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The cost of uncoupling GB interconnectors

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Keywords Electricity trading, Market coupling, auctions, price forecasting

JEL Classification F14; F15, Q47; Q48; L94

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The cost of uncoupling GB interconnectors[1]

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Abstract
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 *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 article 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 discounts for each. The current timing leads to lower mistakes on the direction of flows, arguing for retaining 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. The social cost of uncoupling is €28 million/yr., considerably below earlier estimates in the literature. Experience since uncoupling validates this finding.

1. Introduction

On 1st January 2021 the United Kingdom (UK) ended the transition period of exiting the European Union (EU) and started trading under the *Trade and Cooperation Agreement,* TCA[4]).[5] Until that date, Great Britain traded electricity under the EU Integrated Electricity Market (IEM) arrangements designed to facilitate electricity trade over interconnectors joining different countries. Northern Ireland (NI) and the Republic of Ireland (RoI) continue trading electricity in the all-island 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 TCA. The consequences of Brexit on the British electricity sector are well documented

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

(e.g. Aurora Energy Research, 2016; Vivid Economics, 2016; Froggatt et al., 2017; Mathieu et al., 2018; Pollitt, 2017; Pollitt and Chyong, 2017).

This article 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 the social cost of uncoupling. By comparing different possible timings of auctions for interconnector capacity and domestic demand, the article considers whether a relatively simple reform to the order of these markets would improve efficiency. There is a deadline of March 2022 to implement new "loose coupling" trading arrangements, and this article argues for additional changes to improve their efficiency. While the bulk of this article was written before uncoupling, we are able to use recent data to compare our predictions and methodology with at least the first few months' experience.

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 for the case between GB and the Continent). 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 GB's generation fuels) distorted trade over interconnectors, and calculated the impacts on prices in GB and its neighbours, as well as the impact of asymmetric carbon prices on carbon leakage, the deadweight loss and the impact on interconnector revenue. This article ignores the complexity of asymmetric carbon taxation as the post 2021 carbon prices facing electricity are almost the same, despite Brexit. In large part this is because of reforms to the EU Emissions Trading Scheme (cancelling surplus allowances) and the growing acceptance that the EU's commitment to net zero by 2050 is credible. By July 2021 the EUA price as €57/tonne CO_2, while the first UK carbon auction cleared in June 2021 at £50/t and then traded at £45 (€53)/t.

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) reviewed related literature and summarised that the economic benefit of GB integrating with the Continent to be £100 m./year or more in the short-term, representing the economic loss when the market integration between the two was undone. Geske et al. (2020) looked at the consequences of a hard Elecxit (i.e., uncoupling with no substitute trading arrangements) in a high-renewable 2030 scenario with 10 GW of interconnector capacity between GB and France, and estimated that GB's and French generator costs would increase by €692 m/yr, a measure of the welfare loss.[6] Newbery (2020), in his comment on that article, argued that this was an overly pessimistic estimate as it ignored arbitrage opportunities that would substantially lower the cost.

Despite the differences due to estimation techniques (simulation or regression or both), scenarios considered (2012-2014 *vs.* 2030) and data (realised *vs.* predicted data), these earlier estimates suggest that the costs of uncoupling can be substantial. Fortunately, the TCA that the UK has negotiated with the EU should reduce the costs of the more pessimistic forecasts.

In this article, we implement a different method to estimate the immediate costs for three interconnectors: to France (FR) via IFA, The Netherlands (NL) via BritNed, and Belgium (BE) via Nemo. We describe how traders could forecast interconnector price differences to guide their bids in an explicit auction for capacity. For the most part this is based on price data of previously coupled markets, as we have at the date of writing only very limited data for the uncoupled period. The structure of the regressors reflects differences in information resulting from different trading arrangements. With the forecast, uncoupled trade flows are simulated and welfare losses determined. We also compare our simulated results with the uncoupled period to test the validity of our estimates. Section 6 assesses possible improvements to the final implementation of the TCA.

Under the TCA, the System Operators (SOs) in GB and those in countries interconnected to GB (France, Netherlands, Belgium and the SEM) need to develop new trading arrangements based on "Multi-region loose volume coupling", with a timetable of entry into operation within 15 months. 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 the efficient use of interconnectors, but also in facilitating contracts to reduce the risk of trading. Generators sell their output on terms that balance 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 be hedged on various markets and/or self-hedged by signing up customers and integrating into retailing.

[6] 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).

The question addressed in this article 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 TCA's proposed 'Multi-region loose volume coupling' to include firm Financial Transmission Rights. Section 7 concludes with policy recommendations.

2. The impact of 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 *Clean Energy Package*) and if electricity wholesale markets are workably competitive (as they are in GB), then market prices would correctly measure the social cost of generation. World Bank (2019) argued that the 2020 Paris target-consistent price was at least US$40–80/t$CO_2$. We assume efficient carbon pricing as in the EU and UK, carbon prices facing electricity are target-consistent at over €50 ($60)/tonne by June 2021, within the World Bank range. 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 sometimes to bid to flow in the wrong direction. Lower prices for capacity and incorrect 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 imports from the lower cost country are replaced by costlier domestic generation. If the coupled price differences in any hour were d, and after uncoupling in that hour are $\tilde{d}$, and if the reduction in trade is ΔV, the increase in social cost is $1/2 \cdot \left(d + \tilde{d}\right) \cdot \Delta V$, where ΔV may have to take account of a change in direction of trade. d is observed, and $\tilde{d}$ can be estimated using the methodology and results of Guo and Newbery (2020). The key element in these calculations is to estimate ΔV 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. Suppose the interconnector has capacity C = 2,000 MW, with possible price differences, d, of €4, €3, €1, -€4, (for example, between GB and FR, 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 (i.e. €2,000). 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 article, erring on the side of overestimating costs, the assumption is that actual nominations are based on the original forecasts of price differences. Figure 5 below shows that the flows observed since uncoupling suggest similar inefficiencies experienced before coupling in 2014, and confirm that traders appear more cautious and also sometimes do nominate unprofitable trades.

We address these risks by reducing traders' unbiased forecast of the price difference across the interconnector by a "risk" discount. In practice sometimes it will be less costly not to nominate unprofitable trades and accept imbalance charges, 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 by our method.

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. Larger and better endowed companies are able to take riskier positions, or require a lower risk discount 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 low prices benefit retailers but harm generators. This risk complementarity provides the motivation for them to sign contracts or vertically integrate and avoid market exposure.

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 move with 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.

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 $(s-p)\cdot M$ and the buyer pays $(s-p)\cdot M$, 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, as in the Single Electricity Market (SEM) of the island of Ireland.

3.1 Trading and hedging over interconnectors

Single Day Ahead Coupling (SDAC) solved one critical problem – that of inefficient trading on interconnectors, but did not in itself solve the problem 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 may 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[7] they cannot issue both PTRs and FTRs at the same bidding zone border (FCA, Art. 31(6)).[8] Under the SDAC, GB only used PTRs with the Continent, but the two interconnectors with the SEM issued 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 create 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

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

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

considerable advantages in choosing obligations rather than options for hedging, as argued below.[9] They bring more competition to bear in each market as they allow netting of trades on interconnectors,[10] 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.

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-sided 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 (i.e. an equal volume in every hour of the day), 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. Agents can respond to later information (outages, updated wind forecasts, etc.) by trading in Intraday Markets (IDMs), and finally in the Balancing or Real-time Market. Thus 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). The liquidity of these markets is critical for the efficient working of an unbundled and liberalised electricity market.

Trading across interconnectors in forward markets has similarities (typically baseload for varying durations) but important differences, in that the PTR of price differences 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 why traders dominate interconnector trade. Appendix B 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 are not able to participate in the EUPHEMIA EU-wide auction platform.[11] The island of Ireland is in a special

[9] 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 articles arguing for such obligations (e.g. O'Neill et al., 2002).

[10] 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.

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

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.[12] The SEM is no longer coupled at the Day-ahead stage but remains coupled in the intra-day markets (in contrast to GB which is completely uncoupled). Nemo Link (to Belgium) already has in place a set of Non-IEM Access Rules that have been approved and are operational from 1st January 2021. Ofgem also published its guidance on all GB links.[13] The individual interconnectors have published the day-ahead timings. Figure 1 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).

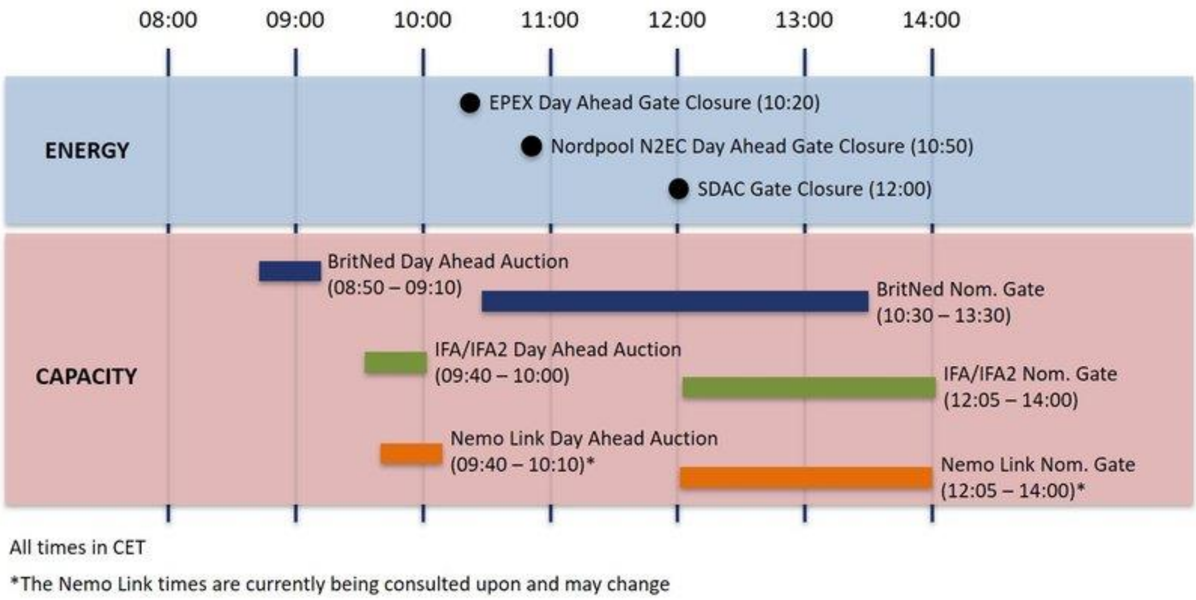

Figure 1 Overview of GB Day Ahead Auctions
Source: BritNed at https://www.britned.com/brexit/auctions/

The rules for explicit auctions are set out on the Joint Allocation Office (JAO) website.[14] This article considers two auction designs – the default JAO design 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.

[12] At https://www.semcommittee.com/news-centre/sem-committee-statement-operation-sem-after-end-brexit-transition-period
[13] At https://www.ofgem.gov.uk/about-us/ofgem-and-europe/brexit-and-transition-period
[14] At https://www.jao.eu/support/resourcecenter/overview

4.1 The JAO explicit auction

Actors submit hourly bids to the explicit auction for the option to use the interconnector in a given direction. The bids provide an implicit 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, traders will bid for capacity in both directions at a positive price as the option likely still has some value. Bids are summed in each direction up to full capacity and the direction that gives the highest congestion revenue determines the direction to provide to the SDAC DAM. Appendix B provides examples of how these rules affect generators trading across borders. Different trading strategies involve varying degrees of price risk exposure, compared to just trading domestically hedged with CfDs. The conclusion is that traders (or the trading arms of diversified utilities), who are reasonably risk-tolerant and good at forecasting, will be the main arbitrageurs. Stand-alone generators will sell domestically, on the assumption that traders have already arbitraged away any risk-adjusted profits from exporting.

5. **Empirical estimates of 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. Bidders will be cautious in paying for capacity and risk exposure to the possibly onerous charges of unwinding their position in balancing markets, as selling requires a prior commitment to deliver there. One key risk is the interconnector importing from a high price country into a low cost country, and the resulting Flow Against Price Difference (FAPD) will cause losses that need to be addressed by more cautious bidding, subtracting a risk discount from the forecast price difference. The resulting risk discount will reduce interconnector congestion revenue. This reduced revenue will have additional costs if it discourages potentially profitable investment in future interconnectors. This reduced revenue can be considerable: a €1 of discount to fair value if the interconnector is available for 8,000+ hrs/yr. is worth €8+ million/yr. on a 1,000 MW interconnector.

The rest of this section describes the methods for forecasting the price differences between GB and other Continental countries connected with GB, and then compares the forecast accuracy of different forecast rules. The best forecast method is then used to estimate traders' risk discount under different trading rules after Brexit, 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.

5.1 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 the Continental (i.e., FR, NL or BE) prices, or effectively, their price difference (GB *minus* the Continental price), to inform the bid and direction. We compare the three most common econometric methods with a naïve method for forecasting the price differences between GB and the three connected countries.[15] We consider first just forecast the DA hourly prices for connected markets and then take the difference.

The *Naïve Forecasting Method* (NFM) sets the forecast of DA hourly prices equal to prices one-day (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 seven-days (168 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 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

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

where m represents AR lags, $X_{j,t,h}$ contains exogenous variables including DA forecasts of domestic and foreign electricity demand and renewable generation (including GB, NL, BE and Germany[16]), 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 correlations of prices among different hours within a 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 as in (3). 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, hence their coefficient matrices are also diagonal.

[15] Machine learning methods such as Artificial Neutral Networks and Support Vector Machines were also attempted, but their forecast errors were much greater than the proposed econometric methods and they are not considered further. Spot market forecasting is also discussed in Keles et al. (2016), Mirakyan et al. (2017), Marcjasz et al. (2020).

[16] Germany is included as it is heavily interconnected with FR, NL, and BE.

Equations (1) - (4) provide forecasts of DA prices. The forecasted Continental prices are subtracted from the forecasted GB prices to give a forecast of 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 the Continental market.

If the GB DA market timing were changed to clear before the explicit auction, it would only be necessary to forecast the Continental price to predict the price difference. In this case, GB's market clearing prices are included in regressions (2)-(4) as predictive variables.[17] We test to see if that improves efficiency and reduces the social loss of uncoupling as a change in market and auction timing might be relatively simple to introduce. To anticipate the results reported below, we find that the present timing is superior so there is no need to make that change.

Although our forecast of prices is estimated based on the coupled market, there is no reason to think that the underlying determinants of DAM prices will be materially different in the uncoupled markets, as each DAM (in GB and the SDAC on the Continent) will take expected trade into account, and we find that the change in trade is small compared to the relevant market demands. We comment further on this when discussing the proposed multi-region loose volume coupling that attempts to make trade volumes explicit in the SDAC. While it may be possible to improve forecasts by taking more factors into account, that will only improve on our current estimates. Our central point is that even if we over-estimate the costs of uncoupling, it is still substantially lower than the earlier estimates by other researchers.

5.2 Data

GB's DA electricity prices in Euros come from the Nord Pool, and the DA electricity prices for FR, NL and BE come from the ENTSO-E transparency platform. The day-ahead forecasts for renewable generation and demand are collected from the ENTSO-E transparency platform.[18] 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).

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*.[19] Finally, the daily auction price for CO_2 - the EU Allowance price - comes from Bloomberg. When

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[17] In this case forecasting the Continental price and forecasting the price difference is identical, as the GB price enters to the right-hand-side of regressions.

[18] 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.

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

calculating the congestion revenue, 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 and ENTSO-E Transparency Platform. The cut-off date was determined by data available at the time of writing, but there is no reason to limit the period to the pre-uncoupling period, as price setting within each country or region should not be materially affected by uncoupling. Later on we explore the uncoupled period to check that our forecast results are supported by the (limited) data available since Jan 2021.

5.3 Forecasting process

Unexpected events such as nuclear outages and extremely cold winter days can cause extreme prices driven by high demand and/or low supply. We find that including previous extreme prices as predictive variables can distort the values of estimated coefficients, resulting in poor forecast accuracy (not reported). Hagfors et al. (2016) argued that extreme prices cannot be predicted by conventional econometric methods, and probability models are preferred as instead. 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.

As the youngest interconnector among the three, Nemo was commissioned on 31st Jan 2019, hence for all three interconnectors we collect data from 31st Jan 2018 to 30th Jan 2020. Data for the first 365 days are used for in-sample training (i.e., estimating the model) and the data for the second 365 days are used for out-of-sample validation (i.e. using the estimated coefficients to forecast).[20] 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.

5.4 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 $d_{t,h}$, the MAE is

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

and the MSE is

[20] We also attempted to set a smaller training set of 91 days. The result shows that a smaller training set does not improve forecast accuracy, consistent with Fezzi and Mosetti (2020).

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

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.

While MAE and MSE estimate the accuracy of forecasts, *Flows Against Price Difference (FAPD),* is the standard ACER metric of interconnector inefficiency. It measures the percentage of time that the interconnector flows from the higher-price to the lower-price market, or equivalently, that the sign of the predicted price difference differs from that of the actual price difference. The FAPD is

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

5.5 Identifying the optimal forecast

We consider three different scenarios. In the first two (the current arrangement), neither GB's nor the Continental 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: the DA forecast of GB and the corresponding Continental electricity demand. Scenario 1B forecasts GB and the Continental DA prices separately and then takes their difference. In Scenario 2, modelling a relatively simple reform, the GB DA hourly market clears before the interconnector auction.

Table 1 presents the error measures of forecast results on the price difference between GB and FR. The cases for BritNed (GB-NL) and Nemo (GB-BE) are not reported but tell a similar story. 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 lower FAPD. In Scenario 2, as traders know the GB price before making predictions, one may expect them to make better prediction of the price difference. This is indeed the case as we find smaller MSEs and MAEs for all forecast methods implemented. One might naively expect that knowing one price halves the forecast error, and that is roughly what happens with the Mean Squared Error. However, this does not necessarily mean that a better forecast on *relative values* of price differences is associated with a better forecast on the *sign* of price differences. The intuition is that due to its (much) higher carbon pricing during this period, the DAM price in GB is usually higher than those in the Continent. However, when the capacity utilization rate of the Continental electricity system is high, the GB price might be lower. In this case, knowing the GB price would give little information on the sign of the price difference, and from our estimates, this can distort forecast accuracy.

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 (GB-FR)

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 both Scenarios 1, both GB and FR DA prices are unknown. In 1A the price difference is forecasted; in 1B the DA prices are forecasted to give their difference. In Scenario 2, the GB DA price is revealed before the auction, and the price difference is forecasted using the GB DA price as a predictor.				

5.6 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 or bid discount to account for the cost of unwinding or accepting unprofitable trades, and calculate the annual (and quarterly) 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, we denote the risk discount 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

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

and the marginal traders' profit for that hour is:

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

$\Pi = 0$ when $-r < \hat{d} < r$, where marginal traders do not participate in the explicit auction.[21]

For example, suppose traders' risk discount is €1/MWh. If the forecast of GB-FR price difference is €10/MWh, they would bid €9/MWh in the explicit auction. If the DAM clearing price difference is negative or greater than €9/MWh, traders lose, otherwise they make a profit. The profit (and losses) from trading (for each hour) are cumulatively summed and periodically checked. If traders hardly ever make a cumulative loss then rerun the calculations with a lower risk discount of, for example, €0.5/MWh, with bids of €9.5/MWh in the explicit auction, and so on. Eventually, when the traders' cumulative profit (over a year) is close to zero (representing a very competitive trading market), the corresponding risk discount is taken as the risk discount of the marginal traders.

From formula (6), the traders' loss comes from forecasting the wrong sign of the price difference or overestimating the price difference. Figure 3 presents a scatter plot between the actual GB-FR price difference and the forecast values using ARX in Scenario 2. The dots distribute evenly around the 45-degree line. Only a small proportion of dots are within the second and fourth quadrants, indicating most of the forecasts are of the right sign. As a result, traders' losses come mainly from overestimating the price difference (instead of forecasting a wrong sign).

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[21] Although marginal traders do not participate, infra-marginal traders may, resulting in some flows in this case. They would on average make losses and eventually presumably leave the market, but see Section 5.7 below.

Figure 3 Actual *vs*. Forecast GB-FR Price Differences using ARX under Scenario 2

The results in Table 1 assume marginal traders make forecasts using the ARX method. We consider the three different scenarios described above. If these traders are risk-neutral and competitive, the risk or bid discount will be bid down to drive average profits towards zero. Table 2 presents the discount that allows marginal traders to barely make a non-negative profit between 31st Jan 2019 and 30th Jan 2020 for IFA, BritNed and Nemo,[22] under the three different scenarios. It also reports the standard deviation of marginal traders' hourly profit over the year using the corresponding risk discounts. The standard deviation of hourly profit can be interpreted as a proxy for the volatility of trading, and risk-averse traders dislike volatile markets. In Scenario 2, marginal traders enjoy a much lower volatility of hourly profit. If risk aversion is a serious problem the discount for trading would need to be higher, and that might make a reordering of the timing of the explicit auction and the GB DAM attractive. However, in this article we assume traders are sufficiently risk-tolerant for the discounts and actions under each scenario to be as reported.

[22] It seems plausible that traders would frequently update their risk discount based on the trading result during the previous, for example, three months. Figure 1A in the Appendix presents the trader's dynamic risk or bid discount based on the trading results during the past 91 days.

Table 2 Zero-profit discounts for marginal traders with corresponding standard deviations of hourly profit.

		Scenario 1A	Scenario 1B	Scenario 2
IFA (GB-FR)	Discounts (€/MWh)	2.35	2.39	**1.32**
	Standard Deviation (€ thousand)	11.5	11.5	**8.3**
	Annual Profit (€ million)	0.10	0.06	0.09
BritNed (GB-NL)	Discounts (€/MWh)	0.85	0.75	**0.24**
	Standard Deviation (€ thousand)	6.9	6.9	**5.4**
	Annual Profit (€ million)	0.03	0.04	0.03
Nemo (GB-NL)	Discounts (€/MWh)	3.19	3.08	**2.33**
	Standard Deviation (€ thousand)	11.2	11.2	**10.0**
	Annual Profit (€ million)	0.03	0.01	0.03

5.7 The cost of uncoupling

The *Commercial Cost of Uncoupling* (CCU) is the loss in congestion revenue relative to the total congestion revenue under market coupling. Given observed net imports under market coupling ($V_{t,h}$) and the estimated net imports when uncoupled, the CCU is

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

where $\hat{V}$ 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.[23] $\dot{d}_{t,h}$ 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 $\hat{\theta}_{GB}$ for GB and $\hat{\theta}_C$ for country C,[24] $\dot{d}_{t,h}$ can be expressed as:

[23] More risk-tolerant traders may wish to buy more capacity and displace marginal traders, but this is a rough and ready way to model flows in this case, and hence overstates the potential losses (as with other assumptions).

[24] 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.

$$\dot{d}_{t,h} = d_{t,h} + (\hat{\theta}_{GB} + \hat{\theta}_C) \cdot (V_{t,h} - \hat{V}_{t,h}).$$

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:

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

The SCU is estimated under the standard assumption that the short-run demand is inelastic and that electricity wholesale market prices correctly measure the social cost of generation.

Table 3 Commercial and social costs of uncoupling

	Scenarios	CCU (€ m./yr.)	SCU (€ m./yr.)
IFA	1A	**18.3**	**15.6**
	1B	18.7	15.9
	2	23.7	20.0
BritNed	1A	**8.4**	**8.6**
	1B	8.8	8.9
	2	10.4	10.3
Nemo	1A	**4.1**	**3.3**
	1B	4.4	3.6
	2	6.0	5.2
Total	1A	**30.8**	**27.5**
	1B	31.9	28.4
	2	40.1	35.5

Table 3 presents the commercial and social costs from uncoupling IFA, BritNed and Nemo in the three scenarios, with bold indicating the least-cost options (which, agreeably, are the same scenarios for each interconnector). The total commercial cost of uncoupling is about €31 m./yr. under the current trading rule, while if the GB DAM price is revealed before the explicit auction (i.e., Scenario 2, the case preferred by traders), the commercial cost raises to €40 m./yr. The estimated social cost of uncoupling is about €28 m./yr. under the current trading rule, but can be as high as €36 m./yr. if the GB 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 1). 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 consistent with Newbery et al. (2016). The social costs are lower than the commercial costs as the commercial costs are evaluated at the equilibrium price and the social cost is reduced by infra-marginal values (the average of the initial and final price differences).

Regulators should be more interested in the social cost of uncoupling under different trading rules. Figure 4 presents the cumulative social cost of uncoupling for IFA, BritNed, Nemo, and the three interconnectors in total. In Scenarios 1A and 1B, the SCU for all three interconnectors is significantly below those in Scenario 2, and in total, the difference in the SCU of moving to Scenario 2 could be as high as €8 m./yr.

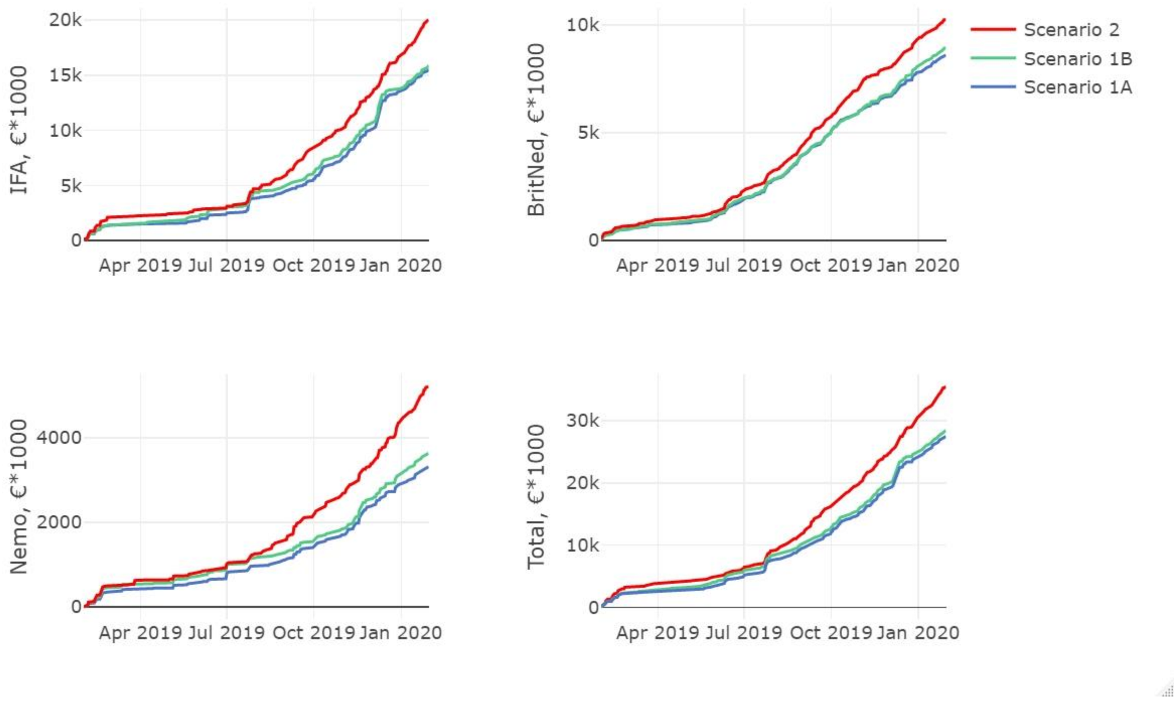

Figure 4 Cumulative Social Cost of Uncoupling for IFA, BritNed, Nemo, and in total.

6. The observed effect of the interim arrangements: the case for IFA

At the time of revising this article, the interim arrangement had been in operation for only a few months. Rather than undertake the (massive) task of updating all the original forecasts,[25] we use the most recent data under the interim arrangement and apply the same method as Section 5 to estimate the uncoupled price difference. The simulated uncoupled flow is then used to estimate the SCU and CCU. The estimated values are compared with the actual values to test the validity of our method.

[25] A full update would involve re-running 4 regression techniques, 3 trading scenarios, for 3 interconnectors, about 36 times more work than the modest check reported here.

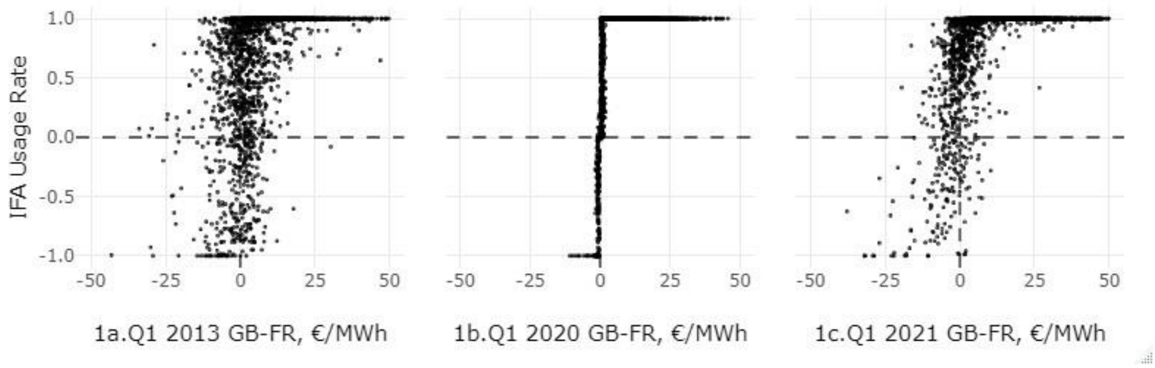

Figure 5 IFA's usage rate vs. price difference in Q1 2012, 2020, and 2021

Figures 5a, 5b, and 5c show the cross-border electricity trading for IFA during the first quarter of 2013, 2020, and 2021, with the horizontal axis representing the day-ahead price difference between GB and France, and the vertical axis representing the usage rate of IFA. When the usage rate is positive, the interconnector was used for importing, and *vice versa*. Price differences greater than €50/MWh are excluded from the figure. When the market is coupled (Figure 5b), the day-ahead trading is efficient, with flows moving from the lower-price to higher-price market; whereas before market coupling (Figure 5a) and under the interim arrangement (Figure 1c), the use of the interconnector is not fully efficient, with FAPD being observed.

Table 4 compares IFA's FAPDs and price differences during Q1-Q4 2013 (before GB entered SDAC) with Q1-Q4 2020, as well as Q1-Q2 2021. From Q2 2013, GB introduced an escalating Carbon Price Support (CPS) that taxed CO_2 emissions from electricity at a higher rate than on the Continent, resulting in a much higher GB DAM price than that on the Continent. As noted, this price difference had almost completely disappeared by May 2021. We find the price difference to be much more volatile in Q1 2021, mostly because in mid-January 2021, the GB DAM price reached above £1,000/MWh during peak hours due to high demand, low wind speeds, and fossil power plants under maintenance.

Table 4 Comparing IFA FAPDs and price differences (€/MWh) in 2013, 2020, with Q1 2021

Year	Quarter	Mean (GB-FR)	S.D. (GB-FR)	FAPD
2013	Q1	€8.48	€15.08	23.3%
	Q2	€24.37	€19.41	6.9%
	Q3	€18.73	€13.30	4.2%
	Q4	€11.67	€16.01	15.5%
2020	Q1	€8.61	€9.38	2.1%
	Q2	€9.32	€10.45	2.5%
	Q3	€1.20	€6.46	4.5%
	Q4	€10.46	€18.04	3.6%
2021	Q1	€20.19	€73.24	13.8%
	Q2	€20.83	€22.96	8.7%

We expect FAPD to be negatively related to the (absolute value of) the average price difference, and positively related to the standard deviation of the price difference. Therefore, by comparing Q2 2021 with Q2-Q3 2013 (as the price difference and the standard deviation of the price difference among the periods are similar), we can conclude that the observed FAPDs under the interim arrangement are similar to those before market coupling.

The next step is to use the best available data to simulate the interim arrangement outcome for 2021, and then compare the simulated outcome with the actual outturn. As we find no testable structural break on 1 Jan 2021 (not reported), we use the data between Q2 2020 and Q1 2021 as inputs, and then apply the ARX regression to forecast the price difference between GB and France in Q2 2021 on a 365-day-rolling basis.[26]

Table 5 reports the MAE, MSE, and FAPD for the forecasted price difference in Q2 2021. Comparing with Table 4, we observe some much higher MAE and MSE. This can be explained by the much greater volatility of price differences in Q1 2021 – using the Q1 2021 data to forecast the Q2 2021 price would substantially distort the forecast accuracy, even if

[26] One may argue that as the trading rule has changed since 2021, it might be more appropriate to use the Q1 2021 data as input to forecast the Q2 2021 outturn (i.e., on a 91-day-rolling basis). However, that will result in some higher forecast errors. Therefore, we stick with the original method that uses the previous 365-day data as model inputs. We use the ARX technique to forecast the price difference as it is the best forecast technique among the ones we examined (see Tables 1 and A1). Under the interim arrangement, there is no explicit auction before cross-border trading, therefore the GB price cannot be included as a predictive regressor.

we have dealt with those extreme prices. Fortunately, the estimated FAPD is consistent with Table 1 and the actual FAPD reported in Table 4.

Table 5 Error Measures for IFA Forecast (GB-FR), Q2 2021

MAE	MSE	FAPD
14.72	444.77	10.8%

Next, using the forecasted price difference, we find the minimum risk discount that allows the marginal trader to make a non-negative profit during Q2 2021. The estimated risk discount for Q2 2021 was 0.91, comparable with that for 2019 reported in Table 2.

The risk discount is used to simulate the uncoupled flow, which is then used in conjunction with the forecasted price difference to estimate the SCU and CCU. Table 6 reports the forecasted SCU and CCU, as well as the actual values in Q2 2021. Despite the more volatile GB prices in Q1 2021, our estimated values are consistent with our earlier estimates shown in Table 3. (Table 3 reports the annual total values whereas Table 6 reports the values for Q2 2021. In 2019 the maximum capacity for IFA was 2 GW whereas in Q2 2021 it was expanded to 3GW.) However, when comparing with the actual CCU and SCU, though the magnitudes are the same, our forecasted results are much greater. One explanation is that traders have access to more information at the day-ahead stage and better forecast techniques that can also efficiently forecast extreme prices (which happened a lot in 2021). Despite of the difference, our conclusions still hold – the cost of uncoupling might be substantially over-estimated in early research, and the arbitrage opportunity has indeed substantially lowered the cost.

Table 6 The estimated and actual commercial and social cost of uncoupling, Q2 2021, € million

	CCU €m./quarter	SCU €m./quarter
Forecasted values	7.85	7.98
Actual values	1.84	2.17

Our estimates also always err on the side of over-estimating costs, to avoid exaggerating the cost of uncoupling. If we multiply the estimates by four to give a full year and then by 2/3 to correct for the capacity increase, the CCU would be €20.9 m. (compared to €18.3 m. in Table 3) and €21.3 m. (€15.6 m.). Despite that, the over-estimated results are still lower than the estimation from the earlier doom-laden predictions.

7. 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. That would provide one more liquid market for buyers and sellers trading within GB 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.[27] 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. Whether this loose volume coupling provides much of an improvement over the interim arrangements is not clear, as it requires good forecasts of the flows between countries bordering GB's trading partners to anticipate the likely volume of bids and offers (and hence the market clearing price) in the EU SDAC auction.

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 TCA but nor is it prevented. Taking IFA as an example, 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);

Consider the case of a French generator wishing to hedge her 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 a) and case b) 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.

8. Conclusion and policy implications

The UK's departure from the EU and the end of the transition period on 1 January 2021 ended day-ahead market coupling. The TCA required the UK and EU System Operators to design and evaluate 'Multi-region loose volume coupling' or MRLVC. This would allocate capacity on the interconnectors to GB at the day-ahead stage, in time to deliver the results to the Continental SDAC auction, which would then determine market prices. At the time of the capacity

[27] See https://www.gov.uk/government/publications/agreements-reached-between-the-united-kingdom-of-great-britain-and-northern-ireland-and-the-european-union

allocation, MRLVC would only have available order book data for GB and be granted access to the order books for the bidding zones directly connected to GB. These order books should help forecast flows between the "bordering bidding zones" (BBZs) directly connected to GB (currently SEM, FR, BE, NL and shortly NO) and the rest of the Continental Integrated Electricity Market. If these are accurately forecast, then with the nominated flows from GB to the BBZs it should be possible to compute the SDAC DAM prices, but there is no available evidence on how accurately these flow forecasts will predict prices.

Much will depend on the quality of these forecasts, how they are used and on the detailed design of the MRLVC. CEPA (2021) has delivered a cost-benefit study of MRLVC as required by the TCA, but notes that key features, such as the accuracy of the BBZ flow forecasts, are unknown. Previous attempts at volume coupling have not been notably successful. According to Meeus (2011, p11) discussing the Kontek cable between Germany and Denmark "contrary to the expected, the "no coupling" implementation outperformed the "volume coupling implementation"." A simple view might be that adding additional information (BBZ flows) to the data that we have examined and which would still be available, ought to improve the forecast accuracy of prices in the SDAC, as would the improved liquidity of the combining the DAM and the (numerous) interconnector auctions.

CEPA (2021) also point out other obstacles to successfully introducing MRLVC. Agreeing the changed timings of the data flows, gate closure times and delivering the results in sufficient time requires multi-party cooperation, which has not been notable for its speedy delivery in the past. Indeed, the obviously mutually beneficial option of re-admitting GB to SDAC has clearly been stymied by politicians on both sides of the Channel. 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 €31 m./yr., or about 13% of the total congestion revenue under market coupling. The social cost of uncoupling is slightly lower at about €28 m./yr. The very limited data from Q1 2021 of the observed impact of uncoupling suggests that these may be over-estimates.

As traders are now 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 discount to their price forecasts. If 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 discount was estimated to be quite high at over €2/MWh. The initial bid discount on Nemo could be as high as €3/MWh, but improved market linking as time passed after commissioning reduced the discount to just over €1/MWh. The less volatile market in the Netherlands and longer period since commissioning results in a lower bid discount 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 volume coupling is to reduce the loss in congestion revenue and reduction in social benefit 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 taken after the explicit auction should improve efficiency by adjusting flows on interconnectors, reducing the costs of uncoupling. Further improvements such as FTRs and possible MRLVC should improve interconnector profitability and mitigated the discouragement to building further interconnectors, of which many are at the design stage.

Possibly a major benefit of MRLVC is that liquidity will be concentrated in a single GB DAM, improving risk management, enhancing competition, and lowering bid discounts, which should improve interconnector efficiency. Against that poor design and adverse early results of MRLVC might undermine the enterprise, as has happened with earlier volume coupling. The obvious solution is to return to proper market coupling as mutually beneficial. If not, then replacing PTRs with FTR obligations might offer an alternative route to more efficient trading, increased competition and hence an improvement in social welfare.

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Abbreviations

ARX	Autoregressive models with exogenous variables
CACM	Capacity Allocation and Congestion Management
CCU	Commercial Cost of Uncoupling
CfD	Contract for Difference
CPS	Carbon Price Support
DA	Day ahead
DAM	Day-ahead market
D-1	the day before (the delivery date)
ETS	Emission Trading Scheme
EU	European Union
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
FAPD	Flows Against Price Difference
FCA	Forward Capacity Allocation
FTR	Financial Transmission Right
IDM	Intraday Markets
IEM	Integrated Electricity Market
IFA	Interconnexion France Angleterre
JAO	Joint Allocation Office
LT	Long term
MAE	Mean Squared Error
MRLVC	Multi-region loose volume coupling
MSE	Mean Absolute Error
NFM	Naïve Forecasting Method
NI	Northern Ireland
PTR	Physical Transmission Right
RoI	Republic of Ireland
SCU	Social Cost of Uncoupling
SDAC	Single Day-ahead coupling
SEM	Single Electricity Market of the island of Ireland
SLR	Single Linear Regression
SO	System Operator
TCA	Trade and Cooperation Agreement with the EU that came into force on 1 Jan 2021
UK	United Kingdom
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%

Figure A1 plots the dynamic risk discount for a marginal trader based on the trading results during the past 91 days, when trading in the IFA, BritNed and Nemo explicit auction. For all interconnectors, the risk discount in Scenario 2 is almost always lower than those under Scenarios 1A and 2B. The risk discount 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 discount. The risk discounts have to be negative to satisfy the condition that the 91-day cumulative profit equals to zero.

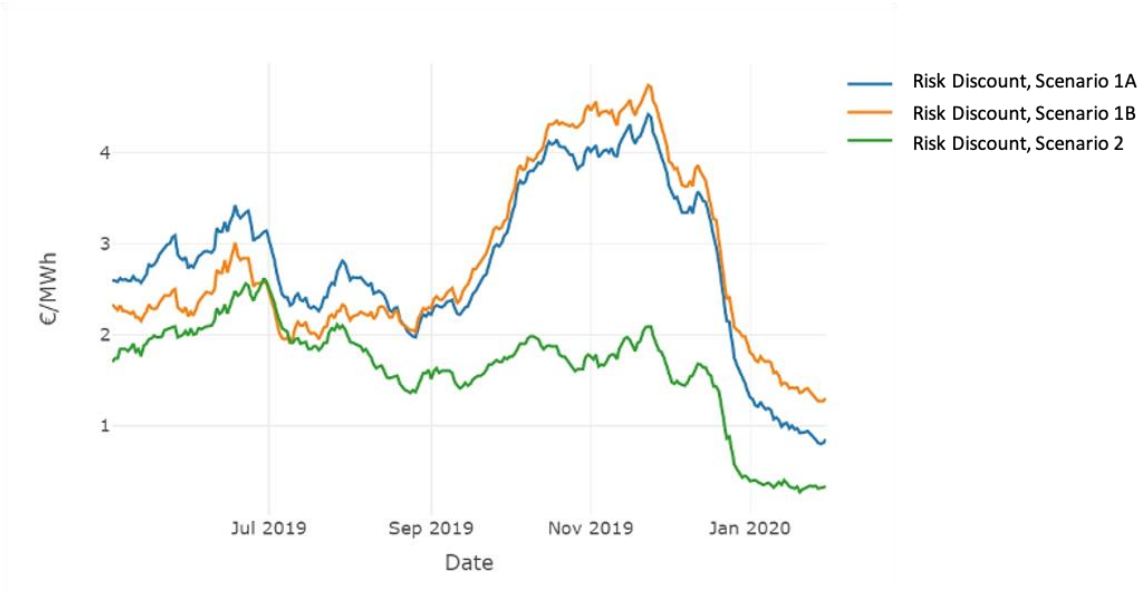

Figure A1(a) 91-day Risk Discount for IFA

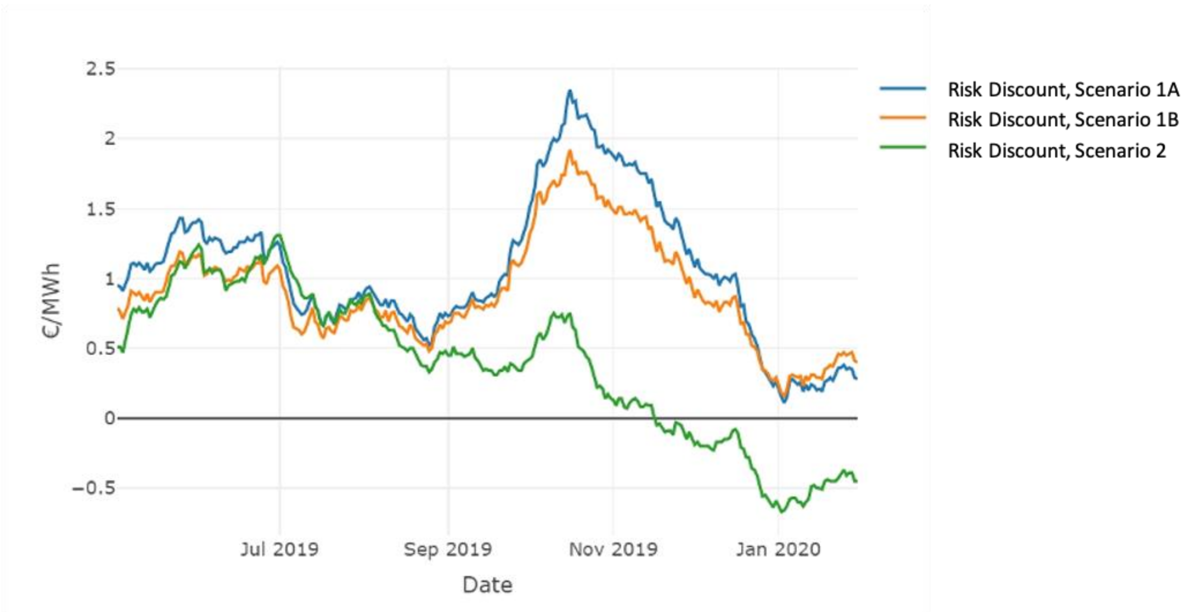

Figure A1 (b) 91-day Risk Discount for BritNed

Figure A1(c) 91-day Risk Discount for Nemo

Appendix B Worked examples of contracting

Contract decision making

Consider a generator 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. A French generator selling to an FR buyer requires 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 $\sum_h (s_m - p_{mh})$ 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, $p_m = 1/H \sum_h p_{mh}$, 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, $s_m > \mathrm{E}p_m$, 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.

Cross-border trading under the SDAC

Selling from FR 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.[28] 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 FR 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. The price of baseload PTR contracts secured in month-ahead PTR auctions are:

[28] 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.

$v_{FtG} = 1/H\ \Sigma_h$ 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 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 discount (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.

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 FR 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 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 FR consumer hedged with CfD: $s_{FR} – 1/H \sum_h p_{FRh}$,
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.

Hedging across borders with uncoupled interconnectors

We distinguish between hourly prices on different DAMs 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_C, p_C) in Country *C*;

V_{CtGh} — The GB D-1 auction price in hour *h* for the option on capacity on the interconnector from the Continent to GB, exercised if in expectation $P_{GBh} > p_{Ch}$, in the set of hours h^*;

Below France is taken as an example on how the JAO explicit auction works. 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[29] 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

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

FR SDAC. Income is $\Sigma_{h*}(P_{GBh} - V_{FtGh}) + \Sigma_{h**}\, p_{FRh}$.[30] 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 discount designed to rule out unprofitable nominations. Income is $\Sigma_{h*}(p_{FRh} + r - \varepsilon_h)$ in these hours while in the remaining hours it is $\Sigma_{h**}\, p_{FRh}$. Total income is $\Sigma_{h*}(r + \varepsilon_h) + \Sigma_h\, p_{FRh}$. 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 $\Sigma_{h*}(r + \varepsilon_h) + \Sigma_h\, s_{FR}$, 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 $\Sigma_{h*}(r + \varepsilon_h)$, where r is chosen to make this sum 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 $\Sigma_{h**}(P_{GBh} - s_{GB})$ to add to $\Sigma_{h*}(r + \varepsilon_h) + \Sigma_h\, s_{FR}$, or additional risk $\Sigma_{h**}\, P_{GBh} + \Sigma_{h*}(r + \varepsilon_h)$ 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 $\Sigma_{h*}(V_{FtGh} – v_{FtG})$, which does not add additional risk, but might reduce overall uncertainty viewed at M-1.

[30] 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 discount that discourages bidding that leads to such losses, at the cost of a lower utilisation.