the day (possible negative in some hours, requiring payment from the holder, as with a CfD);

Now consider the case of a French generator wishing to hedge is output and suppose that it is profitable to generate in every hour on the day. Selling to a consumer in FR just needs a French CfD, but selling to a consumer in GB needs a CfD in GB (s_{GB}, P_{GB}) and an FTR from FR to GB.

A French generator's profit in each case from generating per MWh in hour h for the day is

a) Selling to FR consumer hedged with CfD: ($s_{FR} - c$);

b) Selling to GB consumer with GB CfD, buying a forward FTR from FR to GB, and offering all output into the D-1GB auction: profit $=1/H \sum_h [(s_{GB} - P_{GBh}) + (P_{GBh} - P_{FRh}) + P_{FRh})] - f_{FtG} - c$.

Arbitrage between case e) and case f) requires

$s_{FR} = s_{GB} - f_{FtB}$.

The combination of the two-sided GB auction and the introduction of firm FTRs removes all price risk of trading in forward markets.

6. Conclusion and policy implications

The UK's departure from the EU and the end of the transition period on 1 January 2021 has created a hiatus between the ending of market coupling and the introduction of 'Multi-region loose volume coupling' required by the FTA. That will take some time to design and introduce, and meanwhile we have established that trade is likely to be less efficient. Our estimate suggests that the loss in congestion revenue from uncoupling is about €29 m./yr, or about 12% of the total congestion revenue under market coupling. The social cost of uncoupling is slightly lower at about €26 m./yr.

As traders will now be exposed to the risk that their ex ante market position and interconnector purchases may lock them into unprofitable trades, their rational response is modelled as attaching a risk premium to their forecasts of price differences, and so they will discount their bids in the explicit interconnector auction. Under the present timings in which the GB DAM closes after the explicit auction, traders have to forecast the price difference between the two separate DAMs. Trading on IFA is risky as inflexible French nuclear generation and highly weather-sensitive demand make prices (and flow directions) harder to predict, so the bid premium is quite high at over €2/MWh. The initial bid premium on Nemo could be as high as €3/MWh, but improved market linking as time passed after commissioning reduced the premium to just over €1/MWh. The less volatile market in the Netherlands and longer period since commissioning results in a lower bid premium on BritNed of under €1/MWh).

The most immediate (and reassuring) policy implication is that there is no need to move the DAM to clear before the explicit auctions open. The case for accelerating the move to loose coupling is to reduce the material losses in congestion revenue and in the social benefits of trading. These costs are smaller than other estimates, and probably overstated as they do not take account of re-nominating and unwinding domestic positions, and/or re-trading in subsequent intraday markets. These actions might improve efficiency, particularly as they affect the full and efficient use of the interconnector and reduce the costs of uncoupling. Improved interconnector profitability would avoid the discouragement to building further interconnectors, of which many are at the design stage and provide an additional argument for accelerating the move to loose coupling.

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Abbreviations

ARX	Autoregressive models with exogenous variables
CfD	Contract for Difference
DA	Day ahead
DAM	Day-ahead market
D-1	the day before (the delivery date)
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
FAPD	Flows Against Price Difference
FTA	Free Trade Agreement (the *Trade and Cooperation Agreement* with the EU that came into force on 1 Jan 2021, see Appendix B)
FTR	Financial Transmission Right
IDM	Intraday Markets
IEM	Integrated Electricity Market
IFA	Interconnexion France Angleterre
JAO	Joint Allocation Office (see Appendix C)
LCR	Loss in Congestion Revenue
LT	Long term
MAE	Mean Squared Error
MSE	Mean Absolute Error
NFM	Naïve Forecasting Method
PTR	Physical Transmission Right
SDAC	Single Day-ahead coupling
SEM	Single Electricity Market of the island of Ireland
SLR	Single Linear Regression
SO	System Operator
VARX	Vector autoregressive model with exogenous variables

Appendix A Replicating Section 4.7 on IFA and BritNed

Regressions (1) - (4) are applied to the price difference between GB and The Netherlands (NL), as well as the price difference between GB and Belgium (BE). Both results suggest ARX to be the forecast method with the highest forecast accuracy. Table A.1 reports error measures of the forecast GB-NL and GB-BE price differences using ARX, for Scenarios 1A (forecasting differences), 1B (forecasting each price separately) and 2 (where the GB DAM closes before the explicit auction). As in Table 1, the MAE and MSE for the forecast price differences in Scenario 2 outperforms those under Scenarios 1A and 1B, but, and critically, the FAPD is smaller in Scenario 1A.

Table A1 Error Measures on ARX-forecast of GB-FR and GB-NL price differences

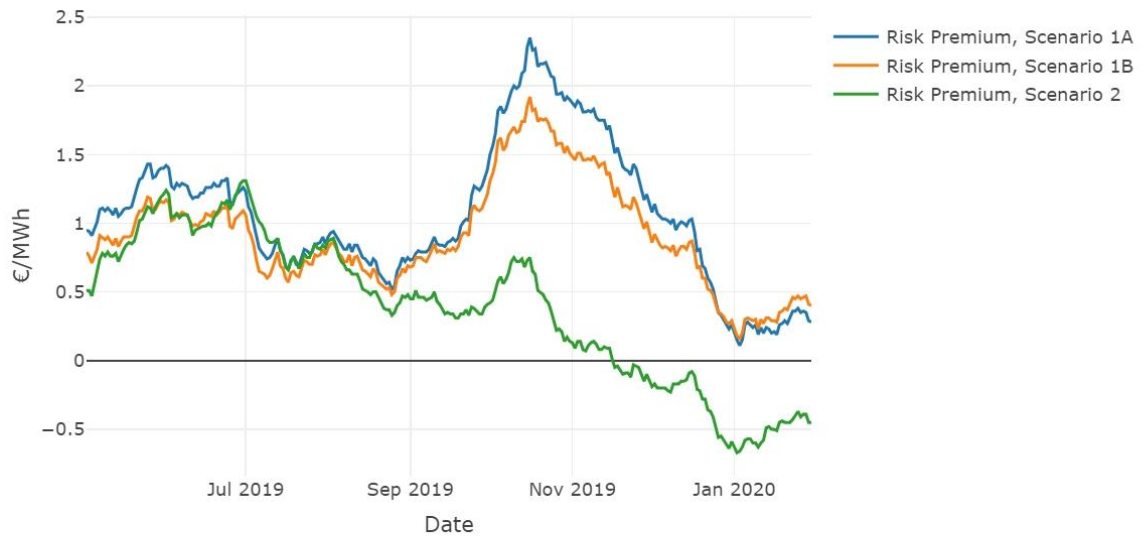
	Scenarios	MAE (€/MWh)	MSE (€/MWh)^2	FAPD
BritNed (GB-NL)	1A	4.48	47.63	**10.48%**
	1B	4.48	47.95	10.81%
	2	**3.59**	**29.98**	12.59%
Nemo (GB-BE)	1A	6.61	247.47	**8.49%**
	1B	6.57	247.75	8.87%
	2	**5.49**	**199.47**	11.98%

Table A2 reports the annual profit for a marginal trader trading at the explicit auction for BritNed and Nemo, under different risk premia. The minimum risk premia for a trader to make non-zero profit in Scenario 1A (which table 3 shows leads to the lowest commercial and social cost) are €0.85/MWh and €3.19/MWh for BritNed and Nemo, respectively.

Table A2 Annual profit under different risk premia (in million €), IFA and BritNed

		Scenario 1A	Scenario 1B	Scenario 2
BritNed (GB-NL)	Risk premia (€/MWh)	**0.85**	0.75	0.24
	Annual Profit (€ million)	0.03	0.04	0.03
Nemo (GB-NL)	Risk premia (€/MWh)	**3.19**	3.08	2.33
	Annual Profit (€ million)	0.03	0.01	0.03

Figure A1 plots the dynamic risk premium for a marginal trader based on the trading results during the past 91 days, when trading in the BritNed and Nemo explicit auction. For both interconnectors, the risk premium in Scenario 2 is almost always lower than those under Scenarios 1A and 2B. The risk premium for BritNed's traders was temporarily below zero, mostly because during those periods the predicted price difference was lower than the actual price difference, making it profitable with a zero risk premium --- the risk premia have to be negative to satisfy the condition that the 91-day cumulative profit equals to zero.



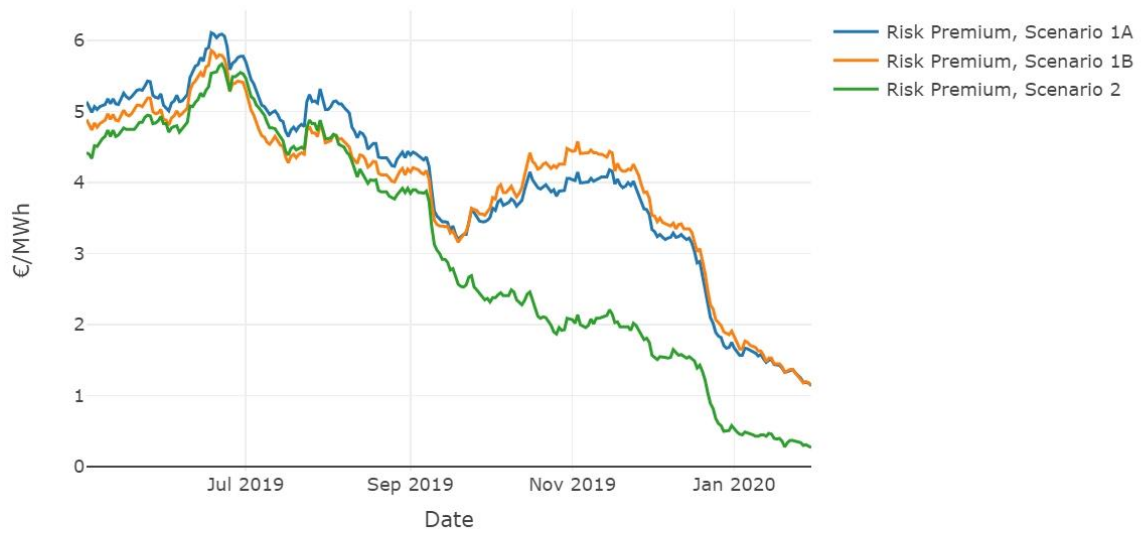


Figure A1 91-day Risk Premium, BritNed (upper) and Nemo (lower)

Finally, Figure A2 presents the 91-day-rolling standard deviations of hourly profit from trading in IFA and BritNed, where the risk premia are €1.32/MWh and €0.24/MWh, respectively. Similar to the Nemo example, we find the volatility of trading is much smaller under Scenario 2 than Scenarios 1A and 1B. Again, the sudden inclines (on 8th June 2019) and declines (91 days after 8th June 2019) are due to extreme prices.

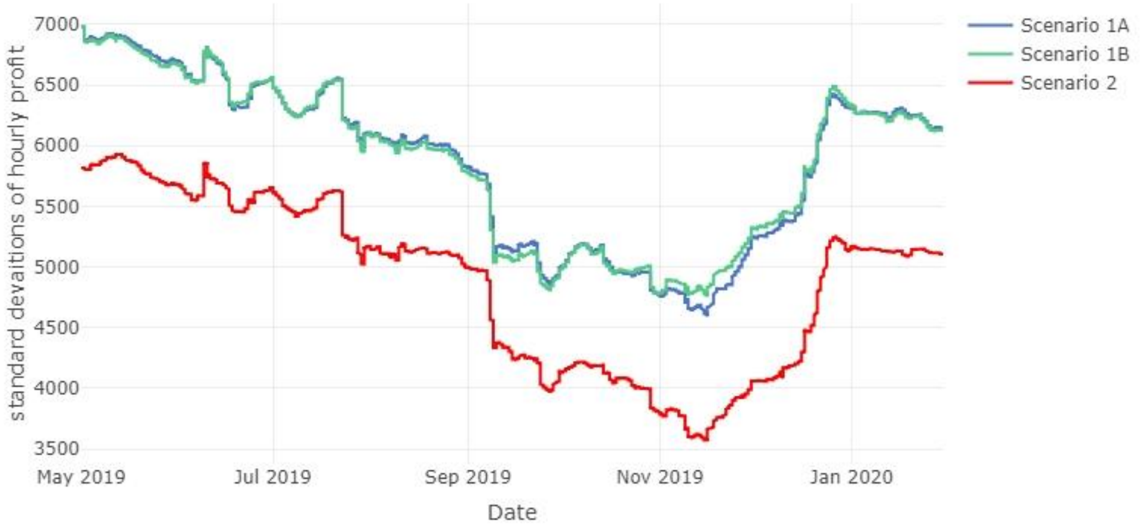


Figure A2 91-day-rolling Standard Deviations of Hourly Profit from Trading, BritNed (upper) and Nemo (lower)

Appendix B

TRADE AND COOPERATION AGREEMENT BETWEEN THE EUROPEAN UNION AND THE EUROPEAN ATOMIC ENERGY COMMUNITY, OF THE ONE PART, AND THE UNITED KINGDOM OF GREAT BRITAIN AND NORTHERN IRELAND, OF THE OTHER PART at https://www.gov.uk/government/publications/agreements-reached-between-the-united-kingdom-of-great-britain-and-northern-ireland-and-the-european-union

p784: *ANNEX ENER-4: ALLOCATION OF ELECTRICITY INTERCONNECTOR CAPACITY AT THE DAY-AHEAD MARKET TIMEFRAME*

Part 1

1. The new procedure for the allocation of capacity on electricity interconnectors at the day-ahead market timeframe shall be based on the concept of “Multi-region loose volume coupling”.

The overall objective of the new procedure shall be to maximise the benefits of trade.
As the first step in developing the new procedure, the Parties shall ensure that transmission system operators prepare outline proposals and a cost-benefit analysis.

2. Multi-region loose volume coupling shall involve the development of a market coupling function to determine the net energy positions (implicit allocation) between:

(a) bidding zones established in accordance with Regulation (EU) 2019/943, which are directly connected to the United Kingdom by an electricity interconnector; and

(b) the United Kingdom.

3. The net energy positions over electricity interconnectors shall be calculated via an implicit allocation process by applying a specific algorithm to:

(a) commercial bids and offers for the day-ahead market timeframe from the bidding zones established in accordance with Regulation (EU) 2019/943 which are directly connected to the United Kingdom by an electricity interconnector;

(b) commercial bids and offers for the day-ahead market timeframe from relevant day-ahead markets in the United Kingdom;

(c) network capacity data and system capabilities determined in accordance with the procedures agreed between transmission system operators; and

(d) data on expected commercial flows of electricity interconnections between bidding zones connected to the United Kingdom and other bidding zones in the Union, as determined by Union transmission system operators using robust methodologies.

This process shall be compatible with the specific characteristics of direct current electricity interconnectors, including losses and ramping requirements.

4. The market coupling function shall:

(a) produce results sufficiently in advance of the operation of the Parties’ respective day-ahead markets (for the Union this is single day-ahead coupling established in accordance with

Commission Regulation (EU) 2015/1222[22]) in order that such results may be used as inputs into the processes which determine the results in those markets;

(b) produce results which are reliable and repeatable;

(c) be a specific process to link the distinct and separate day-ahead markets in the Union and the United Kingdom; in particular, this means that the specific algorithm shall be distinct and separate from that used in single day-ahead coupling established in accordance with Regulation (EU) 2015/1222 and, in respect of commercial bids and offers of the Union, only have access to those from bidding zones which are directly connected to the United Kingdom by an electricity interconnector.

5. The calculated net energy positions shall be published following validation and verification. If the market coupling function is unable either to operate or to produce a result, electricity interconnector capacity shall be allocated by a fall-back process, and market participants shall be notified that the fall-back process will apply.

6. The costs of developing and implementing the technical procedures shall be equally shared between the relevant United Kingdom transmission system operators or other entities, on the one side, and relevant Union transmission system operators or other entities, on the other side, unless the Specialised Committee on Energy decides otherwise.

Part 2

The timeline for the implementation of this Annex shall be from the entry into force of this Agreement, as follows:

(a) within 3 months – cost benefit analysis and outline of proposals for technical procedures;

(b) within 10 months – proposal for technical procedures;

(c) within 15 months – entry into operation of technical procedures.

[22] Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (OJ EU L 197, 25.7.2015, p. 24).

Appendix C JAO bidding rules

Article 27 Bids submission

1. The Registered Participant shall submit a Bid or set of Bids to the Allocation Platform in accordance with following requirements:

(a) it shall be submitted electronically using the Auction Tool …

(c) it shall identify the direction for which the Bid is submitted;

(d) it shall state the Bid Price, which shall be different for each Bid of the same Registered Participant unless otherwise provided for in the Information System Rules, exclusive of taxes and levies, in Euros per MW for one hour of the Product Period, i.e. Euro/MW and hour, expressed to a maximum of two (2) decimal places, and equal to or greater than zero; …

(e) it shall state the Bid Quantity in full MW which must be expressed without decimals, minimum amount of a single Bid is one (1) MW.

2. The Registered Participant may modify its previously registered Bid or set of Bids at any time during the Pre-bidding and/or Bidding Period including its cancellation. In case the Bid has been modified only the last valid modification of the Bid or set of Bids shall be taken into account for the provisional Auction results determination. …

Article 32 Auction Results Determination

1. After the expiration of the Bidding Period for an Auction and the Credit Limit verification pursuant to Article 31, the Allocation Platform shall determine the Auction results and allocate the Transmission Rights in accordance with this Article.

2. The Auction results determination shall include the following:

(a) determination of the total quantity of the allocated Transmission Rights per direction;

(b) identification of winning Bids to be fully or partially satisfied; and

(c) determination of the Marginal Price per direction.

3. The Allocation Platform shall determine the Auction results using an optimization function aiming at maximization of the sum of the Registered Participants' surplus and the Congestion Income generated by the winning Bids while respecting the constraints of the optimization function in form of relevant Offered Capacities. The Allocation Platform shall publish additional explanatory information on the optimization function of the algorithm on its website.

4. The Allocation Platform shall determine the Marginal Price per direction based on the following criteria:

(a) if the total quantity of Cross Zonal Capacity for which valid Bids have been submitted is lower than or equal to the relevant Offered Capacity for the relevant Auction, then the Marginal Price shall be zero;

(b) if the total quantity of Cross Zonal Capacity for which valid Bids have been submitted exceeds the relevant Offered Capacity for the relevant Auction, the Marginal Price shall be set at the lowest Bid(s) Price(s) allocated in full or in part using the respective Offered Capacities.

Appendix D Worked examples of contracting

Contract decision making

Consider a generator in France selling a 1 MW baseload CfD one month ahead for a given strike price s_m, ($m = FR, GB$) where the subscript m indicates the country of the relevant market. Selling to a French buyer the contract would just be a simple CfD (s_{FR}, p_{FR}), where for the generator to be willing to sign the CfD, the strike price must be above the avoidable generating cost, c, so $s_{FR} > c$. A baseload CfD pays the generator Σ_h (s_m - p_{mh}) each day where p_{mh} is the DAM hourly price in hour h, h = 1,2,..H, and H is the number of settlement periods in the day. The standard CfD requires the buyer facing a price below the strike price to pay the seller, and the seller facing a price above the strike price to make up the difference to the buyer. It removes all price risk from the generator, and similarly for a consumer wanting a constant rate of supply every hour, but this risk reduction likely comes at some cost to one or other party.

In a world of perfect foresight, s_m would be the average of the hourly prices, $p_m = 1/H \Sigma_h p_{mh}$, for the duration of the CfD (which for convenience we can take as a day to avoid extra notation). If consumers are more risk averse than generators, $s_m > \text{E}p_m$, making it doubly attractive for well-capitalised low-cost reliable generators to sell forward CfDs.

Over the course of the day the DAM reference hourly price will vary and so will these payments between the parties. While the generator may be happy to run at a constant rate, the buyer will likely need to trade in the DAM to match his demand profile. Selling from BE to GB under SDAC would require a GB CfD (s_{GB}, p_{GB}) and a PTR in a month-ahead PTR auction at a price per MW of v_{FtG}. At each end the DAM hourly prices p_{mh} are determined by EUPHEMIA.

We can now consider the various cases to see how well various hedging contracts can alleviate risk. In particular, the generator has to decide whether to generate on the day in each hour, h, depending on whether p_{FRh} > *or* < c, and could nominate the PTR on IFA, but does not have to as un-nominated PTRs are automatically settled at the positive price difference.[23] The attraction of coupling is that it simplifies generation and purchase decisions. The decision to buy in GB is left to the buyer who submits a buy order into the DAM, while for the generator, the PTR becomes an FTR, and he just submits his offer to the DAM at avoidable cost, c. However, the fact that the PTR is an option means that it only offers insurance for flows from the generator to the consumer. To simplify, assume that (as is normally the case) FR on average exports to GB so that $p_{GB} > p_{FR}$ on average. When $p_{GhF} > p_{FRh}$, the PTR from BE to GB is in the money and offsets the requirement to pay p_{GB} - p_{FR}, while if $p_{GBh} < p_{FR}$ the PTR has zero value and does not offset the GB price risk.

To probe the pricing of PTRs more carefully, consider the case of perfect foresight, where $v_{FtG} = 1/H\ \Sigma_h$ Max(0, $p_{GBh} - p_{FRh}$) and $v_{GtF} = 1/H\ \Sigma_h$ Max(0, $p_{FRh} - p_{GBh}$), where H is the number of hours (or periods). It is convenient to have an hourly value for PTRs, so define v^+_{FtGh} = Max(0, $p_{GBh} - p_{FRh}$), where the + sign is a reminder that it is only positive values that count. The DAM hourly price differences $p_{GBh} - p_{FRh} = v^+_{FtGh} - v^+_{GtFh}$. The daily average

[23] The generator may prefer to generate even if the hourly price is below the apparent variable cost, as closing down and restarting are costly. We ignore these complications.

price difference is then $1/H\ \Sigma_h(v^+_{FtGh} - v^+_{GtFh}) = v_{FtG} - v_{GtF}$. Similarly, $s_{GB} - s_{BE}$ gives a prediction of the expected daily average price differences, and in a well arbitraged forward market we would expect both to be close to each other.

In the absence of perfect foresight, $v_{FtG} = 1/H\ \mathrm{E}\Sigma_h\ v^+_{FtGh} + r$, where E is the expectation operator, and r is the risk premium (positive or negative depending on the prevalence of buyers or sellers, and their risk aversion). Pricing individual PTRs requires a forecast of hourly prices if flows reverse, and unfortunately the observable CfD strike prices in the two markets only give the daily averages. If flows are assured to be in only one direction, then matters simplify and the value of the PTR will be the (observable) difference in strike prices. As a reminder the notation is:

c:	avoidable cost of generation, (this and all prices in €/MWh)
s_{GB}, s_{FR}:	strike prices in GB or FR (in CfDs signed ahead of delivery)
p_{GBh}, p_{FRh}:	price in the SDAC DAM in GB or FR in hour h.
p_{GB}, p_{FR}:	daily average price in SDAC DAM
v_{FtG}, v_{GtF}:	price of a baseload PTR contract secured in a month-ahead PTR auction

Case 1 Generation economic, $p_{FR} > c$, and the generator informs the French System Operator that she will generate.

Generator profit in each case from generating 1 MW in each hour is

c) Selling to BE consumer hedged with CfD: Profit = $1/H\ \Sigma_h[(s_{FR} - p_{FRh}) + (p_{FRh} - c)]$, where the first term is the profit on the CfD and the second is the profit from generating in each hour h. This simplifies to $s_{FR} - c$.

d) Selling to GB consumer hedged with a CfD in GB and buying a PTR from FR to GB at month ahead: Profit = $1/H\ \Sigma_h\ [(s_{GB} - p_{GBh}) + \{\mathrm{Max}(0, p_{GBh} - p_{FRh}) - v^+_{FtGh}\} + (p_{FRh} - c)]$, where the second term {} is the profit from allowing the PTR to become an FTR. If in every hour $p_{GBh} > p_{FRh}$, profit simplifies to $s_{GB} - v_{FtG} - c$ (without needing perfect foresight of the DAM prices).

If these are perfectly arbitraged:

$$s_{FR} = s_{GB} - v_{FtG}.$$

However, in most cases there will be hours of reverse flow and the term in {} will not cancel with the other terms. Suppose $p_{GBh} > p_{FRh}$ in hours h^* and $p_{GBh} < p_{FRh}$ in hours h^{**}, then profit will be

$$1/H\ \Sigma_h\ [s_{GB} - v_{FtG} - c] + 1/H\ \Sigma_{h^*}\ [(p_{GBh} - p_{FRh}) - (p_{GBh} - p_{FRh})] - 1/H\ \Sigma_{h^{**}}(p_{GBh} - p_{FRh}).$$

As before, in expectation

$$s_{BE} = s_{GB} - v_{FtG} + 1/H\ \Sigma_{h^{**}}(p_{FRh} - p_{GBh}).$$

Generators pay less for the PTR but are left with residual price difference risk in some hours.

Case 2 Generation uneconomic, $p_{FR} < c$, generator does not run.

Generator profit is

e) Selling to BE consumer hedged with CfD: $s_{FR} - 1/H\ \Sigma_h\ p_{FRh}$,

f) Selling to GB consumer hedged with a CfD in GB, buying a PTR from BE to GB at month ahead, and receiving (p_{GBh} - p_{FRh}) in trading hours h^*: $1/H \sum_h [(s_{GB} - p_{GBh} - v_{FtG}) + 1/H \sum_{h^*}(p_{GBh} - p_{FRh})$. Note that if $p_{FRh} < c$, profit in case c) is higher than in case a).

As before, in expectation

$$s_{FR} - 1/H \sum_h p_{FRh} = s_{GB} - v_{FtG} + 1/H \sum_h (p_{FRh} - p_{GBh}) - 1/H \sum_{h^*} (p_{FRh} - p_{GBh}) .$$

The last two terms give $1/H \sum_{h^{**}}(p_{FRh} - p_{GBh})$ as before, giving the same result and so we can ignore cases in which generators are not profitable.

Other contracts for hedging across borders

The problem with PTR (and FTR options) is they leave some price risk in forward markets, but this need not be the case, if there were an appetite for a new hedging contract. According to Meeus and Schittekatte (2018) the Nordic electricity market has its own CfDs which hedge price differences between the local area and the system price, called the 'electricity price area price differentials' (EPAD). "To hedge the price difference between two adjacent bidding areas with EPADs as an FTR would do, a combination of two EPAD contracts (a so-called EPAD Combos) needs to be acquired by a market player. Two EPAD Combos are required to cover the hedge 'both ways' for each interconnector between two bidding zones."

However, the problem with EPADs is that for many interconnectors, the average prices in their respective countries may be systematically different, as with the Continent where prices are typically below those in GB. In such cases there would likely be an excess of buyers in GB and sellers in FR, BE, NL (and the IEM generally), and as such there would need to be a counterparty to take on the basis risk.[24] The natural counterparty is the interconnector owner, for which the right contract is a Transmission Right. This is apparently a reason by EPADs are very illiquid, even in a market where at least some cross-zonal flows may be more balanced.

Clearly, if there were sufficient support, it would be possible to devise such CfDs across borders, with the advantage that as the standard CfD is an obligation, such CfDs could replicate the missing FTR obligations, without having to involve the interconnector owners. However, they would likely suffer from the illiquidity noted in the Nordic markets, and while avoiding the need for the agreement of interconnector owners, they do so at the risk of losing the natural counterparty to the basis risk. And if the interconnectors were to become involved in improving cross-border hedging, the simplest solution would be to have firm (obligated) FTRs. Indeed, it is clear from the lengthy discussions in the Nordic markets,[25] that there is a reluctance to move from EPADs to firm FTRs, so it would be perverse to introduce an inferior instrument that might block a superior one. There is also the obvious point that EPADs do not handle the allocation of interconnector capacity, for which the owners are the default counterparty, so they only solve part of the problem of cross-border trading.

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[24] We are indebted to Andrew Claxton for this observation.

[25] E.g. see *Financial Power Trading Nordreg Workshop on FCA GL* given by Bernd Botzet, Market Manager, Financial Market, Nasdaq OMX Oslo ASA on 10 May 2016