The value of international electricity trading

A project commissioned by Ofgem

G. Castagneto Gissey, B. Guo, D. Newbery, G. Lipman,
L. Montoya, P. Dodds, M. Grubb, P. Ekins

How trading occurs over electricity markets at various timescales

The value of interconnectors in electricity trading

The impact on trading of unilaterally taxing carbon emissions

Measuring the efficiency of cross-border exchanges

The economic value of market coupling

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Preface

The Office of Gas and Electricity Markets (Ofgem) commissioned University College London (UCL) in May 2019 to conduct research regarding cross-border electricity trading between Great Britain and connected European Union markets, as part of the project 'Assessment of electricity trading in Great Britain' (ASTA). The project, led by UCL and involving the University of Cambridge, is intended to inform Ofgem's *State of the Energy Market* report. The views expressed in this report are those of the lead author alone.

Electricity interconnectors connect electricity systems and create value to society by enabling cross-border electricity trading. They create value to domestic consumers by enabling electricity imports from markets with lower prices as an alternative to higher-priced indigenous generation. In the future, interconnectors could become increasingly valuable as generation becomes more variable due to greater use of renewables. In response, countries are investing extensively in interconnectors. The value of international electricity trading depends on fuel prices and carbon policy in the connected markets, as these determine what electricity is traded (hence how total CO_2 emissions change), and how efficiently it is traded across borders (which affects the cost of electricity).

The report begins by explaining how electricity is traded over various timescales. It investigates the commercial and social value of trading over GB interconnectors. It assesses the impact of unilateral carbon pricing on trading and the magnitude of the resulting distortion. The report considers Great Britain and its links to Europe during the period 2013–2018 and derives several implications for national and international electricity policy.

Chapter 1 introduces the studies and presents their aims.

Chapter 2 explains how international electricity trading takes place in the EU and the benefits of trading. It focuses on trade between GB and the Continent over various timescales, with and without market coupling.

Chapter 3 quantifies the efficiency of electricity trading between GB and the electricity markets connected to GB between 2014 and 2018. It examines the efficiency and value of coupled and uncoupled trading over timescales ranging from year-ahead to intra-day. It considers the negative externalities of electricity trading;[1] asks whether coupling GB interconnectors to the Continent and the island of Ireland has eliminated inefficient trading;

[1] Social welfare considers costs and benefits to society, so includes all external costs of CO_2 emissions and other pollutants. Private welfare refers to increased welfare for interconnector owners alone, so is associated to commercial value.

and estimates the commercial value created by GB interconnectors. It investigates whether trading ahead on power exchanges and over interconnectors has converged after market coupling and discusses to what extent uncoupling would reduce trade efficiency.

Chapter 4 investigates the impact of a unilateral carbon tax on interconnector flows, revenue, and social welfare between 2015 and 2018 and its possible impact on future interconnector investment decisions. In 2013, GB implemented a unilateral carbon tax—the Carbon Price Support (CPS)—not replicated by our European neighbours. The policy has been instrumental in reducing carbon emissions in the electricity sector, leading to an unprecedented reduction in coal generation. However, a higher carbon price lead to higher GB wholesale prices and greater cross-border price differentials, affecting cross-border trade. This study considers how the CPS has affected GB electricity prices and imports; how it affected GB carbon tax revenue and interconnector congestion revenue; and estimates the resulting deadweight social welfare loss from trade distortions. It estimates its price impact on GB, France and the Netherlands. The chapter also considers the relation between prices on the forward, intra-day, balancing and ancillary markets and prices on the day-ahead market.

Chapter 5 considers how to best measure the efficiency of electricity trade and the results between GB and its European neighbours between 2013 and 2018. It classifies currently used metrics; devises new metrics that improve over existing ones; and qualitatively and quantitatively assesses these metrics, demonstrating their performance under several trading and market conditions. It then derives the economic value (social and commercial) of market coupling/uncoupling; quantifies how coupling has affected electricity net exports to and price differentials between GB and interconnected markets; and determines how price differentials between GB and these markets were affected in the short- and long-run after day-ahead coupling went live.

Chapter 6 summarises the report's main findings and draws policy implications. The results in this report have implications for cross-border electricity trading and interconnector use; the way in which electricity trading efficiency is measured; and the impact of carbon pricing policy on electricity trading between countries.

Executive Summary

The value of interconnectors (2013–2018)

1. **Market coupling has created efficient trading** at the day-ahead stage.

2. **The private (or commercial) benefits of existing interconnectors are large relative to their costs.** These benefits have been **amplified by increasingly liquid markets** over timescales from more than a year ahead to intra-day.

3. The **arbitrage revenue** for trading capacity on the day-ahead markets with France and the Netherlands (combined) averages about **€100 million/GW/yr**, or **€300 million/yr**.

'The commercial value of GB's largest interconnectors – those with France and the Netherlands – is substantial, with a combined value of about €500million/yr'

4. The **total commercial value of GB's largest interconnectors** – those with France and the Netherlands (IFA and BritNed) – is substantial, with a combined value estimated at €505 million/yr, including the value of the capacity contribution to security of supply.

5. **These interconnectors' social value is increased by about €25 million/yr** from the avoided infra-marginal generation cost but is reduced by about €30 million/yr by the distortion caused by carbon taxes in GB that are not charged by our neighbours.

6. The Single Electricity Market of the island of **Ireland** was coupled on 1st October 2018 and since then **the interconnector has been efficiently used in the day-ahead market**.

7. Before coupling, electricity trading between **GB and Ireland** was inefficient, with **flows in the wrong direction almost half the time**.

8. The Physical Transmission Rights (PTRs) auctions in 2015 traded at a substantial premium of 35% to the cost of securing an equivalent baseload supply in the day-ahead market, but this premium almost disappeared in the following years, consistent with **growing familiarity with, and liquidity of, the PTR auctions**.

9. **Hedging using Contracts for Difference (CfDs) on local power exchanges appear to offer as good a hedge as PTRs.** However, local CfDs appear more sensitive to news, such

as scheduled power outages that are alleviated in the day-ahead market auctions as wider areas are coupled.

10. If the GB market uncoupled, **establishing at least day-ahead and intra-day platforms for electricity**

14. Because the GB carbon tax is not replicated abroad it **transfers some €65 million/yr to France and the Netherlands** as well as adding distortionary costs when trade flows change.

The unilateral British carbon tax, the Carbon Price Support, dramatically reduced the electricity system's carbon emissions but distorted trade

11. **trading over the interconnectors** could reduce trading inefficiency, but would be unlikely to capture all of the benefits of a pan-European simultaneous auction.

12. CfDs on neighbouring PXs supplemented by PTRs might recover most of the potential losses from market uncoupling.

Impact of GB's Carbon Price Support (CPS) on wholesale electricity trading (2015–2018)

13. The purpose of the CPS implemented from 2013 is to reduce carbon emissions from electricity generation and give more predictable investment signals. The CPS has been a **successful in dramatically reducing coal generation**. Following an increase of the CPS to £18/tonne CO_2 in 2015 the share of **GB coal-fired generation fell from 41% to 7% in 2018.**

15. As a consequence of using cleaner but more expensive energy, over 2015–2018, the **CPS has raised the GB day-ahead price by an average of about €10/MWh** in the absence of compensating adjustments through increased imports.

16. The actual **price differential with our neighbours (France and the Netherlands) increased by about €8/MWh** allowing for domestic generation to be replaced by cheaper imports.

17. Nearly 20% of the increase in the GB day-ahead electricity price from **the CPS was passed through to higher French electricity prices** and 30% to **higher Dutch prices.**

18. The CPS increased **GB imports** from IFA and BritNed (combined) by 13 TWh/yr, thereby reducing **carbon tax revenue** by €103 million/yr.

19. The **deadweight loss due to carbon cost distortion** was €20.3 million/yr for IFA and €9.4 million/yr for BritNed, or

€30 million/yr in total, or slightly more than the inframarginal surplus.

20. The CPS **increased IFA congestion income by €81 million/yr and BritNed congestion income by €52 million/yr, in total €133 million/yr**. Half of this accrues to France and the Netherlands.

21. The increased congestion income from the CPS, which mostly comes from GB electricity consumers, might **over-incentivise investment in additional interconnectors, to import from fossil-based systems lacking a comparable carbon tax**.

22. The social benefit from **reduced carbon emission** may be **partly offset by increased imports of more carbon-intensive electricity**. However, the ETS Market Stability Reserve should reduce aggregate EU emissions by a large fraction of the GB reduction.

23. The **case for an EU-wide carbon price support that would reduce emissions is further strengthened** by the desirability of correcting trade distortions.

24. We cannot reject the hypothesis that 100% of the CPS was passed through in higher prices, **consistent with (but not proof of) a competitive GB wholesale market**.

International electricity trading efficiency and value of market coupling (2013 –2018)

25. After the introduction of day-ahead market coupling, there was a **decrease in trading inefficiency** between GB and France from 5% in 2013 to <1% in 2018, and between GB and the Netherlands from 11% in 2013 to <4% in 2018.

26. During 2015–2018, an uncoupled GB market (without making use of other market contracts), might have led to an **increase in inefficient trading between GB and France from <1% to >10% and with the Netherlands from 4% to about 8%**.

Market uncoupling could lead to more inefficient trading

27. During the same period, an **uncoupled GB market** might have led to the electricity **price differential with France (Netherlands) rising by 3% (2%), net imports into GB decreasing by 26% (13%), congestion income decreasing by 10% (5%), and infra-marginal surplus decreasing by 1.6% (1.6%) of coupled congestion income.**

28. The **impact of market uncoupling** increases with the capacity of the interconnector and decreases with the average price differential.

29. If the **EU were to implement an equivalent carbon tax** to GB's Carbon Price Support, electricity prices between GB and both France and the Netherlands could converge (with the GB price being close to the French price, while the GB-NL price differential would likely remain substantial).

30. With prices closer together, the impact of **market uncoupling could change the volume of trade flows**. However, the cost of the trade inefficiencies caused by uncoupling would be reduced as the price differences and hence congestion revenues would also decrease. Inefficient trading decisions are less likely when price differences are larger.

This report was commissioned by the Office of Gas and Electricity Markets (Ofgem). It was a collaboration led by UCL involving the University of Cambridge for the purpose of informing Ofgem's State of the Energy Market report.

AUTHORS

Giorgio CASTAGNETO GISSEY
Bowei GUO
David NEWBERY
Guy LIPMAN
Luis Guillermo MONTOYA
Paul DODDS
Michael GRUBB
Paul EKINS

ABOUT UCL

University College London (UCL) is a public research university in London, England, and a constituent college of the federal University of London. The UCL Institute for Sustainable Resources and the UCL Energy Institute deliver world-leading learning, research and policy support on the challenges of climate change, energy security, and energy affordability. We are part of the Bartlett: UCL's global faculty of the built environment. Our institutes bring together different perspectives, understandings and procedures in energy research, transcending the boundaries between academic disciplines. They coordinate multidisciplinary teams from across the University, providing critical mass and capacity for ambitious projects.

The main contact for this work is Dr Giorgio Castagneto Gissey (UCL), who may be reached by email at: g.castagneto-gissey@ucl.ac.uk.

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DISCLAIMERS

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4MMC	4M Market Coupling
ACER	Agency for the Cooperation of Energy Regulators
ATC	Available Transfer Capacity
CfD	Contracts-for-Differences
CPS	Carbon Price Support
CWE	Central Western Europe
DA	Day-ahead
DAM	Day-ahead Market
DFTEU	Departure from the European Union
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
EWIC	East-West Interconnector
FAPD	Flow Against Price Difference
FAPD	Flow against price differential
FBMC	Flow Based Market Coupling
FTR	Financial Transmission Right
FWPD	Flow with price differential
IDM	Intra-day market
IEM	Integrated Energy Market
IFA	Interconnexion France-Angleterre
MRC	Multi Region Coupling
NTC	Net transfer capacity
PCR	Price Coupling of Regions
PTR	Physical Transmission Right
QREEM	Quarterly Report on European Electricity Markets
SEM	Single Electricity Market of the island of Ireland
UST	Universal Standard Time
VRE	Variable Renewable Electricity

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1 Introduction

Interconnectors create value to electricity systems by enabling electricity imports from markets with lower prices as an alternative to higher-priced indigenous electricity generation. In the future, interconnectors could become increasingly valuable as generation becomes more variable due to higher penetrations of renewables. In response, countries are investing extensively in interconnectors. Imports might be expected primarily during periods of high residual demand, while exporting surplus renewable electricity avoids curtailment. Investing in new European interconnection capacity could therefore become a key strategy to integrate renewables and nuclear power stations in the electricity systems of GB and Ireland.

Interconnection can reduce electricity price peaks and troughs caused by demand and weather-dependent supply, as these tend to occur at different times of the day across Europe. GB currently has 5 GW of electricity interconnection capacity, of which 2 GW links to France and 1 GW to the Netherlands, 1 GW with the Irish Single Electricity Market (I-SEM) and, since very recently, 1 GW to Belgium. Ofgem have approved up to 15.9 GW (so a 10.9 GW increase on current levels), of which 10.4 GW to the Continent and 0.5 GW to Ireland. Of this 15.9 GW, 4.8 GW is currently under construction – IFA2, NSL and Viking Link all with C&F (3.8 GW) and ElecLink with an exemption (1GW) – and up to 20 GW of

additional interconnection capacity has been proposed, with most of this shown to be potentially valuable to GB electricity consumers and society as a whole.[2]

Social welfare gains between markets depend on the price differential between the two connected markets as well as the efficiency of electricity trading (Ochoa and van Ackere, 2015). Debates about the Third Energy Package pointed to the inefficiency of trading via interconnectors to argue for reform, specifically to change from Available Transfer Capacity (ATC) calculations to a flow-based market coupling model. Since 2014, market coupling regulations have therefore been introduced. Market coupling is an agreement between transmission system operators and market operators to use a common algorithm for settling electricity market transactions through interconnectors. Market coupling regulations were implemented by EU markets, including Great Britain, to improve the efficiency of cross-border electricity trading within the EU and to allow Continental electricity systems to be synchronised so that flows across borders follow the laws of physics rather than the dictates of national regulators.

'Interconnectors create value to electricity systems by enabling electricity imports from markets with lower prices as an alternative to higher-priced indigenous electricity generation'

Trading electricity over interconnectors has evolved to cover various timeframes, which are distinct marketplaces for electricity. These include the day-ahead market, various forward markets such as year- and month-ahead, and various intra-day markets, which all occur up to close before real-time, as well as imbalance and ancillary markets.

This report considers various aspects of interconnector trading. We assess the value of GB interconnectors to the European Union over markets at different timescales, examine the impact of asymmetric carbon pricing between GB and EU countries and consider how it affects international electricity trading, and define new and improved ways to measure how inefficiently (or efficiently) countries trade electricity across borders.

We begin by breaking down the process of trading electricity, describing key associated concepts such as market coupling.

We then assess the value of British interconnectors to their owners and that to society. We do so in order to understand how valuable interconnector investments are and whether there is a mismatch between private and social value that requires attention to generate more efficient investments that reduce costs to consumers. Another major aim of this

[2] Ofgem (2014) Near-term IC cost-benefit analysis; Redpoint (2013) Impacts of further electricity interconnection on Great Britain; National Grid (2014) Benefits of interconnectors to GB transmission system.

analysis is to establish whether the introduction of market coupling has led to more efficient trading between GB and its neighbouring countries. This is important because more efficient trading of electricity with adjacent countries leads to cheaper electricity for British consumers.

As with other measures to decarbonise GB electricity, such as renewables support, GB's Carbon Price Floor (CPF), a policy framework implemented in 2013 that tops up the EU carbon price by a level known as the Carbon Price Support (CPS), has increased wholesale costs. The CPS has been a highly successful policy that led to an unprecedented reduction in carbon-intensive electricity generation, as has the substantial increase in the share of renewable generation. As carbon-intensive units are typically at the margin, the CPS will tend to increase the wholesale electricity price. Interconnector owners trade and profit based on the differences between electricity prices in the two connected markets, so we consider how the CPS has affected trading through GB-linked interconnectors and the countries' electricity prices, as well as revenues for interconnectors owners. While the CPS has been important by driving coal almost completely out of the GB electricity system, it may also have unintended consequences on international trade, which we identify and quantify.

Market coupling improves allocative efficiency since the two commodities involved (electricity and interconnector capacity) are required to be bought and sold in combination and simultaneously

Interconnector trading occurs over several marketplaces or timescales. These include the day-ahead market, various forward markets such as year- and month-ahead, and various intra-day markets, which all occur up to close before real-time. These are followed by the imbalance market, which occurs after gate closure. All such markets allow participants to adjust their physical positions as we move closer (or farther away) to real time, based on more up to date information for trades to occur. Ancillary markets are also used so that generators can provide various grid services and also hedge their positions in each other market.

Trades in the forward, intra-day, balancing and ancillary markets affect prices and flows in these markets. As wholesale day-ahead prices play a leading role in determining electricity bills, we also consider the extent to trades in the day-ahead market affect the wholesale electricity price.

To determine how effectively interconnectors allocate electricity across borders, it is necessary to accurately measure the inefficiency of these allocations. Our work extends to consider how this inefficiency is best measured. We found that current metrics for the inefficiency of interconnector use are not robust to various market conditions. This includes extreme prices, and flows going in the wrong economic direction (which transfer power

from high to low electricity prices). The latter tends to occur especially in uncoupled day-ahead markets, whilst the former is a typical occurrence in day-ahead markets as a consequence of electricity not being economically storable. Given the identified deficiencies, we reviewed the current metrics and assessed them against historical and simulated extreme data. We then develop two new metrics that are designed to capture the underlying efficiency of electricity trading and demonstrate their performance against existing metrics. In addition, we quantify the economic value of market coupling, and show how coupling has affected electricity trading and price differentials between GB and interconnected markets.

1.1 Objectives and scope

We study cross-border electricity trading inefficiency using GB and interconnected electricity markets as a case study; consider the economic value of market coupling, as well as the value of interconnectors to their owners and to society; assess the impact of a unilaterally-imposed carbon tax on electricity trading, with emphasis on GB's Carbon Price Support and its implications for trades between GB and France; and consider the relationship between trades in electricity markets at various timeframes.

The first study examines the private and social value of interconnectors linked to GB. It examines the impact of trading over different timescales ranging from over a year ahead to intra-day, the social benefits that are not reflected in the private benefits, and the extent to which other financial markets might alleviate the potential social losses from market uncoupling, which is expected post EU exit. We address the following research questions and aims; this study will:

- quantify the success of market coupling (or the efficiency of interconnector use) over GB-linked electricity markets;
- examine the efficiency and value of uncoupled and coupled trading for four DC interconnectors to GB, over different timescales, from over a year ahead to intra-day;
- consider the social benefits that are not reflected in the private benefits;
- ask whether coupling GB interconnectors to the Continent has eliminated inefficient trading, and estimate the commercial value created by interconnectors to GB;
- considers whether coupling has reduced trade inefficiencies with the island of Ireland, which coupled on 1 October 2018;
- investigate whether trading ahead on power exchanges and over interconnectors has converged;
- discuss whether uncoupling would reduce efficiency other trading hubs provide;
- also focus on discussing the day-ahead market and the role of the longer-coupled interconnectors (i.e. IFA and BritNed); and
- investigate the possible impact of the GB carbon tax on future interconnector investment decisions.

In our second study, we investigate how the imposition of a unilateral carbon tax not shared by interconnected markets affects electricity flows, congestion revenue, and future investment decisions. In particular, this work:

- provides an assessment of the impact of the GB Carbon Price Support (CPS) on cross-border electricity trading prices and volumes between GB and the Continent;
- quantifies the impact of the CPS on congestion income;
- derives the impact of the CPS on social welfare; and
- assesses the degree to which the CPS has been passed through to cross-border markets trading with GB.

In our third and final study, we review the literature on measures of the electricity trading inefficiency, finding various drawbacks in existing metrics. We devise new metrics of interconnector utilisation inefficiency to address the identified drawbacks and demonstrate the added value of incorporating as much of the available interconnector utilisation information which current metrics do not. We show the new metrics to outperform existing metrics using historical data and to be more robust when stress-tested against extreme prices and flows going in the wrong economic direction. The study also provides an assessment of the economic value (social and commercial) of market coupling. More specifically, it:

- classifies the current measures of market integration, focussing on measures of interconnector utilisation inefficiency;
- reviews the literature covering these measures;
- devises new measures that improve on existing ones;
- quantitatively assesses the new measures against existing ones using real and extreme simulated data;
- derives the level of trading inefficiency between GB and interconnected countries;
- derives the economic value of market coupling;
- considers how trades in the day-ahead market are related to trades in other electricity markets (forward, intra-day, balancing and ancillary markets);
- quantifies how market coupling has changed electricity net exports to and price differentials between GB and interconnected markets; and
- shows how price differentials between GB and these markets may change after market coupling, how fast price differentials adjusted, and to which extent.

1.2 Report structure

Chapter 2 discusses concepts and processes behind international electricity trading via interconnectors in modern economies. Chapter 3 is an analysis of the commercial and social value of interconnectors in markets at various timescales. Chapter 4 considers the impact of carbon pricing asymmetries between two interconnected markets and how this affects trade. Chapter 5 reviews the existing metrics to measure the efficiency of electricity trading and identifies their limitations, proposing new metrics that improve over these. It also derives the economic value of market coupling and its impact on trade. Finally, Chapter 6 summarises the report and provides our concluding remarks.

2 Trading electricity via interconnectors

This chapter provides useful background information to the topics examined in this report. We consider how trading occurs via interconnectors; explain the concept of market coupling and its benefits; and provide an overview of Great Britain's interconnectors. We consider how interconnector scheduling occurs, both in coupled and uncoupled markets, illustrating trading timelines under each of these market arrangements. We also describe the relationships between electricity markets at various timescales, providing evidence from the literature. Finally, we discuss how decoupling two interconnector electricity markets would affect the trading parties involved.

2.1 Market coupling and interconnectors

The owner of the interconnector, or the two transmission companies at either side of the border (for AC land interconnectors) are paid the loss-adjusted price differential between the two markets multiplied by the transmitted volume. Most interconnectors sell their capacity via auctions that cover future periods, with the remaining capacity auctioned in the day-ahead market. During the day-ahead timeframe, any capacity that is not nominated from forward sales is made available for trading. For most internal EU or EEA interconnectors, this allocation occurs through market coupling, that is, an implicit allocation. Coupling began in the day-ahead market, continued in the intra-day market, and is only used to a limited extent in the imbalance market (ACER, 2017).

The day-ahead market coupling algorithm, EUPHEMIA, was introduced in 2014 and uses bids and offers of generation and demand in each market (and the interconnector capacity) to schedule optimal flows.

Starting in June 2018, most EU interconnectors are part of a coupled intra-day market. This is similar to coupling in the day-ahead market in that interconnector capacity is allocated implicitly and not sold separately, but different because bids and offers are considered continuously rather than at a defined point of the auction. At present, GB interconnectors still use explicit auctions of capacity at pre-defined times within the intra-day stage. Supposing that all capacity has been utilised at the day-ahead stage, which is typically the case for GB interconnectors, then the only capacity available for trading in the intra-day market is to reverse the direction of flow. More capacity may be available intra-day if either the prices have equalised in neighbouring zones day-ahead so not all capacity is needed then, or if the available physical capacity varies.

2.2 Benefits of market coupling

Several studies have estimated the benefits of more efficient electricity market integration, with most using simulation approaches. Neuhoff *et al.* (2013) considered the benefits of the most efficient form of market integration via nodal pricing in Europe. They included a large volume (125 GW) of predicted future wind connection and found savings of 1.1–3.6% of variable operating costs. With fuel costs roughly half the overall wholesale market value, the gains from full integration were estimated as 0.6–1.8% of wholesale market value. Leuthold

et al. (2005) studied the benefits of moving to nodal pricing, with an additional 8 GW in offshore wind to Germany. They estimated that gains of 0.6–1.3% came by simply switching to nodal pricing, with a further 1% from pricing the additional wind on a locational basis.

Newbery *et al.* (2013) provides detailed reviews on the quantitative benefits of market integration. In another research paper, Newbery *et al.* (2016) estimated the potential benefit to the EU of coupling interconnectors to increase the efficiency of trading day-ahead, intra-day and sharing balancing services efficiently across borders. They found that further gains are possible by eliminating unscheduled flows and avoiding the curtailment of renewables, with short-run gains potentially as high as €3.3 bn/yr more than the current gains from trade. The authors also find that one-third of these benefits comes from day-ahead coupling and another third from shared balancing. More recent evidence was surveyed by Pollitt (2018), but the author concludes that measurable benefits are likely to be small, in part because there has been a large rise in subsidised renewable generation driven by decarbonisation efforts.

2.3 Overview of Great Britain's interconnectors

Great Britain's electricity grid is connected to other European markets by interconnectors, allowing markets to meet electricity demand more cheaply. The use of these interconnectors has been considered in the existing literature from an economic perspective, however there has been limited discussion of how individual market participants operate in these markets.

The remainder of this chapter provides a description of how traders operate in interconnected electricity markets. We begin by providing a brief overview of Great Britain's current interconnectors. This is followed by an overview of physical power trading in Europe, forming the context in which interconnectors exist. We then describe how interconnector capacity is auctioned, focusing on GB's largest interconnectors (to France and the Netherlands), and a description of how interconnector capacity is scheduled, both manually and through the 'market coupling' mechanism. Finally, we conclude by commenting on the possible outcomes of a potential decoupling of the interconnected markets, which is likely to occur as a result of the UK leaving the European Union.

Interconnector name	Connecting country	Capacity	Project delivery date
IFA	France	2,000 MW	1986
Moyle	Ireland	500 MW	2002
BritNed	Netherlands	1,000 MW	2011
EWIC	Ireland	500 MW	2012
NEMO	Belgium	1,000 MW	2019

Table 2.1. Interconnectors to GB, including interconnector name, connecting country, interconnector capacity, and project delivery date. Source: Ofgem (2019).[3]

[3] https://www.ofgem.gov.uk/electricity/transmission-networks/electricity-interconnectors

Great Britain (the island comprised of England, Scotland and Wales) is currently connected to other European markets by five interconnectors, as shown in Table 2.1.

This report mostly focuses on IFA and BritNed, which are GB's most important interconnectors because of their larger capacity and earlier involvement in the market coupling. These interconnectors differ from many other interconnectors in Europe in that transmission losses are applied to participants flowing electricity between markets. That is not to say that transmission between, say, France and Germany, does not incur physical transmission losses; however, the market structure means that an owner of capacity from France to Germany can schedule 1 MWh to leave France and receive 1 MWh in Germany. In contrast, the owner of capacity from Great Britain to France will receive less electricity in France than they deliver in Great Britain. For example, IFA currently has a 1.17% loss factor. As a result, capacity owners need a price differential exceeding the loss factor to justify flowing between markets.

Before discussing interconnector capacity and scheduling, it is helpful to provide a brief overview of certain aspects of physical electricity trading in many European electricity markets.

2.4 Electricity markets

Interconnector trading covers various timeframes. Each of these constitutes a distinct marketplace for buying and selling electricity and include the forward, day-ahead, and intra-day markets, in which trading ceases at separate times prior to the generation of electricity.

Forward markets operate from years ahead, up until the day-ahead auction. These trade between counterparties or on power exchanges. Liquidity is concentrated on certain products, typically the next year or two, the next quarter or two, or the next month or two, in each case for baseload (all hours) and peak load. Forward electricity trades can be physical, resulting in a physical position which must be closed out or taken to the balancing market. They can also be financial, being settled against the day-ahead prices. Interconnector capacity can be bought in forward auctions, and either physically nominated, or more commonly released for financial settlement in the day-ahead auction process.

Day-ahead auctions consolidate bids and offers in each region for each hour the following day. They are coupled, meaning that they also take into account the available interconnector capacity between each market, optimising flow from low to high price regions, and minimising price differences. This process is conducted by means of an algorithm named 'EUPHEMIA' (Pan-European Hybrid Electricity Market Integration Algorithm). The outcome of day-ahead auctions is to determine a set of hourly prices for each region, as well

as a day-ahead flow schedule. These auctions are operated by a number of exchanges at midday Central European Time (CET)[4].

Intra-day markets commence after the day-ahead auctions are concluded, and typically run until around an hour before delivery. Great Britain and Ireland allow the trading of half-hours or larger blocks. France, Belgium and Netherlands allow the trading of individual hours or larger blocks. All trades are physical, resulting in a physical position which must be taken to the balancing market or used to eliminate the risk of an existing physical position. While intra-day trading can occur bilaterally, exchanges offer liquidity and transparency. Exchanges offer auctions in which bids and offers are collected and cleared at specific times, as well as continuous trading in which bids and offers are accepted at any time. The operators of the five interconnectors connecting GB also auction and take nominations for capacity during the intra-day period as nomination deadlines differ by interconnector. Some intra-day markets have recently introduced coupling, allowing intra-day interconnector capacity to be optimised alongside intra-day bids and offers in connected regions.

Balancing markets allow each region's electricity system operator to ensure that supply balances demand in real time. If system demand exceeds supply, the system operator will pay flexible participants to increase generation, prioritizing those asking the lowest price. If system supply exceeds demand, the system operator will pay participants to reduce generation, prioritising those bidding the highest price. In some cases, system operators may take advantage of flexible resources, such as demand side response or available interconnector capacity, to reduce balancing costs. This balancing process determines an imbalance price, which is applied to any market participants who have a non-zero net physical position in the balancing market, taking into account physical trades and physical supply/demand. Imbalance prices are highly volatile, giving participants an incentive to close out positions to minimise exposure to them.

2.5 Overview of physical electricity trading

In Great Britain, and in each of the markets connected to it, generators deliver electricity to the grid each hour, and electricity suppliers are responsible for electricity consumed from the grid by their domestic and commercial customers. In addition, market participants, which may include banks and hedge funds as well as generators and retailers, may contract to 'buy' or 'sell' electricity to other participants. Finally, the grid may need to buy or sell electricity to ensure that the grid ultimately balances. Any participants that are net long (i.e. the quantity generated or bought less any consumed or sold is positive) will receive the balancing price, while any participants that are net short (i.e. the quantity generated or bought less any consumed or sold is negative) will pay the balancing price. These balancing prices are highly volatile; in the UK in 2018 they ranged from £-150 to £990/MWh. To avoid

[4] The start and end of the European electricity day, and times for capacity and day-ahead auctions adjust for daylight savings. Throughout this document a reference to CET implies CET in winter, and Central European Summer Time (CEST) in summer, that is, 1 hour ahead of prevailing UK time.

risking exposure to balancing prices, participants have an incentive to ensure they are neither long nor short in physical power. This is particularly challenging for electricity suppliers who must predict customer demand, and often do not find out their customers' actual demand until months later.

Participants can balance their positions and thereby reduce exposure to balancing prices in three main ways: buying or selling in auctions, buying or selling in short-term markets, or buying or selling in long-term bilateral or exchange markets.

Each market holds a day-ahead auction at midday CET, in which participants can submit bids to buy electricity or offers to sell electricity. A clearing price is calculated and used for clearing all bids above that price and offers below that price. EPEXSPOT and N2EX are two exchanges that allow participants to buy or sell in the day-ahead auctions.

EPEXSPOT also holds smaller auctions for Great Britain at various points leading up to the hour in question. These auctions provide transparency, but do not have great liquidity. As an illustration of the limited liquidity, we show the trading volumes on EPEXSPOT for delivery day 26 Feb 2019 in Table 2.2.

Time (CET)	Volume traded*
12:00	109.2 GWh**
16:30	11.7 GWh
18:30	1.3 GWh
09:00**	0.3 GWh

Table 2.2. Time and volume traded on a sample day. Source: EPEXSPOT[5]. Key: * for delivery day 26 Feb 2019; ** or 13% of total demand; ***Only covers half-hours in the second half of the day).

Many other European markets do not offer intra-day auctions. They do, however, provide continuous intra-day trading on EPEXSPOT (as does Great Britain). These run alongside bilateral trading of individual half hours, up until a point described as Gate Closure (typically an hour before the period start time). Bilateral trading offers little transparency, and it is difficult to judge liquidity. For example, participants will often trade a block of a few hours, making it impossible to identify the relevant price for each hour within the block.

By far the majority of electricity trading happens instead as part of long-term contracts spanning more than a month, typically covering either baseload (all hours) or peak-load (weekdays, 8am-8pm CET). Individual weeks and days can also be traded from about a month ahead until the morning ahead. There is only very occasional trading of individual hours or custom profiles more than a day or two ahead.

At this level, there is a distinction between physical and financial contracts. The majority of contracts are physical, traded between generators, retailers and wholesale participants, which ultimately lead to a physical position that must be closed out or settled in the

[5] This data can be seen in real time on https://www.apxgroup.com/market-results/apx-power-uk/dashboard/. The total demand forecast is taken from Elexon's Transmission System Demand Forecast (https://www.bmreports.com/bmrs/?q=demand/dayanddayaheaddemand).

imbalance markets. It is also possible to enter into financial contracts that settle based on a published index, usually the day-ahead hourly auction prices. Futures exchanges, for example EEX, allow active trading of long-term UK, French, Belgian and Dutch electricity, which are financial, however offer the ability to automatically convert to physical positions in the day-ahead market.

Individual weeks and days can also be traded bilaterally and on exchange from about a month ahead until the morning ahead. There is only very occasional trading of individual hours or custom profiles more than a day or two ahead.

2.6 Cross-border Electricity Trading

IFA and BritNed are both able to earn revenue directly by allowing power to flow from a lower priced to a higher priced market. However, this strategy leaves them with significant market uncertainty. As a consequence, both IFA and BritNed auction interconnector capacity to electricity market participants in advance. Such participants are in a better position to manage that uncertainty and may even find it to be an approximate hedge for their existing exposure. For example, BritNed auctions around 90% of capacity before the day-ahead.[6]

IFA hold long-term auctions:

- for each year, on four occasions, in April, May, Jun, and July of the preceding year;
- for each summer (April-Sept), on two occasions, in Oct and Nov of the preceding year;
- for each winter (Oct-Mar), on two occasions, in April and May;
- for each quarter, twice, slightly more than one and two months before; and
- for each month, three times, 2, 3 and 5 weeks before.

BritNed hold long-term auctions:

- for each year, on six occasions, in April, May, Jun, Sept, Oct and November of the preceding year;
- for each quarter, once, approximately 6 weeks before;
- for each month, 2, 4 and 6 weeks before; and
- for each weekend, once, on the Wednesday before.

In addition, IFA and BritNed auction additional intra-day capacity, which can be scheduled up to a few hours ahead of flow. Participants of these auctions can bid for individual hours as shown in Table 2.3:

[6] https://www.britned.com/participants-portal/key-links-and-documents/auction-schedules/

Hours (CET)	Auction time
IFA [7]	
00:00-14:00	19:30
14:00-00:00	08:50
BritNed [8]	
00:00-16:00	18:30-19:00
16:00-00:00	10:30-11:00

Table 2.3. Auction times for IFA and BritNed.

IFA previously also offered day-ahead capacity, which was auctioned and scheduled the morning before the day of flow, however this process was stopped when coupling was introduced in 2014 (as discussed in the next section).

2.7 Interconnector scheduling

Historically, there have been two ways in which interconnector flows have been scheduled. The first is manual, or uncoupled, in which capacity holders choose which time periods to schedule. The second is automatic, or coupled, in which volumes are automatically scheduled and payoffs realised based on submitted bids/offers in each market. Great Britain's interconnectors have always allowed manual scheduling, and since 2014 have allowed coupled scheduling as part of the day-ahead market. The following sections describe these processes in more detail.

2.7.1 Manual scheduling

The capacity owner can nominate to flow electricity from one market to another. There are specific deadlines by which capacity must be nominated. For example, long-term capacity must be scheduled two days ahead, and intra-day capacity can be scheduled several hours ahead. Participants who schedule to flow from market A to market B will receive a long position in market B and a short position in market A, which can be used to offset existing or subsequent physical positions in those markets.

Given the limited transparency and liquidity of short-term physical markets, it is difficult to determine when to schedule capacity, or to assess the rationality of capacity owners' decisions to schedule. Let us consider two scenarios:

- A capacity owner with a long position in market A and a short position in market B, can either: a) schedule to flow on the interconnector; or b) sell power in market A and buy power in market B, either bilaterally, in the day-ahead or intra-day auction, or in the balancing market. The latter may prove more costly, even if the capacity is against the expected price difference, given the illiquidity of the markets.

[7] https://www.ofgem.gov.uk/system/files/docs/2016/10/ifa_access_rules.pdf p57
[8] https://www.britned.com/documents/13/BritNed_Trading_and_Nomination_Guide.pdf, p15

- A capacity owner with no existing positions can either: a) allow the capacity to lapse; or b) schedule the capacity to flow from A to B, selling power in market B and buying power in market A (either bilaterally, in the day-ahead or intra-day auction, or in the balancing markets). The latter may again prove more costly, even if the capacity is against the expected price difference, given the illiquidity of the markets.

It is important to recognise that interconnector flow is scheduled after the day-ahead auctions, and before the balancing process. This means that even if we see differences in day-ahead prices between two markets, or between balancing prices in two markets, we cannot conclude that market participants were necessarily irrational not to schedule capacity. Intra-day trading commences before the intra-day capacity is scheduled, and continues after the deadline for scheduling, however, these have limited transparency, so it is difficult to assess from these if profitable opportunities to flow are being missed.

There are steps that could be taken to improve the efficiency of interconnector scheduling. Efforts to increase liquidity and transparency of short-term markets, for example through increased use of short-term electricity platforms, would allow capacity owners to more easily observe and profit from observed price differentials.

2.7.2 Scheduling via coupling

Coupling currently operates as part of the day-ahead auction process. Day-ahead auctions allow participants to provide bids and offers for each market. With coupling, the auction mechanism additionally considers available capacity to flow electricity between markets. This process is performed by an algorithm called EUPHEMIA (Pan-European Hybrid Electricity Market Integration Algorithm). The algorithm optimises purchases, sales and flows, and simultaneously calculates the clearing price for each market, along with which bids and offers are accepted, and what flow occurs between markets.

For example, if market B would otherwise settle at a higher price than market A, available capacity may be used to flow additional power from market A to market B, raising the clearing price in market A and reducing it in market B, thus decreasing the price differential. For interconnectors that include a transmission loss factor, scheduling flow will not eliminate the differential, but will at best reduce it to the price multiplied by the loss factor. If the differential is reduced to the price multiplied by the loss factor, the capacity is considered unconstrained, and the capacity owner will not receive any revenue. If, on the other hand, despite flowing the full capacity, the differential remains greater than the price multiplied by the loss factor, the interconnector is considered constrained. In this case, the owners of capacity in the flow direction receive revenue from the interconnector operator; this is calculated based on their share of the flow, multiplied by the price differential, reduced for losses. This revenue will come from the interconnector operator receiving net revenue from selling in market B and buying in market A.

Consider an example in which, without flow, the price in France would be €45/MWh and the price in Great Britain would be €30/MWh. There is 2,000 MW of interconnector capacity, and the mid-channel loss factor is 1.17%. Suppose that flowing the full 2,000 MW from Great

Britain to France increases the price in Great Britain to €35/MWh and reduces the price in France to €40/MWh (i.e. it is constrained). Then, capacity owners would get 40*(1-0.017)-35*(1+0.017) = €3.725/MWh.

It should be noted that long-term capacity owners may choose to schedule their long-term capacity manually, rather than enter it into the coupling process. For example, supposing a participant has long and short physical positions in two interconnected markets and has purchased interconnector capacity to hedge these. By manually scheduling the capacity, it can reduce or eliminate its risk. In contrast, if this capacity was settled through coupling, it may still need to close out its positions manually. In order to schedule long-term capacity manually, the owner must notify the interconnector operator ahead of the day-ahead process, allowing it time to include the capacity in the coupling process. For IFA, the deadline for nominating long-term capacity is 9:30 CET day-ahead. For BritNed, the deadline is 16:30 CET the business day before the day-ahead.

Even if the day-ahead auctions are coupled and the optimal flow is determined, it may still prove appropriate to schedule additional volumes. The additional volumes can be in the direction of the previously scheduled flow, or in the reverse direction. For example, if the capacity of the interconnector is 2,000 MW in both directions, and 1,000 MW has been scheduled from Great Britain to France, participants could decide to schedule up to 1,000 MW more from Great Britain to France or could schedule up to 3,000 MW from France to Great Britain. This scheduling can be done manually in intra-day markets, as described in the previous subsection.

2.7.3 Coupled vs uncoupled markets

The European Commission stipulated that under market coupling rules, electricity must be sold together with interconnection capacity (EU Commission, 2016). Market coupling uses *implicit* auctions, where each player does not receive allocations of cross-border capacity, rather simply bidding for energy on their power exchange. The exchange then uses the available cross-border transmission capacity to minimise the price difference between two or more areas (Epex Spot, 2019).

The opposite situation occurs when markets are uncoupled, in which a company trading power would need to reserve the interconnector capacity, then buy power in the first market and sell it in the second. In uncoupled markets, *explicit* auctions occur whereby the two commodities, transmission capacity and electrical energy, are traded separately. This implies a lack of information about the prices of the other commodity. This lack of information can result in an inefficient utilisation of interconnectors and results in less social welfare and price convergence and more frequent adverse flows, i.e. flows going in the wrong economic direction (Nord Pool Spot, 2019).

In uncoupled markets, market rules do not allow for supply and demand in the first market to affect the price prevailing in the second market. This may occur because of the markets having different closure times; because one market is disallowed from receiving information from the other market; or, by a requirement to submit definitive demand schedules and

supply prices for auction. The lack of information prevents full allocative efficiency for each market and the two markets as a whole. In market equilibrium, coupled markets should fully equilibrate prices subject to transmission capacity constraints, which results in short-run welfare being maximised (Geske *et al.*, 2018). The central purpose of market coupling is in fact to maximise the economic welfare of all market players.

If a market publishes its results before bids are submitted in the other market, the trading parties would at minimum know if they need to buy or sell power in the other market, or whether they actually made a trade (Madlener and Kaufmann, 2002). The difference in market closure times implies that information on the availability of supply and the level of demand, so expected prices, would arrive after the submission of bids in a certain hour. In this case and by that time, a given trading party would be committed to selling power into a market that was not expected to enjoy a surplus, so would be trading at a deadweight loss.

Yet even in the case where market deadlines are identical and bids are based on the same set of information, individual traders will not have all of the required information to make a perfectly efficient trade. Hence, by submitting one unconditional bid to buy and one unconditional offer to sell, it is possible to avoid unmatched commitments, ensuring trade occurs regardless of the prices on each market. While high and systematic price differences would mean that these trades are consistently successful, if the markets have similar prices, it is likely for some traders to commit to unexpectedly unprofitable trades.

ACER (2017) found that cross-zonal capacity was used more efficiently in 2016 on borders where capacity was allocated by using implicit allocation methods, with 61% efficiency. In contrast, explicit or other allocation methods led to an efficiency of 40%.

In coupled markets, the two system operators are effectively the trading parties. Here, markets close at the same time, with all bids and offers drawn from the same set of information. Through computer algorithms, power is transferred from the lower- to the higher-priced market until the price differential falls to zero or the interconnector capacity is fully used. Generators and loads all share the same local price, and the price differential determines revenue for the interconnector owner. As information from all market players is used to derive all prices, trade efficiency is maximised.

Price convergence may not be possible in case full capacity is attained. So, either prices converge (in which case the trade volume is below full capacity) or they do not, which means it is profitable to trade, so traders keep trading until all of the capacity is used. In other words, the efficiency of market coupling can be described by the relationship between price differentials and utilisation of the interconnector capacity, which is reflected in either of the two situations, both of which are shown in Figure 2.1.

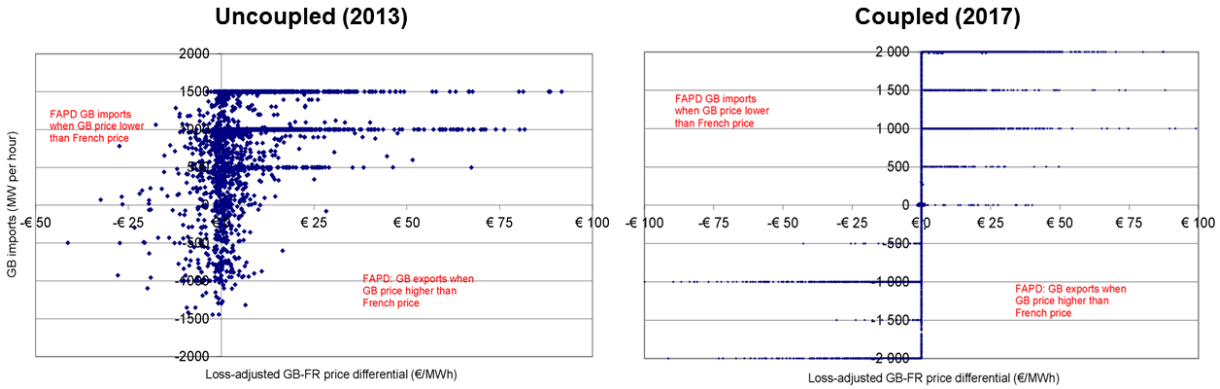

Figure 2.1. GB net imports vs price differences on the IFA interconnector between GB and France before and after the 2014 implementation of EUPHEMIA. FAPD means flows against the price differential.

Figure 2.1 shows the combinations of net imports and loss-adjusted price differences relating to trades over the IFA interconnector between GB and France before and after the 2014 implementation of day-ahead coupling through EUPHEMIA. In the coupled case, price differences are typically less than €1/MWh when capacity is not fully used and only increase when the capacity is fully used. The figure presents the raw data for interconnector capacity, meaning that it does not account for the possibility of unavailable interconnector capacity, such as when in 2017 a major incident affected the IFA connector, with the anchor of a vessel cutting half of the transfer capacity. There are horizontal bands of observations at multiples of 500 MW, which suggests these are efficient uses of the available capacity, and several examples of other intermediate capacities, suggesting periodic partial de-rating of one or more cables. It should be noted how there was virtually an absence of Flows Against the Price Difference (FAPD), with electricity flowing in the correct economic direction.

The pre-2014 situation is quite different and clearly shows strong deviations from the perfect trading described earlier. There are persistent price differentials even with no capacity restrictions, which suggests that trading was not performed in a fully efficient manner. There were numerous periods where electricity flowed in the wrong direction, from the high to the low-priced market, which is when not trading at all would have been the optimal decision. Possible reasons for such inefficient use of the interconnector were investigated by Ehrenmann and Smeers (2005), Bunn and Zachmann (2010), Ehrenmann and Smeers (2004), and Geske *et al.* (2018), and include: uncertainty from the separate energy and transmission markets, system operators being required to schedule cross-border flows for congestion and system balancing, and strategic trading by generators with market power.[9]

By combining the energy and transmission markets, market coupling would remove this uncertainty, thereby causing price differentials to be minimised. This would avoid trades flowing in the wrong direction. The past welfare losses of uncoupled markets and short-term welfare gains from market coupling can be estimated in several ways and are considered in Chapters 3 and 5.

[9] In this case, generators could trade against the price differential by selling into a lower-priced market to raise demand and prices in the domestic market.

2.7.4 Illustration of trading timeline

In this section we will illustrate the effect of coupling with an example of a single participant trading 20MW between France and Great Britain for delivery day 3 June 2018. The first scenario assumes coupling is in place (Table 2.4), while the second scenario occurs before coupling was introduced (Table 2.5).

Scenario 1: Trading between Great Britain and France with coupling.

Date/time	Action
25 Jan 2018	Buy forward 20 MW France electricity for 3 June 2018[10]
15 March	Sell forward 20 MW GB electricity for 3 June 2018
3 May	Buy forward 20 MW France->GB interconnector capacity for 3 June 2018
2 June 12:00 CET	Electricity and capacity released to the coupled day-ahead market. For 20 hours price in GB> price in France, capacity automatically used For 4 hours price in France> price in GB, capacity not used Positions closed out optimally

Table 2.4. Example of trading between GB and France *with* market coupling.

Scenario 2: Trading between Great Britain and France without coupling.

Date/time	Action
25 Jan 2018	Buy forward 20 MW France electricity for 3 June 2018
15 March	Sell forward 20 MW GB electricity for 3 June 2018
3 May	Buy forward 20 MW France->GB interconnector capacity for 3 June 2018
2 June 09:30 CET	Choose to schedule flow on 3 June based on view that UK prices are likely to be higher than France.
2 June 12:00 CET	For 20 hours price in GB> price in France, capacity used profitably For 4 hours price in France> price in GB, capacity used unprofitably

Table 2.5. Example of trading between GB and France *without* market coupling.

The key difference between this scenario and the previous is that here, the participant must decide at 9:30am on the day-ahead which hours of long-term capacity to schedule, before the day-ahead prices are known. In this example, four of the hours are flowed unprofitably.

2.8 The effect of decoupling the interconnector markets

The UK Government has advised that its Departure from the European Union (DFTEU) may lead to alternative trading arrangements between Great Britain and the EU. These arrangements may not include the present coupled day-ahead markets.[11]

In the absence of coupling, long-term capacity holders would likely be required to manually schedule their capacity one or two days ahead, before the day ahead prices were known. This prevents these capacity holders from being able to ensure flow from low price to high

[10] These first three forward trades of electricity and capacity would likely be part of transactions for the whole month of June 2018.

[11] https://www.gov.uk/government/publications/trading-electricity-if-theres-no-brexit-deal/trading-electricity-if-theres-no-brexit-deal

price regions. It is also, however, likely to increase the divergence between the day-ahead prices in the two markets, thus increasing the potential revenue for capacity holders who are able to successfully predict the direction of flow. It is also likely to increase the opportunities to profit in the intra- day capacity markets, as participants are able to correct for flow that has been incorrectly scheduled from what transpires to be high price to low price regions.

The interconnector operators may also create additional opportunities for capacity to be optimised. They could allow capacity owners to adjust the schedule for long-term capacity that was previously scheduled, increasing the value of this capacity. In addition, mechanisms resembling intraday coupling could be established, allowing intraday capacity holders to simultaneously buy in one market, sell in another, and flow, in order to make the most efficient use of available capacity close to delivery.

2.9 Relationships between markets

This section surveys the existing literature on the relationships between the different electricity markets in which European wholesale electricity participants trade. These include markets in distinct geographical regions. It also includes markets at different timescales: from forward markets which trade years before delivery, day-ahead auction markets, intra-day markets which run from the day-ahead auction until shortly prior to delivery, through to markets for balancing and ancillary services. There are interactions between these markets. Participants can buy (sell) in one market and resell (buy back) in a later market. Interconnector capacity can be bought to flow between regions, reducing price differentials. While there are differences in market design in different regions, and a differing mix of generation capacity, there are also efforts underway to increase integration (ACER, 2018).

This literature review is organised as follows. Section 2.9.1 begins by exploring the relationship between day-ahead auctions, which have a high degree of liquidity, granularity and transparency, making them ideal for analysis. Moving closer to delivery, we then turn to intra-day markets in Section 2.9.2 and then to markets for balancing and ancillary services in Section 2.9.3. Section 2.9.4 considers how day-ahead, intra-day and balancing markets interact. Finally, in Section 2.9.5 we consider forward markets, and in Section 2.9.6 the relationship between forward and day-ahead markets.

2.9.1 Relationship between day-ahead markets

Day-ahead auctions occur simultaneously in most European electricity regions. These auctions collect large numbers of bids and offers in order to determine an hourly clearing price for each region. Therefore, these auction results provide a significant source of reliable and comparable data for analysis. A number of authors have explored price data to discover evidence of market integration between European electricity day-ahead markets. Kalantzis and Milanas (2010) examined prices in European markets from 2006-2009 and reported evidence of increasing convergence. Castagneto-Gissey *et al.* (2014a) used a novel model of market integration, dynamic Granger-causal networks, allowing changes to be identified. For example, implementations of the Third Energy Package by the European Commission in

2012 coincided with an observed increase in integration as shown by the model. Gugler *et al.* (2018) also report an increase in market integration between 2010 and 2012 but note a subsequent reduction from 2012 to 2015. They conclude that increased investment in interconnector capacity and greater coupling is required. Keppler *et al.* (2016) note that periods of increased renewable generation in Germany coincided with greater price divergence with France, however this was mitigated by the introduction of coupling. Annan-Phan and Roques (2018) similarly examine market integration between Germany and France, considering the impact of various levels of wind generation and transmission capacity.

Other literature has considered the way that cost elements, such as coal, gas and carbon, are passed through into day-ahead prices, as this explains many of the similarities and differences between prices in different markets. Castagneto *et al.* (2018) consider regions including Great Britain, France and Netherlands, and study variation between regions and over time in which fuel source determines the marginal price. The impact of carbon prices on day-ahead electricity prices is considered in Zhu (2017), who find a weakening relationship.

2.9.2 Relationship between intra-day markets

Despite the existence of established day-ahead auctions, market participants also need the ability to trade physical power during the intra-day period. This need is not new, as there has always been the potential for generation outages and for unexpected changes in demand. However, ACER (2018) has noted the growth in this need due to the increase in intermittent solar and wind generation.

Most of the literature relating to intra-day markets notes that it has considerably less liquidity than day-ahead markets (ACER, 2018; Ofgem, 2018; Neuhoff *et al.*, 2015). Given the need to increase liquidity, one question that has been considered is whether auctions or continuous trading provide more liquidity. Neuhoff *et al.* (2015) discuss the merits of auctions (which were then being introduced into the German market), and subsequently concluded that auctions had increased overall liquidity (Neuhoff *et al.*, 2016), however they did not fully displace continuous trading. Hagemann and Weber (2015) compare actual intra-day trading volumes in different European countries with those predicted by an analytical model, finding that minor differences in trading rules can make a meaningful difference to trading volumes. ACER (2018) and SEMC (2019) also emphasize the efficiency gains from coupling intra-day markets, which has now been implemented between Great Britain and Ireland, and between several regions in Continental Europe (including France, Netherlands and Belgium).

2.9.3 Relationship between markets for balancing services

Each regional electricity system operator is required to ensure the system remains in balance and operates at a stable frequency. This is done by a combination of real-time electricity markets, and ancillary services in which the system operator enters into forward contracts

for ancillary services. These markets are organized differently in different markets, and change over time, which make it challenging to compare balancing prices in different markets. This may explain the limited academic literature on prices in these markets. ACER (2018) reviews some of the differences in these markets and suggests that there is considerable scope to increase efficiency by improving integration and cooperation between markets. Newbery *et al.* (2016) also highlight opportunities to improve efficiency in the use of interconnectors through the coupling of balancing markets.

2.9.4 Relationship between day-ahead markets, intra-day and balancing markets

Electricity market participants can take physical positions in day-ahead and intra-day markets, closing them out in intra-day or balancing markets. This creates a degree of connection between prices in these markets: day-ahead and intra-day prices are likely to reflect the expected intra-day and balancing prices, and in turn participants are likely to get an indication of expected intra-day and balancing prices from observing the day-ahead auction and intra-day prices. Much of the difference between day-ahead, intra-day and balancing prices can be explained by generator or transmission outages or unanticipated changes in weather conditions.

While ACER (2018) and SEMC (2019) provide some discussion of how these markets interact, there is very little academic literature analysing how prices move between day-ahead, intra-day and balancing markets, and how these movements differ between regions. This is perhaps due to differences in how intra-day and balancing markets operate in different regions, and lower transparency of intra-day markets compared with day-ahead markets.

2.9.5 Relationship between forward markets

While day-ahead, intra-day and balancing markets provide a crucial role in European electricity markets, in fact the majority of trading activity is conducted in forward markets, in which participants trade contracts spanning months, quarters or years, typically months or years ahead of delivery (ECA, 2015). Ausubel and Cramton (2010) describe the value in forward markets in reducing risk as well as supporting investment in generation. ECA (2015) and ACER (2018) compare different European forward markets and consider the impact of market design on liquidity. ECA (2015) identify aspects such as the previously different pool mechanism in Ireland, and obstacles to using interconnector capacity, that limit integration.

2.9.6 Relationship between forward markets and day-ahead markets

Forward contracts can be closed out or settled in the day-ahead markets, and so it is straight-forward for participants to take a position between these two markets. Some of the academic literature therefore examines the extent to which forward prices match average day-ahead prices. Huisman and Kilic (2012) conclude that forward prices contain risk premia in markets based on storable fuel such as gas or coal, but less so with markets based on wind, solar and hydropower. ECA (2015) and Ritz (2016) find, however, that risk premia have

increased as wind and solar have increased as a share of generation. Kristiansen (2004), and Marckhoff and Wimshulte (2009), both examine the Nordic market, in which forward contracts are traded on locational price spreads, each finding significant risk premia. Anderson *et al.* (2007) look at trading behaviour in the Australian electricity markets, also finding significant risk premia as a result of generator market power.

3 The value of GB interconnectors

Interconnectors have value for Britain, providing access to cheaper Continental power, security of supply, and managing increased renewables, prompting proposals for substantial new interconnectors. The EU Target Electricity Model requires interconnector market coupling via Day-ahead and Intra-day Markets. We examine the efficiency and value of uncoupled and coupled trading for the four DC interconnectors to GB, over different timescales from year ahead to intra-day, and the social costs and benefits not reflected in the private benefits. The study focuses on the period between 2013 and 2018. IFA and BritNed have a commercial value of about €500 million/yr and create additional surplus of €25 m./yr. The island of Ireland coupled on 1 Oct 2018, dramatically reducing trading inefficiency. Because the GB carbon tax is not replicated abroad it transfers some €65 m./yr to the foreign share of IFA and BritNed as well as adding distortionary costs when trade flows change. The policy implication is that while further investment in interconnectors appears socially profitable, it is important to harmonise carbon taxes across the EU. If GB departs from the EU and is uncoupled, some of these trading gains would be sacrificed, but other financial markets may alleviate these costs, making policies to enhance liquidity desirable.

3.1 Introduction

The growing literature on evaluating additional interconnectors sets out methodologies for their evaluation.[12] Their value is the increase in consumer welfare plus the decrease in total electricity system costs compared to the counterfactual. The social value measures all costs and benefits at efficiency prices, including all external costs of CO_2 emissions and other pollutants. Private value measures these at possibly distorted market prices. Any cost-benefit analysis must make predictions about future generation and other interconnector investments as well as their interaction. It needs to assess impacts on future emissions that will be affected by fuel and carbon prices. Policies for managing cross-border flows like market coupling, rules on access and access charging, renewables subsidies and the choice of discount rate for these very durable investments can strongly affect the results. It is unsurprising that plausible values for specific projects range from negative to strongly positive.[13] Rather than evaluating future projects, this paper looks at the value of existing interconnectors to GB as they have been impacted by the EU *Third Energy Package* and GB carbon taxes. It quantifies the contributions of market coupling for an important example of controllable DC links and makes the case for wider adoption of an EU carbon price floor.

The EU attaches additional significance to interconnection. It announced €48 billion in priority energy infrastructure in 2018: "Properly interconnected electricity lines and gas pipelines form the backbone of an integrated European energy market anchored on the principle of solidarity. A fully interconnected market will improve Europe's security of supply, reduce the dependence on single suppliers and give consumers more choice. It is also essential for renewable energy sources to thrive and for the EU deliver on its Paris

[12] de Nooij (2011), ENTSO-E (2016b), Meeus et al., (2013a, 2013b), Turvey (2006).

[13] Aurora (2016), de Nooij (2011), National Grid Interconnectors (2014), Pöyry (2012, 2016, 2017), Policy Exchange (2016), Redpoint (2013).

Agreement commitments on climate change."[14] This paper measures both the private and social value of electrical interconnectors to GB, including the value of increased security of supply. The more nebulous concept of solidarity falls into the category of non-monetary benefits.

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

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

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

The early debates about the *Third Energy Package* demonstrated the inefficiency of interconnector use to argue for reform, specifically to change from ATC calculations to a flow-based market coupling model (e.g. KU Leuven, 2015). Newbery *et al.* (2016) estimated the potential benefit to the EU of coupling interconnectors to increase the efficiency of trading day-ahead, intra-day and sharing balancing services efficiently across borders. Their report for DG ENER (Newbery *et al.*, 2013) provided estimates for the EU as a whole, based on evidence from ACER (2014). Adopting the ACER methodology but excluding the apparently miscalculated SEM-GB values (discussed below), Newbery *et al.* (2016) estimated

[14]https://ec.europa.eu/info/news/completing-energy-union-eu-invests-eu48-million-priority-energy-infrastructure-2018-jul-16_en

the value of coupling at the day-ahead stage for a sample of interconnectors at €12,670/MWyr of ATC capacity. Intra-day trading was estimated at a modest 4% of the benefits of coupling day-ahead, and complete shared cross-border balancing (still awaited) might be worth as much as 130% of day-ahead coupling. These estimates would be reduced if improved EU-wide integration improved price convergence and reduced arbitrage gains. Additional gains from reducing unscheduled flows and curtailment would not apply to GB coupled interconnectors.

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

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

This paper uses the more extensive data from the ENTSO-E Transparency Platform[15] for the period after market coupling. It measures the private and social benefits of the existing controllable DC British interconnectors. This is motivated by the rush to propose and commission new interconnectors, the concern that some of the private benefits may arise because of Britain's introduction of a carbon tax on fossil fuel for electricity generation that is not matched by the rest of the EU, and, looming ever larger in public concern, the fear that the benefits of market coupling may be lost (Geske *et al.*, 2018).

This paper argues that:

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

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

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

3.2 Interconnector Trading

The British electricity system is linked to France through IFA (2,000 MW capacity), to the Netherlands through BritNed (1,000 MW), to Belgium through NEMO (since 31 Jan 2019, 1,000 MW), to Northern Ireland through Moyle (maximum 500 MW),[16] and to the Republic of Ireland through EWIC (the East-West Interconnector, 500 MW). Northern Ireland and the Republic form the Single Electricity Market (SEM) so GB has two links to the SEM.

Interconnector capacity is sold forward in auctions held at various moments for year-ahead, season-ahead, quarter-ahead, month-ahead, day-ahead, intra-day (and balancing).[17] The forward contracts, although Physical Transmission Rights (PTR), are sold as use-it-or-sell-it, meaning that any capacity bought in forward markets not nominated in the day-ahead market (DAM) is released into the DAM and the holders of the contracts receive the DAM price difference. In practice, about 90% is sold forward, but all available capacity is cleared in the DAM, which is run at noon (CET) to determine prices for each hour of the following day.

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

After the DAM auction there are a number of intra-day market (IDM) auctions for GB and the SEM, while on the Continental most intra-day trading is conducted continuously on EPEX SPOT. Neuhoff *et al*., (2016) demonstrate that this is inferior to periodic auctions by comparing the German experience with both formats. Finally, System Operators take control

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

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

close to dispatch and may schedule balancing flows across interconnectors, calling on bids from Balancing Responsible Parties. The eventual aim of the Target Model is to clear balancing bids across borders. Section 9 gives more details and analysis of these various markets.

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

The revenue will depend on price differences, but the real value is larger, as the ability for GB to import or export up to 5,000 MW makes a potentially appreciable difference to the market clearing price in both GB and France and reduces the overall cost of meeting demand. This additional benefit is discussed below, together with possible distortions to trade arising through differences in carbon pricing in coupled markets.

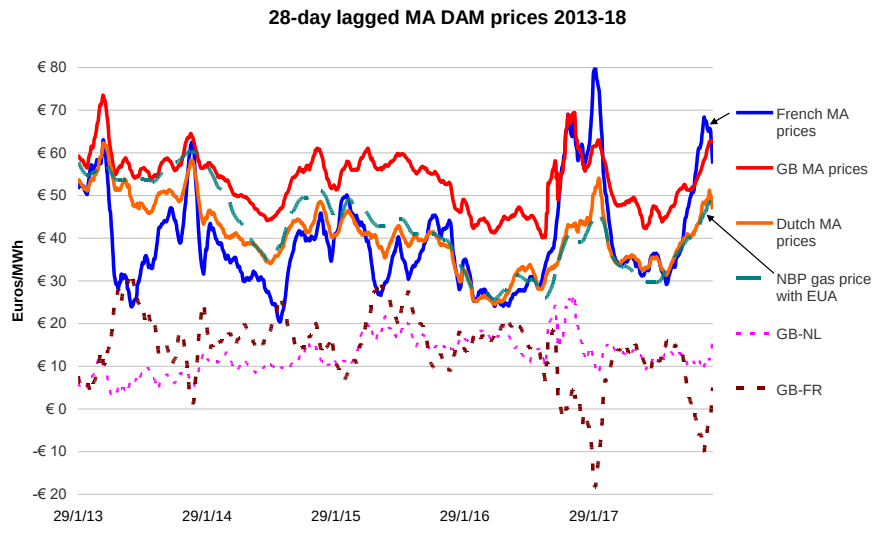

Figure 3.1. Prices in the Day-ahead Market in Britain, France and Netherlands. Source: ENTSO-E Transparency Platform. Note: graphs in same order as legend.

Figure 3.1 shows the lagged 28-day moving average of the DAM hourly prices in GB, France (FR) and Netherlands (NL), as well the cost of generating electricity in a 50%[18] efficient Combined Cycle Gas Turbine, including the cost of the EUA.[19] The gas cost explains some of the price variation, and was a closer match in NL, where gas was likely to be the marginal fuel much of the time, as it was more costly than coal until mid-2018, when the EUA price rose sharply.

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

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

GB and NL have very similar fuel mixes so one might expect similar wholesale prices. Figure 3.1 shows that during 2015-2017, there was a persistent difference with GB on average €14.98/MWh more expensive than NL, while FR is only on average €2.86/MWh more expensive than NL. Over the whole period, GB and NL had price differences of less than €0.5/MWh (effectively the same) 2% of the time, and less than €5/MWh 28% of the time. Price differences across IFA were less than €0.5/MWh (also effectively the same) 19% of the time, and less than €5/MWh 31% of the time.

One potential reason for the higher GB price is that since 2013, GB (but not Northern Ireland) has levied a carbon tax on fuel used to generate electricity (the Carbon Price Support, CPS). In April 2015, the CPS roughly doubled from about £9 to £18/t CO_2, substantially raising the cost of fossil generation. This made coal the more expensive fuel in GB. Chyong *et al.*, (2019) estimated this carbon tax (£18 or €20/t CO_2) would increase the system marginal cost by £5 to £8/MWh from 2015-2017 by identifying the marginal CO_2 emissions in each half-hour (t CO_2/MWh) and multiplying that by the carbon tax (£/t CO_2). Guo *et al*. (2019) estimated that only 60% (SD 12%) of that, or £3 to £5/MWh (an average of €4.5/MWh) of the variable cost has been passed through to GB DAM prices. This only accounts for one-third of the average price excess. As NL is tightly connected to a highly meshed Continental grid, NL prices may be depressed by cheap nuclear French power and high renewable volumes from Denmark and Germany (Blume-Werry *et al.*, 2018; Hirth, 2018).

3.3 The impact of Market Coupling

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

3.3.1 IFA Day-ahead coupling

A standard measure of the success of coupling is that trade flows from lower- to higher-priced zones, and failure is measured by Flows Against Price Differences (FAPD). Figure 3.2 shows trading across IFA in 2013 before the markets were coupled. If the GB price is higher than the French price (adjusted for losses to the half-way point of 1.17%)[20] then GB should import from France (top-right hand quadrant), but if GB prices are lower (i.e. GB-FR prices are negative) then if GB imports it does so in the wrong direction as a FAPD.

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

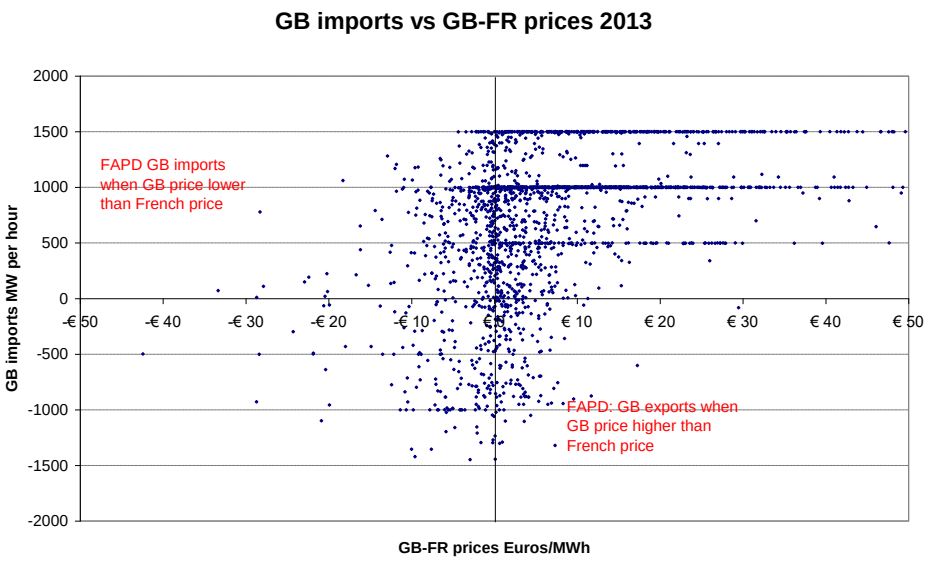

Figure 3.2. Ex post Net GB imports over IFA vs. day-ahead price differences during 2013. Source: GB price from N2EX, FR from EPEX.

It is clear in Figure 3.2 that many observations cluster at multiples of 500 MW, the capacity of each of the four lines. That is because of line restrictions, either because of their unavailability,[21] or because of network limitations within France or GB.[22] Quoting the footnote source "In normal operation, IFA flow is not permitted by the GB Network TSO to change at more than 100MW/minute for frequency management purposes. … Daily Implicit Auctions are expected to utilise IFA capability more fully (function of the daily price difference), thereby causing large hour-hour variations of power transfer more frequently (2GW and vice versa)." If flows were to be reversed, the 4,000 MW change would require 40 minutes to complete. This can explain some of the FAPDs but not all.

The average 2013 GB imports were 1,189 MW at an average GB price excess of €15.83/MWh, giving an average value of €26,405/hr. This is the loss-adjusted price difference times the value of the physical flow, reduced by €3,642/hr because of FAPD. As GB was almost always more expensive than France, the percentage of FAPD was modest at 10% (ignoring small perverse price differences). The value destruction was as much as 14% of the total value of €231 million/yr at €31.9 million/yr.

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

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

Once IFA was coupled the situation changed. Figure 3.3 shows the scheduled flows — the amounts allocated in the DAM auction — in MW against DAM price differences for 2017.[23] ENTSO-E publishes the ATC in each direction, and for lengthy periods 500 MW (one of the four lines), and occasionally 1000 MW was out of service. The clustering of flows at units of 500 MW is very clear and reflects the periodic unavailability of one or more lines. The value of the actual flows using the ATC values for capacity is 99.33% of the maximum feasible flows allowed. Changes in the direction of flows by trading in the IDM and BM occur less than 1% of the time. The value of DAM congestion rent in 2017 was €178 million, with the (loss-adjusted) GB price on average €6.58/MWh higher than in France (roughly half the average for the period 2015-18 shown in Figure 3.1).

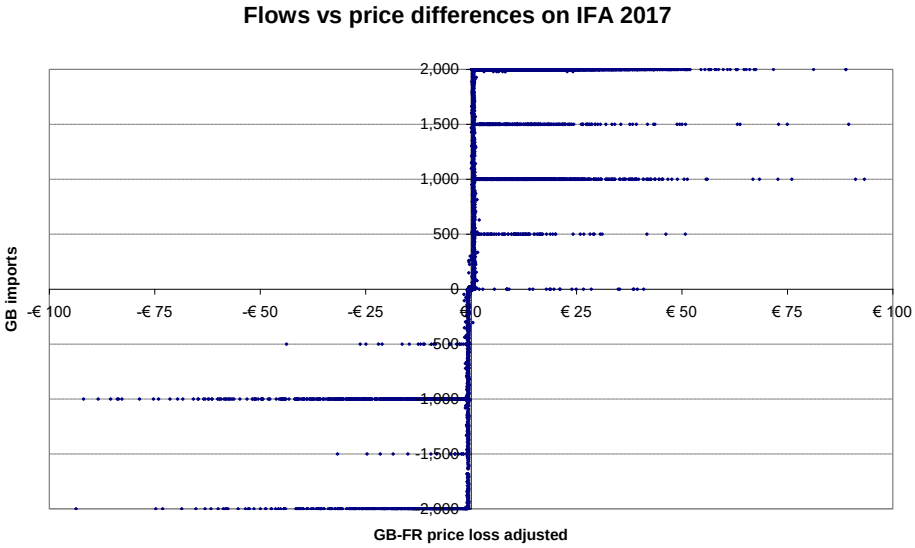

Figure 3.3. Ex ante scheduled net imports into GB over IFA vs day-ahead price differences, 2017. Source: Prices: N2EX for GB, ENTSO-E for FR, data truncated at +/- €100/MWh. Flows are RTE forecast flows.

[23] RTE publishes forecast flows after the DAM auction clears but before flows occur, so they represent the allocation at the DA stage. ENTSO-E publishes scheduled flows that record the actual flows over all timescales including intra-day and balancing and these are used in Figure 3.5 and below to calculate subsequent changes in flows.

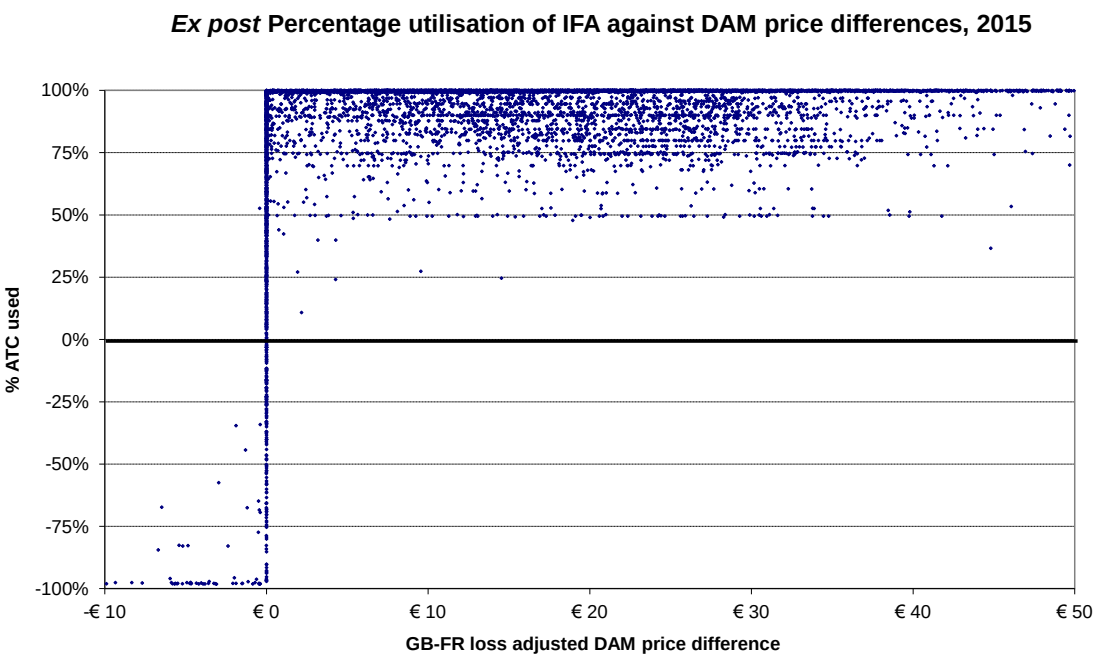

Figure 3.4. Ex post GB net imports from France as a percent of ATC against the GB minus French (FR) price differences, calendar 2015. Sources: Flows and prices from ENTSO-E Transparency platform. Truncated at -€10 and +€50/MWh.

Figure 3.4 shows the percentage of Available Transfer Capacity (ATC) actually used (after further adjustments in subsequent trading on the day) against DAM price differences for 2015. The DAM trading value in 2015 was €270 million (compared to €231 m in 2013).

3.3.2 BritNed coupling Day-ahead

Figure 3.5 shows the scatter of GB exports (or negative imports) against the DAM GB price less the Dutch price for the electricity year (April 1 to Mar 31) 2015-16,[24] adjusted for losses totalling 3%.[25] Again we assume that the DAM clears efficiently, so that all deviations in the actual flow compared to efficient use arise from intra-day and balancing actions. Almost all of the time actual trade is in the same direction as the flows determined in the DAM. The DAM 2015-16 revenue was €135 million, of which €5 million was bought back and re-traded intra-day, discussed in the next section.

[24] There are many missing price values in the first quarter of 2015.
[25] Source: https://www.britned.com/about-us/operations/

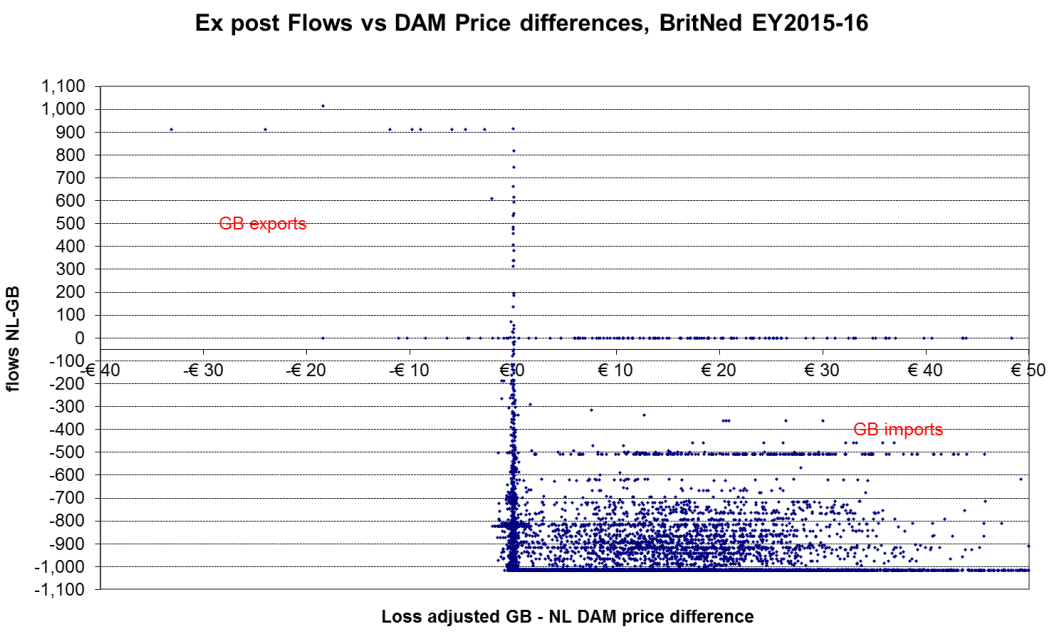

Figure 3.5. Trade vs price difference over BritNed, Electricity year 2015-16. *Note: truncated at €50/MWh.*

Another performance metric is the percentage of potential congestion revenue, assuming the whole 1,000 MW are available 100% of the time. From 2015-18 this measure of efficiency is 95% (€12,276/hr vs €13,378/hr) yielding €107 million/yr. Figure 3.6 shows the evolution of two measures of congestion revenue. The darker line in Figure 3.6 is the loss-adjusted price difference times the scheduled commercial exchanges. Congestion income is defined in Appendix 3.2 and ENTSO-E (2016a). The two measures are clearly quite different, in contrast to the recent IFA experience,[26] and cannot be explained by the difference between scheduled and actual flows (which are small). It may be that it is the result of contracts over different time periods (year, quarter, month, day-ahead, and intra-day) where the contract prices will inevitably differ from the DAM price. Over the whole period the two are almost identical, but the ratio of the DAM revenue to the congestion revenue falls from 268% in 2015 to 63% in 2018. Risk aversion could possibly explain differences in prices traded ahead and intra-day, with an apparent shift from a preference for intra-day risk in the early period to a desire to hedge ahead of time later (perhaps driven by a lack of liquidity in the forward markets). The evolution of these forward markets is considered in Section 3.9.

[26] See ENTSO-E Transparency platform.

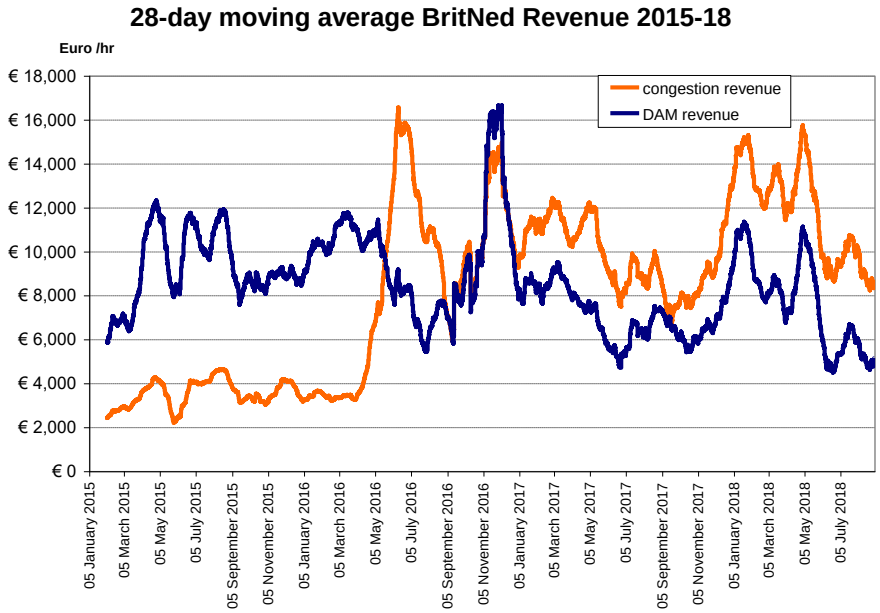

Figure 3.6. Congestion revenue estimated from DAM prices and recorded congestion revenue. Source: ENTSO-E Transparency platform.

3.3.3 The effect of the Carbon Price Support

Guo *et al*. (2019) estimated that the CPS increased net import over IFA in electricity years 2015-2018 by 3.9 TWh/yr, from 7.8 TWh/yr without the CPS to 11.7TWh/yr with the CPS. As France owns half of IFA, the CPS profited French consumers by roughly €26 million/yr. UK consumers paid more, National Grid profited from its share of IFA,[27] and the Government received extra CPS revenue as the CPS is in effect a carbon tax that flows to the Treasury. The estimated impact on Britned's total congestion revenue was to increase it by €33.7 million/yr, about one-third of the DAM congestion revenue under market coupling. Again, this is split equally between National Grid and TenneT.

3.4 Intra-day timeframes

3.4.1 IFA post-DAM trading

Figure 3.3 showed the capacity allocated in the DAM auction while Figure 3.4 showed the actual flows after subsequent trading during the day. There are frequent positive price differences but less than 100% utilisation, because the actual flows are after trading in the intra-day and balancing markets. Coupling implies that if there is a positive (loss-adjusted) price difference in the DAM, the full capacity is allocated at that stage. Subsequently capacity is made available subject to not exceeding the ATC. Thus if GB is importing at 100% of ATC after the DAM auction (2,000 MW), it is only possible to release flows in the IDM from GB to FR, of which 4,000 MW is available. Conversely, if the GB-FR price difference is negative in the DAM, then GB would expect to export, but could buy imports up to 4,000

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

MW after the DAM auction has closed. If the change in direction exceeds the amount bought in the DAM, then there will be an apparent FAPD, based on the DAM prices and the actual flows settled after all the later markets have cleared.

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

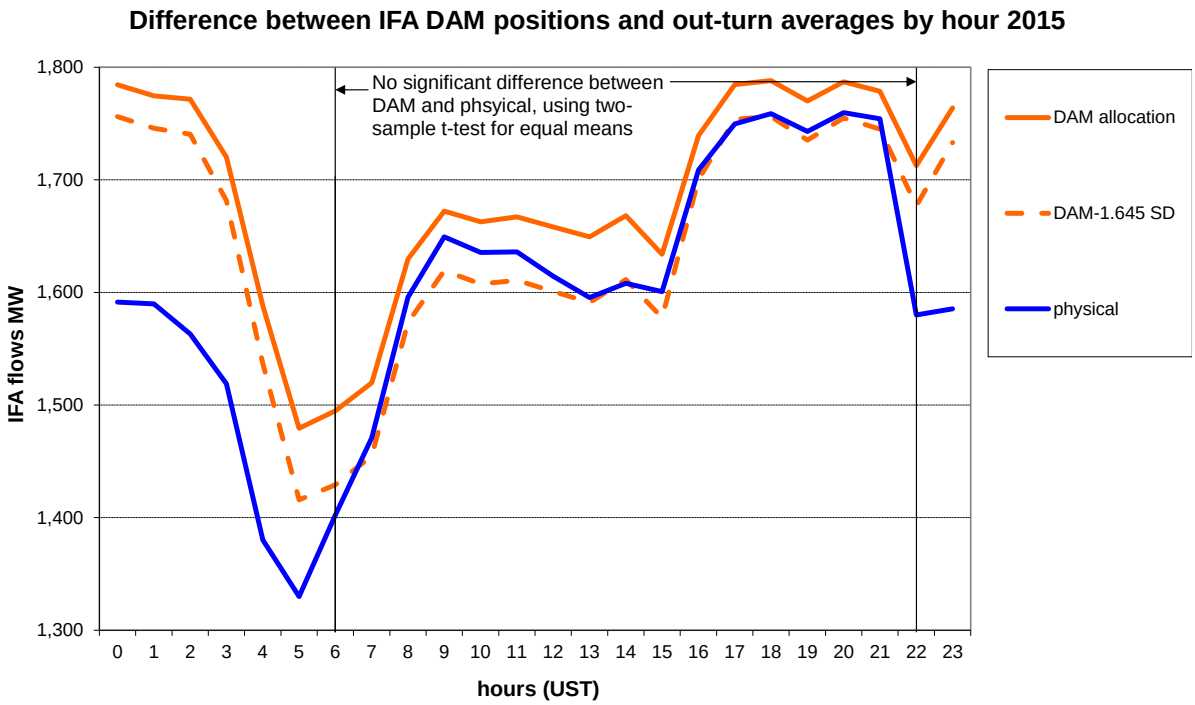

Figure 3.7. Difference between DAM positions and out-turn averages by hour (UST) for 2015. Source: ENTSO-E Transparency platform.

Figure 3.7 shows the difference between the average daily patterns for commercial forecast (volumes cleared in the DAM) and the real (physical) flows after all IDM trades and any balancing actions for IFA in 2015. The one-side 95% lower confidence interval for the DAM

forecast is also plotted as the dashed line.[28] It is clear that the major differences are off-peak night and to a lesser extent early afternoon. An obvious explanation is that GB is constrained by the position its generators need to be in to meet the early morning ramp-up (both to FR for their earlier peak and then for the GB peak). Rather than incur more costly ramping down and then up in GB, imports are reduced as a cheaper flexibility option. Closer examination shows that the main deviations are in the summer months, and that in these hours pumped storage is at maximum demand, while fossil generation is at minimum load. Hence, the main source of flexibility is to reduce imports relative to the earlier day-ahead (or even further back) position. Imports, mainly from France and the Netherlands, have been marginal in GB 13% of the time in 2017 (Castagneto Gissey *et al.*, 2018).

3.4.2 BritNed post-Day-ahead Market trading

We can estimate the value of post-DAM trading from the capacity bought back (or unused when DAM prices are equal).[29] The extra revenue is the difference of the Dutch balancing price[30] less the GBDAM value, times the minimum of the available interconnector value and the net balancing volume in the Dutch balancing market. The 2015 amount is €7 million.

3.4.3 Assessment of coupling

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

3.5 Interconnectors to the Single Electricity Market

Britain has two connections to the SEM, finally coupled on 1 October 2018. Before then flows were highly inefficient, with FAPD roughly 50% of the time since 2015.[31] Before coupling the SEM was a centrally dispatched audited bid pool in which indicative prices were published

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

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

[30] Taking the up-regulation prices.

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

day-ahead on the assumption of no constraints.[32] Settlement took place four days later at the outturn prices based on the actual security-constrained dispatch, typically different from the *ex-ante* prices. About 25% of the time the difference was material. Traders wishing to use the interconnectors therefore based their decisions on inaccurate prices, or alternatively, ignored these *ex ante* prices and flowed according to their forward purchases. ACER (2014) estimate the cost of this inefficiency (for both interconnectors) at €54 million in 2013 and €69 million in 2014, although Newbery *et al.* (2016) considered this a substantial over-estimate. Their estimate for Moyle in 2012 was €7.5 million compared with ACER's (2014) estimate in 2012 of €21.8 million.

Table 3.1 below gives the SEM Committee's (2011) estimates of the potential annual gain in social welfare of using the two interconnectors efficiently. SEM (2011) consulted Moyle interconnector users, finding they identified the deadband as €10-15/MWh between half hourly GB prices and expected *ex post* SEM prices, within which participants would not risk trading. Reasons included the very different gate closure times and *ex-post* pricing in the SEM, the lack of liquidity in day-ahead markets in both Ireland and GB and the risk of incurring Transmission Network Use of System (TNUoS) triad charges. Ofgem removed TNUoS charges for interconnectors users, reducing the deadband. At €5/MWh, the inefficiency would be €30 million/yr for both interconnectors. This intermediate estimate appears defensible.

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

Table 3.1. Moyle and East West interconnectors (950/910MW imports, 580MW exports). Source: SEM-11-023 based on data for 2010 from the Moyle. Note EWIC was not commissioned until 2012.

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

3.6 The value for security of supply

Faced with growing evidence (and good economic theory; Newbery, 2016) that the liberalised electricity market was failing to invest adequately to deliver security of supply (DECC, 2010), the UK Government passed the *Energy Act 2013* (HoC, 2013). Periodic (usually annual) auctions would procure sufficient capacity to deliver the reliability

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

standard of an expected 3 hours loss of load per year (see e.g. Newbery, 2016; Newbery and Grubb, 2015; Grubb and Newbery, 2018). National Grid was charged to recommend the capacity to procure. In the first year National Grid (2014) assumed zero net contribution from interconnectors (but considered sensitivities up to 100% of 2.25 GW imports from Continental Europe). The Panel of Technical Experts,[33] advising on National Grid (2014), drew on reports commissioned by Ofgem and the Government [34] to argue that interconnectors, which are licensed separately and treated differently to generators, "can deliver power to GB and as such they should be treated in the same way as generation, with some probability, to be assessed, that they will be unable to deliver imports during GB stress events."

Subsequently, the European Commission required the UK Government to allow EU generators to bid into the capacity auctions. The compromise interim agreement was that interconnectors could bid. National Grid was charged to calculate interconnectors' de-rated contribution to capacity adequacy. National Grid (2015) estimated these derating factors as 50-70% for IFA, 62-80% for BritNed, and 2-10% for SEM for 2019-20. Estimates for 2022-23 revised these to IFA, 59-86%, BritNed, 27-62%, SEM, 24-42%, and included NEMO (35-67%) and the proposed link to Norway (90-100%).[35] Successful bidders are granted capacity agreements to deliver their de-rated capacity. The System Operator gives those holding agreements 4 hours' notice of a stress period, at which time they are required to be available to be dispatched or face a penalty. However, on 15 November 2018, the capacity agreements were suspended by the EU.[36] The Government is working to ensure they will be reinstated as soon as possible.[37] We assume interconnectors provide capacity value even if not (yet) recognised by EU courts.

This would seem to be easy for interconnectors to deliver. Either they are already flowing to GB (in which case they have delivered their obligation), or the interconnector owner can buy import capacity into GB through the intra-day auction. We can estimate the capacity value of the three interconnectors using the results for the 2016 T-4 for delivery in 2020-21. IFA was awarded 1,193 MW, BritNed 888 MW, and SEM 252 MW. The auction cleared at a price of £22.50/kW/yr giving an annual capacity value for IFA and BritNed of £46.8 million (€57.3 million/yr). Prices in the capacity auction have been volatile. The following year the T-4 auction for delivery in 2021-22 allocated 1,003 MW for BritNed, 1,260 MW for IFA, and 140

[33] Newbery was a member of this Panel but writes in his personal capacity, drawing only on information in the public domain.
[34] Pőyry (2012), Redpoint (2013)
[35] Pöyry, 2018. An update of historical de-rating factors for Great Britain interconnectors, at https://www.gov.uk/government/publications/capacity-market-and-interconnectors-an-update-of-historical-de-rating-factors-for-great-britain-interconnectors
[36] See http://curia.europa.eu/juris/document/document.jsf?text=&docid=207792&pageIndex=0&doclang=en&mode=req&dir=&occ=first&part=1&cid=1430154
[37] See https://www.gov.uk/government/collections/electricity-market-reform-capacity-market?utm_source=ba1f7ca5-ac48-41a8-afbd-9527d207a185&utm_medium=email&utm_campaign=govuk-notifications&utm_content=immediate

MW (just Moyle) for SEM. The auction cleared at £8.40/kW/yr, giving their total capacity value as £19(€22) million/yr for IFA and BritNed (National Grid, 2018). In that auction for the first time new interconnectors were successful: Nemo (GB-BE, 1,000 MW) was granted 750 MW, IFA2 (1,000 MW) 715 MW and ElecLink (1,000 MW, GB-FR) 690 MW.

The fall in auction prices may reflect a smaller amount of "missing money" (Grubb and Newbery, 2018) now that National Grid has defined and procured more short-run flexibility products, but could reflect falling demand and adequate existing capacity. Nevertheless, 4.1 GW new capacity was procured, of which 1.2 GW of demand-side response cleared at this low price.

3.7 Commercial profitability of IFA and BritNed

BritNed cost about £$_{2018}$ 560 million (€640 million) and was commissioned in 2011. Company accounts are available for BritNed[38] and provide a break-down of various sources of income. The 2017 arbitrage revenue was €92 million calculated at DAM prices, but as BritNed sells the larger part forward, actual arbitrage revenues were considerably higher. The company accounts for 2017 (2016 in brackets) show net explicit revenues as €115 million (€174 m), net implicit revenue €16 m. (€20 m.) and "other revenue" (defined as the value of the frequency response service, participation in the GB Capacity Market and other minor ancillary services such as Intertrip services) as €15 m. (€14 m). Administrative expenses were €32 million. Operating profits (after admin expenses) in 2015 and 2016 were over €200 million, or a net private rate of profit of over 30%.

Table 3.2 summarises the DAM arbitrage revenue for IFA and BritNed during electricity years 2015-2018. However, the company accounts show actual revenues from forward and spot trading at 140% of the DAM value in 2017 and 134% for 2016, shown in Table 3 as additional forward trading value to be added to the value at DAM prices. Given that flows over IFA are probably more predictable, this additional revenue may be smaller and also appear from Fig. 10 below to be converging on the DAM value. We take a conservative additional 10% for forward trading on IFA. The three-year average for the two interconnectors is €375 million/yr at DAM prices, or about €125 million/GW/yr over the longer period 2015-18, or €125/kW/yr.

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

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

Table 3.2. Day-ahead Arbitrage for IFA and BritNed in € million, electricity years 2015-2018.

Table 3.3 reports the various sources of commercial value. It is hard to be more precise than that IFA and BritNed contribute a capacity value of between €22-57 million/yr, or between 6–15% of their DAM arbitrage value. Our earlier estimate shows that the intra-day value is about 3% of DAM value, or about €10 million/yr. Forward trading for BritNed (and presumably IFA) considerably increases the revenue received by interconnectors, perhaps by €50 million/yr for BritNed and €25 million/yr for IFA. Netting out the capacity payments from other payments in the accounts suggests very modest values for balancing and ancillary services, or a notional €5 million/yr for both interconnectors taken together. Table 3.3 summarises a central value (around which there must be considerable uncertainty) for the annual commercial value of trading over IFA and BritNed in 2015-2018, just under €170/kWyr.

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

Table 3.3. Commercial value of trading over IFA and BritNed in € million/yr.

3.8 The social value of interconnectors

Profitability is only a good measure of social value if prices are not changed by the interconnector flows and the prices measure social costs and benefits. Neither is currently true for GB trade. Table 3.3 estimated the commercial profitability, not the social profitability, as it includes the extra revenue from the asymmetric application of a carbon tax in GB, but not on the Continent. The French may claim to be delivering nuclear-fuelled electricity over IFA, but whether that is the marginal source is less clear, as either France will be importing from fossil-intensive neighbours or exporting less nuclear power there and inducing more fossil generation to meet demand. Castagneto Gissey *et al.* (2018) estimates the French marginal share of carbon-intensive generation was 11% between 2015 and 2017, supporting this assessment.

Blume-Werry *et al.*, (2018, fig 2.) suggest that 75% of the time foreign generators set the Dutch price. In their 2020 simulation, gas sets the price 35% of the time, coal 18% and very carbon-intensive lignite 11% of the time, with the balance zero-carbon sources (nuclear, hydro and RES). If coal is twice the carbon intensity of gas, and lignite three times, then the

effective carbon intensity of Dutch electricity might be 0.35 tonnes/MWh and this would add roughly €7/MWh to the social cost[39] of Dutch exports to GB, or about the same as the CPS added to GB electricity. This would increase the cost of GB imports from the Netherlands by about €50 million/yr, assuming no change in trade (i.e. because the Netherlands does not impose this carbon tax), reducing social profits in 2017 to €63 million, and giving a net rate of return of 10%.

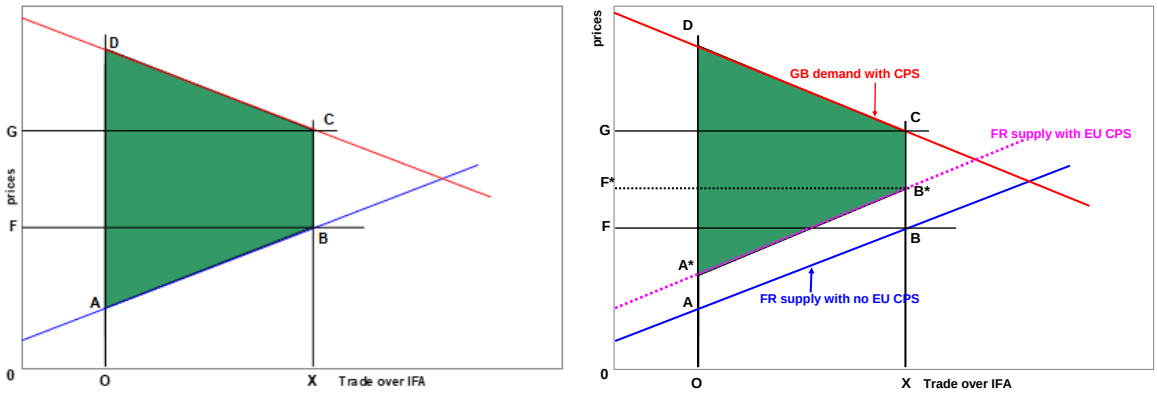

Figure 3.8. Trade over interconnectors at market prices (left panel) and with (right) EU CPS.

In Figure 3.8a (left panel) AB is the supply curve of FR exporting over IFA in the DAM to GB, and DC is the demand by GB to import over IFA (including the CPS, taken here as the correct additional tax to add to the EUA to give the social cost of carbon). The maximum export over IFA is OX, and the DAM clears at a French price of G and at a GB price of F. The value of trade is FG * OX, but the full social value of the interconnector is the area ABCD, which has a value ½(AD + CB) * OX. The revenue thus understates the social value by the difference between these two areas.

To give an approximate estimate in the case of IFA, if GB prices fall by €1/GW extra demand[40] and the French price rises by €0.5/GW, then the difference between prices with no trade and with the full 2 GW of trade is €3/MWh if after coupling the full 2 GW are used. The extra uncounted social value would then be ½ x €3/hr x 2,000 MW or €3,000/hr. More generally, if prices converge after coupling, and the volume traded is *X* MW, the missing social value will be ½ €1.5.X/1000*X/hr. In 2015, the average volume of trade was *X* = 1,641 MW, so in this case the average missing social value was €2,020 /hr, or €17.7 million/yr. For BritNed, the average physical flow in 2015 was 929 MW. If GB prices fall by €1/GW of demand and NL prices raise by €1/GW, then the average missing social value was €863/hr, or €7.6 million/yr.

Figure 3.8b shows the potential distortion that arises when GB imposes a carbon tax (the CPS) while its trading partner does not. If this distortion were removed by the EU imposing

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

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

the correct CPS, then the French supply schedule would shift up from AB to A*B*. The French price would rise to F* and the value of trade would fall to (F*G)*OX and the social value would be less than the market value (at distorted prices) by the area AA*B*B, leaving the shaded area as the correct social value of the interconnector.

If the French price is set in Germany, then based on the German marginal share of energy generation in 2016 (from Castagneto-Gissey *et al.*, 2018), and using the carbon intensity provided by Grid Watch[41], an EU-wide CPS would raise the French price by an average of €7.38/MWh, slightly lower than an increase of €9.41/MWh for GB prices (using the same data source). The average volume traded in 2016 was 1,147 MW, the effect of the GB CPS alone is to increase congestion income by €95 million, which is paid by the GB citizens and equally split by both RTE and the National Grid. If an EU-wide CPS is implemented, congestion income would only rise by €21 million, a reduction of €74 million.

3.9 Forward trading over interconnectors

Forward trading predates market coupling. Before 2014, forward contracts were for rather illiquid Physical Transmission Rights (PTRs) that did not allow financial settlement. After coupling, PTRs allowed the possibility of financial settlement more similar to a Financial Transmission Right (FTR). These became more liquid, operating effectively as CfDs, as shown in Figure 3.9. If the UK were no longer able to access EUPHEMIA after leaving the EU, then forward trading would no longer offer the possibility of financial settlement. This section examines what other contract markets might be able to replicate the benefits of financial settlement, reducing the cost of uncoupling.

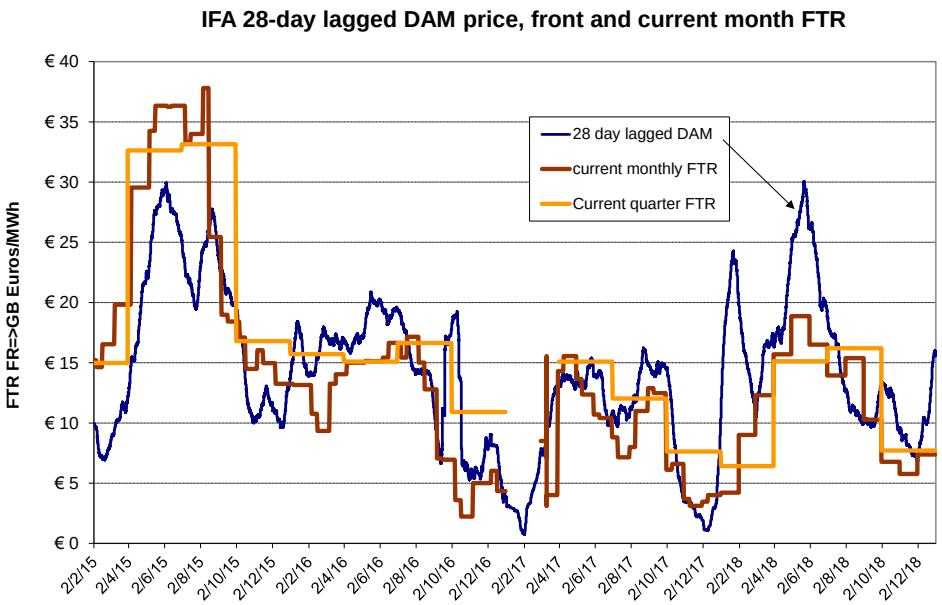

Figure 3.9. PTRs (labelled here as FTRs as they allow for financial settlement) and lagged DAM price differences over IFA. Note: Contracts are traded on typically two days each month.

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

PTRs are auctioned ahead of delivery for periods of years, quarters, months and weeks at various dates during the year. For IFA,[42] there are two auctions for annual contracts held in the middle of the first and third week of July the year before, and a third one in the middle of August. There are typically two auctions for the month ahead, for the quarter ahead held one or two months before, for the summer ahead held in Jan and Feb, and for the winter ahead in April and May. For IFA 93% of the available 2,000 MW are sold forward, of which half is for the calendar year.

PTR auction clearing prices for IFA and Britned are publicly available.[43] Figure 3.9 shows the lagged 28-day moving average of the DAM GB – FR price differences and the PTRs for the current month (sold the month before) and the current quarter.[44] As PTRs are options only exercised if profitable, they are compared with the moving average of the positive values of hourly price differences.

In 2015, the PTRs sold at a premium to the underlying product (the DAM price difference) but thereafter they appear to have converged, with if anything some undershooting. The PTRs give the right to import but losses mean that they are actually worth somewhat less than their price, which ignores losses.[45] Appendix 3.1 gives tables showing the auction outcomes for both IFA and BritNed, showing the ratio of the latest (and presumably most accurate) auction price to the outturn. Thus for the 2015 monthly auctions the average ratio for IFA is 1.35 and for BritNed is 1.36 with coefficients of variation (CV) of 22% and 18%, whereas the hourly CV over the whole year for price differences across IFA is 83% (81% for BritNed). The 2015 annual and quarterly auctions show a larger ratio or risk premium, as the hedge is taken under greater uncertainty about the future market conditions. Forward trading over the two interconnectors seems to be remarkably similar in risk aversion. However, by 2016 it would be hard to reject the hypothesis that the quarterly auctions exhibit no risk premium.

3.9.1 Comparing PTRs and hedging on local power exchanges

It is also possible to buy power forward in both France and GB (and NL, but we focus on France and GB) and replicate a PTR with CfDs. Indeed, Nordpool used CfDs to hedge zonal price differences rather than PTRs (Lundgren and Forsberg, 2016). Figure 3.10 compares the two instruments for 2016-18 for selling from France to GB against the DAM monthly average for the delivery month. The auctioned PTRs are only issued at two points in the month (assumed here to be the first and second or third Thursday), hence PTR I and PTR II,

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

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

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

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

whereas the CfDs for the named month are traded actively on workdays for several months ahead (as shown in Appendix Figure 3.A1). Here the CfD price differences on the dates of the PTR auction are shown as CfD I and CfD II. There appears to be considerable convergence after the first year (2015) except for December 2016, when French nuclear stations were off-line. Even if uncoupling meant PTRs no longer allowing the possibility of financial settlement, CfD markets in neighbouring countries (including NordPool, which already provides CfDs internally) should offer additional hedging, facilitating efficient flow and reducing the cost of uncoupling. More generally, exit from pan-European algorithms such as EUPHEMIA would reduce trading efficiency that other trading hubs provide, yet these other hubs might compensate some of the uncoupling losses.

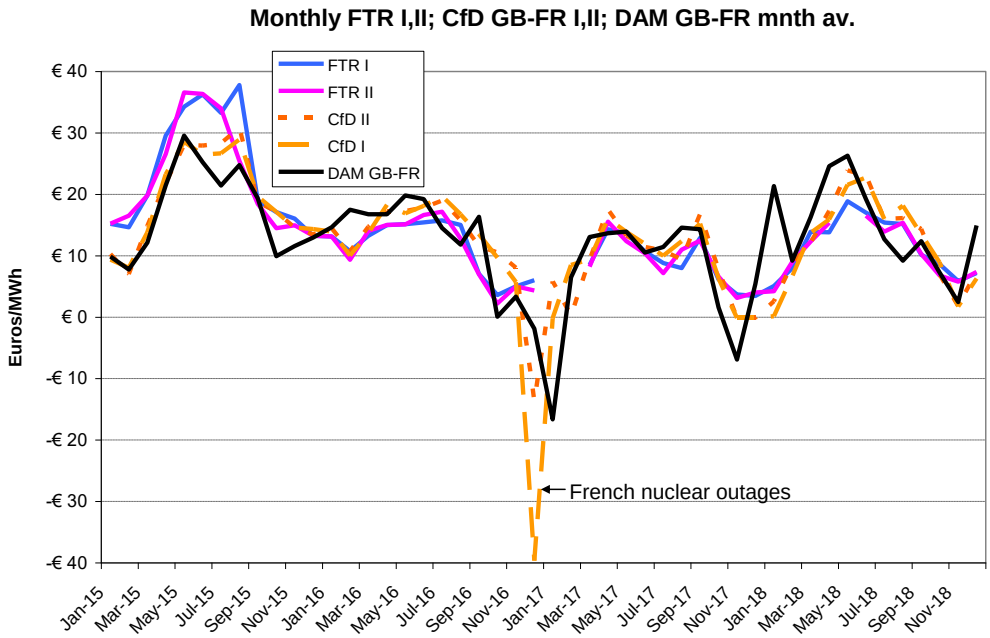

Figure 3.10. Comparison between hedging across IFA using local power exchanges and PTRs (labelled here as FTRs as they allow for financial settlement) compared to monthly DAM price differences for the delivery month. Source: Bloomberg and ENTSO-E.

3.10 Conclusions and policy implications

We explored the efficiency of trading on the Day-ahead Market (DAM) auction platform before and after market coupling, and established that market coupling has indeed created efficient trading at the day-ahead stage on IFA and BritNed. The Single Electricity Market (SEM) of the island of Ireland was finally coupled on 1 October 2018 and since then the DAM auctions have efficiently used the interconnectors.[46] Before that, it was trading inefficiently, with flows in the wrong direction almost half the time, and losses that the regulators estimated for 2010 as €30 million/yr. ACER claimed even larger losses. The

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

arbitrage revenue for trading capacity on the DAMs for IFA and BritNed averages about €125 million/GWyr, or €375 million/yr for both.

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

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

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

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

As of May 2018, the future relationship of GB with the European Union is unclear. Market uncoupling could lead to a loss of some of the previously accrued coupling benefits (including more efficient trade), although trading CfDs on neighbouring power exchanges supplemented by PTRs (as used before coupling) might continue to deliver most of the trading benefits. There would seem little to prevent setting up a similar DAM and IDM in GB for trading over the interconnectors, although sacrificing some gains from a pan-European simultaneous auction. It might even allow possibly better auction bid formats that more closely reflect the operating realities.[47] Enhancing liquidity and transparency of such markets is clearly desirable whatever happens to the UK's relationship with the EU.

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

4 The impact of a unilateral carbon tax on trade

Market coupling makes efficient use of interconnectors by ensuring higher-priced markets import until prices are equated or interconnectors constrained. A carbon tax in one of the markets can distort trade and reduce price convergence. We investigate econometrically the impact of the British Carbon Price Support (CPS, an extra carbon tax) on GBs cross-border electricity trading with France (through IFA) and the Netherlands (through BritNed). Over the period 2015-2018, the CPS would have raised the GB day-ahead price by an average of about €10/MWh in the absence of compensating adjustments through increased imports. The associated impact of the CPS on GB domestic electricity bills is derived in the Annex attached to this report. The actual price differential with our neighbours fell to about €8/MWh allowing for replacement by cheaper imports. The CPS increased GB imports by 13 TWh/yr, thereby reducing carbon tax revenue by €103 million/yr. Congestion income increased by €133 million/yr, with half transferred to France and the Netherlands. The unilateral CPS created a €28 million/yr deadweight loss. About 18% of the increase in the GB price caused by the CPS was passed through to higher French prices and 29% in higher Dutch prices. Yet the CPS has led to an unprecedented reduction in coal generation and the first coal generation-free day in GB since the industrial revolution. Applying the tax across the wider Continent should therefore induce deep decarbonisation at scale, whilst eliminating the costly trade distortions we identified.

4.1 Introduction

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

In 2011, the UK government decided to enact a gradually escalating carbon price floor for fossil generation fuels to make low-carbon generation investment commercially viable. This came into effect in April 2013 and took the form of a carbon tax (the Carbon Price Support, CPS, an addition to the EU carbon price, see Figure 4.2) on generation fuels in Great Britain (but not Northern Ireland).

This paper studies the impact of asymmetries in carbon taxes between connected countries on cross-border electricity trade. It takes Great Britain (GB) as a case study and demonstrates how the unilateral imposition of a carbon tax affects electricity prices, interconnector flows, congestion income (from the difference in price across congested interconnectors), and deadweight loss. We estimate that over 2015-2018, when the CPS stabilised at £18/tCO_2, the CPS would have raised the GB day-ahead price by an average of about €10.5/MWh in the absence of compensating adjustments through increased imports. The actual price differential with our neighbours fell to about €8.5/MWh after allowing for replacement by cheaper imports. The CPS increased GB imports by 13.6 TWh/yr, thereby reducing carbon tax revenue by €113 million/yr. The commercial value of interconnectors, measured by

congestion income increased by €133 million/yr, half of which was transferred to France and the Netherlands. The commercial value understates social value by ignoring infra-marginal surplus valued at around €30 million/yr, but the CPS created deadweight losses of €28 million/yr. About 18% of the increase in the GB price caused by the CPS was passed through to higher French prices and 29% in higher Dutch prices.

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

4.1.1 Literature review

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

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

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

4.2 Market coupling

Starting from 4 February 2014, electricity market coupling in North Western Europe went live. Great Britain, France, and the Netherlands took part in this initiative, while on the island of Ireland the SEM was not integrated until 1 October 2018. For that reason we limit our attention to trade with our Continental neighbours, France and the Netherlands. Following market coupling, bids to buy and offers to sell are fed into a European-wide auction, which operates using the EU Pan-European Hybrid Electricity Market Integration Algorithm (EUPHEMIA) algorithm.

Each market operator solves for its own area price at which the area's supply and demand equate. When different market prices across the interconnector occur, EUPHEMIA yields a

"price-independent purchase" in the low-priced area and a "price-independent sale" in the high-priced area, corresponding to the interconnector's Net Transfer Capacity (NTC). As a result, prices in the higher-priced market decrease, and prices in the lower-priced market increase. If the prices do not converge, then the entire NTC is allocated and prices remain different in the two zones, but if the prices can be equilibrated with a smaller flow than the NTC, that flow is allocated to create a single price zone across the interconnector, *integrating* the connected markets.

4.2.1 Electricity trading between connected markets

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

Interconnector capacities are similarly sold forward in auctions for Transmission Rights held at various timescales ranging from year-ahead, to season-ahead, quarter-ahead, month-ahead and day-ahead. Once markets are coupled, the day-ahead market becomes an implicit auction for all participating countries. The price realised in this implicit auction is then used to clear all forward contracts, with physical contracts reverting to financial rights. In addition, adjustments after the closure of the day-ahead market (DAM) are cleared in the intra-day markets.[48]

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

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

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

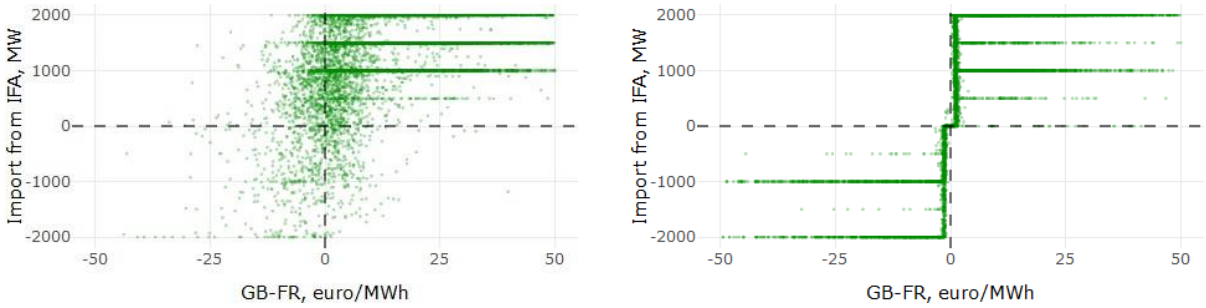

Figure 4.1. Day-ahead scheduled commercial exchange of IFA flows v.s. GB-FR price differentials, before and after market coupling. Source: Day-ahead scheduled commercial exchange from RTE; day-ahead GB prices from Nord Pool; day-ahead French prices from EPEX Spot.

Figure 4.1 plots the day-ahead scheduled commercial exchange (SCE) of net imports (exports shown negative) over the Interconnexion France Angleterre (IFA) between GB and France, before and after market coupling. There are four cables of 500 MW each for a total of 2 GW, hence the horizontal bands of observations at multiples of 500 MW are due to one or more cables under maintenance or because of network limitations. In 2013, before market coupling (Figure 4.1a), capacity was inefficiently used with many FAPDs, while after market coupling (Figure 4.1b) available capacity was efficiently used with no FAPDs.

The day-ahead scheduled commercial exchange that allocates capacity to the DAM can differ from the final recorded cross-border physical flows because market players can buy and sell intra-day capacity as they receive updates on renewable generation, demand changes and plant outages. The System Operators may also intervene to balance one or both systems, although balancing markets are mostly not yet fully coupled through cross-border markets.[49,50]

The actual flow will be the sum of the day-ahead, intra-day and balancing flows, and any difference between the day-ahead and actual flow should correspond to intra-day and balancing nominations. Intra-day flows may be hedged by buying and selling in the intra-day market, or settled in the balancing market. In this paper, we focus on the day-ahead market and on the GB interconnectors that have been coupled since 2014 (i.e. IFA and BritNed).

4.3 The British Carbon Price Floor

The British Carbon Price Floor (CPF) was announced in the 2011 Budget and came into effect in April 2013. It was intended to make up for the failure at that time of the EU Emissions Trading System (ETS) to give adequate, credible and sufficiently durable carbon price

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

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

signals. The CPS was implemented by publishing a GB[51] Carbon Price Support (CPS) that is added to the EU CO_2 Allowance (EUA) price to increase it to the projected CPF. The CPS grew from £4.94/t CO_2 in 2013 to £18/tCO2 in 2015 (and has been frozen at £18/t CO_2 since then). The total GB carbon cost rose from £5/tCO2 in early 2013 to nearly £40/t CO_2 by the end of 2018. Figure 4.2 shows the evolution of the (nominal) GB and the EU carbon costs in £/t CO_2. The two curves start diverging in 2013, with the gap becoming wider in 2014 and 2015. The dashed line represents the GB carbon cost target when the CPF was announced. It was not until late 2018 that the GB carbon cost finally met the initial trajectory, thanks to the reform of the EU ETS, which introduced a Market Stability Reserve that removes excess EUAs and increases the European Emission Allowance (EUA) price (Newbery *et al.*, 2019b).

Figure 4.2. Evolution of the European Allowance (EUA) price and CPF, £/tCO_2. Source: Chyong, Guo and Newbery (2019).

The CPS raises the cost of fossil-fuelled electricity generation. Figure 4.3 plots the 28-day moving average (MA) of the day-ahead prices for GB, France (FR), and the Netherlands (NL), as well as the price differentials between the two connected markets. It also shows the variable cost (i.e. the short-run marginal cost) for Combined Cycle Gas Turbines (CCGTs) with 54.5%[52] efficiency with EUA prices included (but excluding the GB CPS) as a measure of Continental gas generation costs.

In general, while GB prices are typically higher than NL prices, the CPS widens the GB-NL price differential. FR prices are much more volatile than in GB and NL mainly because nearly 80% (in 2015)[53] of its gross electricity generation comes from nuclear power stations, making its electricity system less flexible than in GB and the Netherlands, resulting in more volatile prices. Another reason for the high volatility is that French prices are very weather-sensitive given their high domestic electrical heating load. During December 2016 and

[51] Northern Ireland, which is part of the Single Electricity Market of the island of Ireland, is exempt to preserve an equal carbon price there.
[52] Measured at Lower Heating Value (LHV).
[53] From Eurostat at:https://ec.europa.eu/energy/en/news/get-latest-energy-data-all-eu-countries.

January 2017, France experienced nuclear outages,[54] which explains the negative GB−FR price differential during that period. The variable cost for CCGTs partially explains the patterns of prices for the three markets, and best fits the dynamics of the Dutch prices, where gas is likely to be the marginal fuel much of the time.

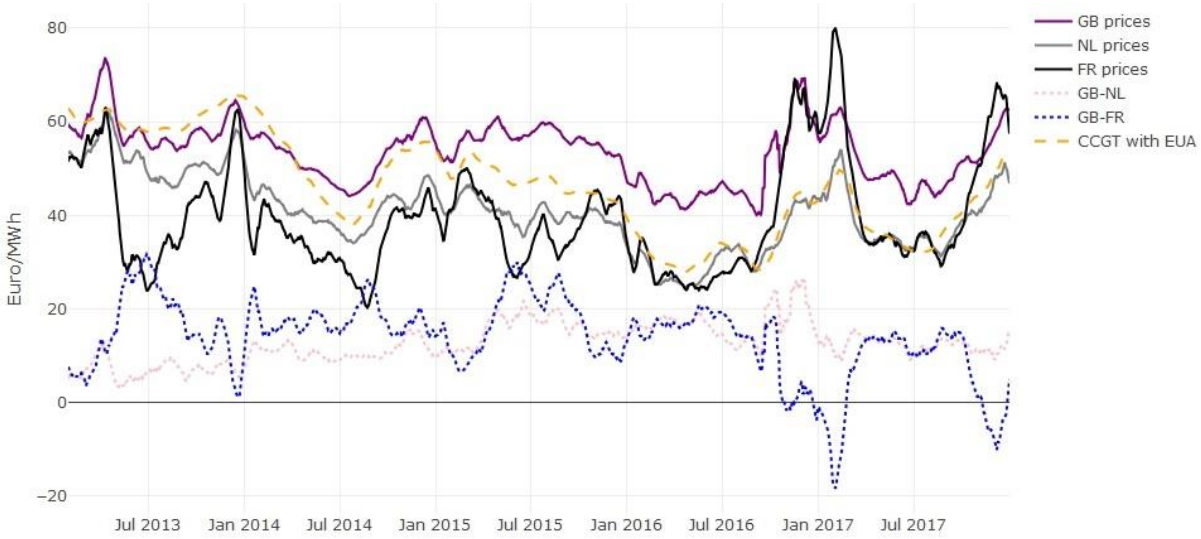

Figure 4.3. 28-day lagged Moving Average wholesale prices, 2013-2017.

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

4.3.1 The impact of a carbon tax

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

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

[54] See https://www.ft.com/content/f86a3c6c-9c60-11e6-a6e4-8b8e77dd083a.

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

Figure 4.4 shows the result of imposing the CPS on GB generators when the import capacity over IFA from France (FR) is KL. If there were no interconnector, the GB price would be PGB where the GB net supply S_0^{GB} meets demand D_0 at I. With the interconnector, the GB net supply curve meets the FR net supply curve at point H, with prices equalised ($P_1^{GB} = P_1^{FR}$), no congestion income and imports ML. Under the assumption of zero consumer demand elasticity (i.e. vertical demand curves), the gain in surplus created by the interconnector is entirely due to a reduction in GB generation costs, offset by a small increase in FR cost, with the net cost reduction shown as the triangle labelled "original market surplus", or HIJ. The triangle HIJ is also known as the *infra-marginal surplus* without CPS.

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

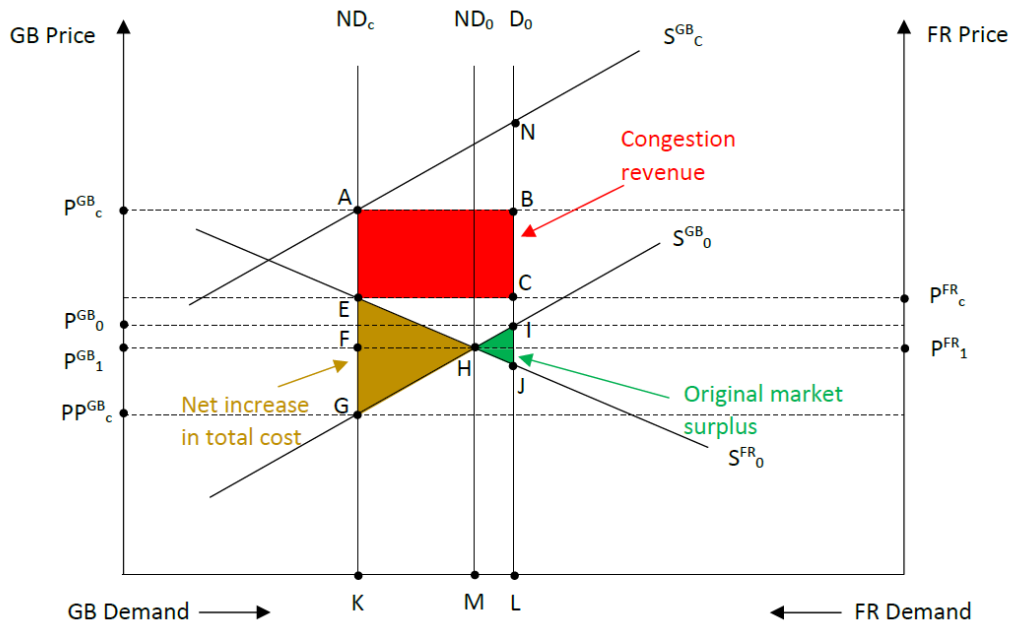

Figure 4.4. Impact of CPS on Imports and Surpluses, GB Imports from Partial to Full Capacity.

The deadweight loss can be estimated if we can measure the GB−FR price differential with the carbon tax (or AE in Figure 4.4) and the impact of the CPS on GB prices (or AG in Figure 4.4). Under the assumption of (locally) linear net supply curves, given the increase in import is KM, the deadweight loss is 1/2×(AG-AE)×KM. The base of the triangle, AG-AE or EG is the sum of the reduction of the GB producer price (P_1^{GB} −PP_C^{GB}) and the increase in the FR price due to its increase in exports (P_C^{FR} −P_1^{FR}). We name this the CPS pass-through to the interconnector, and its ratio to the impact of the CPS on GB prices, or EG/AG, the cross-border CPS pass-through rate.

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

The carbon tax also leads to an increase in congestion income but half of this goes to France. French prices rise from P_1^{FR} to P_C^{FR}, increasing FR generator profits by less that the increase in consumer costs (the difference being the French share of the total deadweight loss).

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

4.3.2 Estimating the impact of the CPS

Figure 4.5 plots the Price Differential Duration Schedules (PDDS) of IFA (GB minus FR, or PDIFA) before (2013) and after (2017) market coupling. The difference between the two curves is that after market coupling, the price differentials cluster around the horizontal line at zero (Figure 4.5b). The reason is that there are many hours for which there is sufficient capacity to equalise GB and French prices, while it is unusual for prices to be the same for the uncoupled 2013 PDDS (Figure 4.5a). The line at PDIFA = 0 is not perfectly horizontal because the prices are equated based on Mid Channel nominations and then adjusted at each end by a loss factor to give prices in each country. Without the British CPS (while keeping the interconnector flow constant) the entire PDDS curve for 2017 (Figure 4.5b)

would shift downwards, as illustrated in Figure 4.5.[55] If the market is then coupled, GB would keep exporting with full capacity at a price difference AB and keep importing with full capacity at price difference CD. The outcome is more complex at price difference BC, where with CPS, GB was either importing or exporting at less-than-full capacity. At BC, if the maximum 4 GW switch (from 2 GW to −2 GW) of the interconnector flow is sufficient to integrate the prices, the price differential for that hour would cluster at zero. If instead the 4 GW is insufficient to equalise the prices, GB would be exporting at full capacity and the price differential would fall to a negative value. For instance, suppose that the impact of flows on the price difference, PDIFA, is €2/MWh/GW and that with the CPS applying, for a particular hour GB imports 0.5 GW and the GB and French markets are integrated. Now, if removing the CPS would cause the GB price to fall by €7/MWh, GB would be exporting at full capacity (2 GW) in that hour. The resulting 2.5 GW shift in the interconnector flow would, as a result of price changes, lead to PDIFA falling back to €−2/MWh (= −7 + 2.5 × 2).

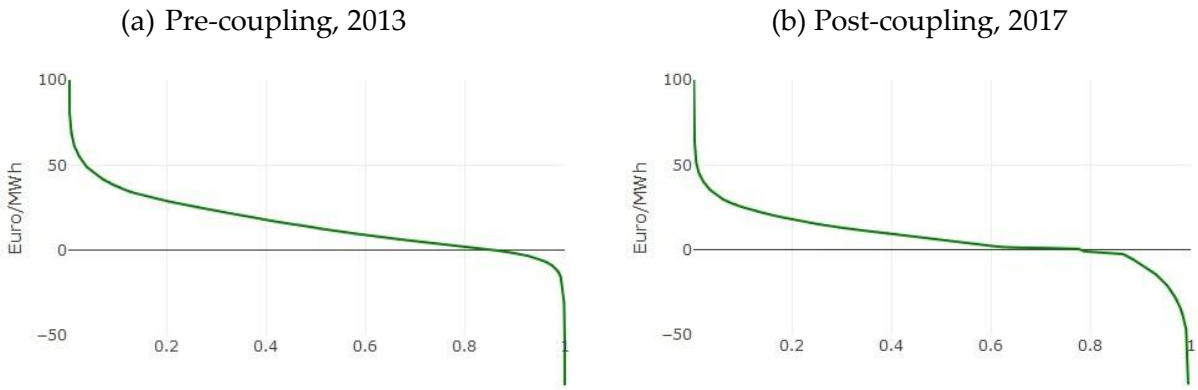

Figure 4.5. Price Differential Duration Schedules for IFA Price Differential (GB-FR), 2013 vs. 2017. Source: Day-ahead GB prices from Nord Pool; day-ahead French prices from Blomberg EPEX Spot.

The example in Figure 4.5 warns us against determining the impact of the CPS on interconnector flows without considering the impact of flows on the price differential. In this research, we estimate the impact of interconnector flows and the CPS on the IFA and BritNed price differentials, thereby obtaining the proportion of CPS that has been passed through to the GB day-ahead price. Using the regression results, we implement the following three-stage process. First, we estimate PDDSs without the CPS, holding flows at their original value. Second, we re-couple the interconnector markets, with any changes in flows further influencing the price differentials. Third, using the estimated price differentials and flows without the CPS but under market coupling, we evaluate the impact of the CPS on net imports, congestion income, the carbon cost pass-through to the cross-border market, and deadweight loss.[56] We estimate the impacts on both interconnectors to estimate the improvement in efficiency from aligning carbon pricing policy.

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

[56] Chyong et al. (2019) used the three-stage processes but in a different order: they first estimate the duration schedule curve without the interconnector and then estimate the impact of the CPS on the price differential. This

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

The second challenge is that the econometric model only allows us to estimate the partial effects of the CPS on price differentials conditional on the NTC and the partial effects of the NTC on price differentials conditional on the CPS. Therefore, using regression results to estimate the price differential after re-coupling the cross-border market (i.e. the second-stage of the three-stage process) could give invalid estimates. We deal with this by assuming that the impacts of interconnector flows on price differentials are independent of the CPS. In other words, we assume that with the CPS, a 1 GW flow would have an identical impact on the price differential as it would on the price differential without the CPS.[57]

4.4 Econometric models

In this section, we study the impact of interconnector flows and the British CPS on the day-ahead price differentials between the connected markets.[58] As electricity supply has to meet demand at every second, prices are highly volatile, and so are price differentials. To deal with this, we implement the Multivariate Generalised Auto-Regressive Conditional Heteroskedasticity (M-GARCH) model (Silvennoinen & Terasvirta, 2008), which accounts for variations in both the mean and volatility of electricity price differentials. The model

is justified under the assumption of a 100% CO2 pass-though, which is not conditional on the IFA transfer capacity.

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

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

has been widely used to model day-ahead electricity prices (e.g. Kirat & Ahamada, 2011; Anna-Phan & Roques, 2018).

Hourly prices for the next day are all set simultaneously in the day-ahead auction. Therefore, within a day the price for any hour does not carry much information about the next hour (Keppler, 2014; Würzburg *et al.*, 2013; Sensfuss *et al.*, 2008), hence neither does the day-ahead price differential. As a result, instead of treating the price differentials as an hourly univariate time series, we treat them as daily multivariate time series. In order to substantially reduce the number of parameters to be estimated, we assume that during peak hours (06:00-22:00 UTC) the electricity system exhibits similar scheduling behaviour and similarly during off-peak (22:00-06:00 UTC) hours.[59] For each interconnector, there are two time series (peak and off-peak) describing the price differentials. The models we estimate are bivariate GARCH models whose mean equation is

$$y_t = \mu + \sum_{i=1}^{m} \Phi_i y_{t-i} + \Gamma X_t + \varepsilon_t \tag{4.1}$$

and where

$$y_t = PD_t^{IC} = \begin{pmatrix} PD_t^{IC,PEAK} \\ PD_t^{IC,OFF} \end{pmatrix}$$

where IC refers to the interconnector, IFA or BritNed, and

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

for the other country OC∈ {FR,NL}, France or the Netherlands. PD_t represents DAM price differentials, i ∈ {PEAK,OFF}, t represents days, and P_t are day-ahead prices. X_t is a k × 1 vector of deterministic variables consisting of two types: period-specific covariates and shared covariates.

Within the day, period-specific covariates have different values in peak and off-peak periods, and include day-ahead forecasts of renewable generation, day-ahead forecasts of net generation (net of imports and renewables) and day-ahead forecasts of the net transfer capacity (NTC) of IFA and BritNed. We control for nuclear generation as it can influence the day-ahead price, especially for France (see Figure 4.3 for the impact of French nuclear outages). All period-specific covariates can be regarded as exogenous. Renewable generation depends on weather. Once the NTC has been controlled for, net demand is exogenous as it is inelastic in the short-run (Cló *et al.*, 2015), while day-ahead NTC depends on whether or not there are outages and is unaffected by prices. Nuclear generation runs unless there is an outage, although French nuclear power may reduce output off-peak, but separating each day into peak and off-peak periods controls that endogeneity.

[59] Figure 4.A1 in the Appendix presents the standardised average daily load curves for the three markets during the years of studying, and the two dashed vertical lines represent borders between peak and off-peak. The estimation results change little when the time band slightly varies.

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

The shared covariates have the same values for different periods of the same day, which includes variable costs for coal and gas plants (excluding carbon costs), the EUA price, the British CPS in Euro (using the daily exchange rate), and dummies for each season. Although some studies have found that dynamic interactions among fuel, carbon, and electricity prices may play an important role in price formation (Knittel and Roberts, 2005), we argue that fuel and carbon costs are more likely to be affected by the EU wholesale prices than by a single or pair of countries. The impact of fuels costs on the price differential would depend on the (marginal) fuel mixes in the two connected markets. Studies of IFA have shown that during 2013-2017, fossil fuel provided more than 80% of GB's marginal generation (Chyong *et al.*, 2019; Staffell, 2017), while the marginal generation in France has heavily relied on hydro and imports, these setting the price 89% of the time (Castagneto Gissey *et al.*, 2018). We might expect fuel costs and EUA prices to have a stronger impact on the GB DAM price than the French DAM price, while recognising that marginal imports come from other fossil-fuel intensive Continental markets (e.g. Germany, Italy, and Spain). These could significantly affect the French price, making the impact of fuel costs and EUA on the GB−FR price differential ambiguous. Similarly, while we expect the GB−NL price differential to be negatively correlated with the coal price and positively correlated with the gas price because the Netherlands is more coal-intensive than GB,[60] as NL is closely integrated with other Continental European countries, these impacts can also be ambiguous.

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

In Equation 4.1, $\Phi_1, \ldots, \Phi_m$ are 2 × 2 matrices of parameters capturing the spill-over effects across and within markets at period $t - i$, where $i = 1, \ldots, m$, and Γ is a 2 × k matrix with each element capturing the instantaneous impact of the corresponding covariates on the dependent variables. μ and ε_t are 2 × 1 vectors representing the constant terms and the error terms.

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

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

In order to control for heteroskedasticity and estimate the impact of the corresponding covariates on the volatility of price differentials, we assume ε_t to be conditionally heteroskedastic:

$$\varepsilon_t = H_t^{1/2}\eta_t \tag{4.2}$$

given the information set I_{t-1}, where the 2 × 2 matrix $H_t = [\sigma_{ij,t}^2]$, ∀i,j = 1, 2, is the conditional covariance matrix of ε_t . η_t is a normal, independent, and identical innovation vector with zero means and a covariance matrix equal to the identity matrix, i.e. $E\eta_t\eta_{tj}' = I$.

We use the Constant Conditional Correlation (CCC)[61] GARCH(1,1) model proposed by Bollerslev (1990), where the conditional correlation matrix, H_t, can be expressed as:

$$Ht = D_t^{1/2}RD_t^{1/2}, \tag{4.3}$$

where $R=[\varrho_{ij}]$ is a 2 × 2 time-invariant covariance matrix of the standardised residuals $D_t^{-1/2}\varepsilon_t$. R is positive definite with diagonal terms $\varrho_{ii}=1$. $D_t=[d_{ij,t}]$ is a diagonal matrix consisting of conditional variances with $d_{ii,t} = \sigma_{ii,t}^2$, and $d_{ij,t}=0$ for $i \neq j$.

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

$$\sigma_{ii,t}^2 = \exp(\gamma_i z_{i,t}) + \alpha\varepsilon_{i,t-1}^2 + \beta\sigma_{ii,t-1}^2 \tag{4.4}$$

$$\sigma_{ij,t}^2 = \rho_{ij}\sqrt{\sigma_{ii,t}^2\sigma_{jj,t}^2} \tag{4.5}$$

where $z_{i,t}$ is a k'×1 vector of deterministic variables.[62] In our case, $z_{i,t}$ contains a constant term as well as all deterministic variables in X_t in the mean equation (Equation 4.1). As domestic wind might increase the volatility of both domestic and cross-border DAM prices (Annan-Phan and Roques, 2018), its impact on the volatility of the price differential is unclear as wind is correlated across neighbouring countries. We would also expect the day-ahead NTC to lower price volatility as interconnectors facilitate convergence between the connected markets. Fuel prices have an ambiguous impact on the volatility of price differentials as it depends on the fuel mix, merit order and demand between the connected markets. Lastly, we expect the CPS to raise GB day-ahead price volatility as it pushes the less flexible coal

[61] The LM tests reject the null of varying conditional correlations.
[62] Exponential transformations were used to guarantee positive volatility.

generation from baseload to mid-merit (Chyong *et al*., 2019), thereby raising the volatility of the GB−FR (or GB−NL) price differentials.

In Equation 4.4, γ_i is a 1×k' vector of parameters capturing the instantaneous impacts of deterministic variables on the conditional variance, $\sigma_{ii,t}^2$, of $y_{i,t}$. In addition, α is the ARCH parameter capturing short-run persistence and β is the GARCH parameters capturing long-run persistence. One advantage for the M-GARCH model is that it allows for the existence of missing data, where the missing dynamic components are substituted by the unconditional expectations. The model is estimated by Maximum Likelihood Estimation (MLE). The number of lags m of the dependent variables will be determined by the Akaike Information Criterion (AIC) and the Bayesian Information Criterion (BIC).

4.4.1 Data

Day-ahead market (DAM) price data are collected from the ENTSO-E Transparency Platform, except for GB, which is collected from the Nord Pool Market Data Platform.[63] ENTSO-E also provides the day-ahead forecast of scheduled net generation (net of imports and renewables), renewable generation (wind and solar), and net transfer capacities (NTC). For nuclear generation, due to data availability we use the ex-post real data as proxies for the day-head forecast. As nuclear is highly inflexible, we would expect the forecast of nuclear generation to be reasonably close to actual generation.

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

Variable	Unit	Abbr.	Mean	S. D.	Min.	Max.
IFA Peak diff.	€/MWh	$PD^{\text{IFA,PEAK}}$	13.55	14.82	-70.63	240.05
IFA Off-peak diff.	€/MWh	$PD^{\text{IFA,OFF}}$	11.18	10.21	-38.48	48.36
BritNed Peak diff.	€/MWh	$PD^{\text{BN,PEAK}}$	15.24	10.90	-36.41	245.52
BritNed Off-peak diff.	€/MWh	$PD^{\text{BN,OFF}}$	12.51	5.38	-6.83	33.36
Peak GB renew.	GW	$R^{\text{GB,PEAK}}$	6.63	2.86	0.95	15.47
Off-peak GB renew.	GW	$R^{\text{GB,OFF}}$	4.85	2.83	0.37	13.87
Peak FR renew.	GW	$R^{\text{FR,PEAK}}$	3.90	1.62	0.90	11.99
Off-peak FR renew.	GW	$R^{\text{FR,OFF}}$	2.54	1.52	0.54	10.90
Peak NL renew.	GW	$R^{\text{NL,PEAK}}$	1.35	0.84	0.09	5.42
Off-peak NL renew.	GW	$R^{\text{NL,OFF}}$	1.03	0.75	0.04	4.19
Peak GB net gen.	GW	$G^{\text{GB,PEAK}}$	38.60	5.62	25.44	54.10
Off-peak GB net gen.	GW	$G^{\text{GB,OFF}}$	27.26	4.42	17.63	38.84
Peak FR net gen.	GW	$G^{\text{FR,PEAK}}$	64.11	10.01	42.99	89.61
Off-peak FR net gen.	GW	$G^{\text{FR,OFF}}$	57.20	9.27	37.84	81.91
Peak NL net gen.	GW	$G^{\text{NL,PEAK}}$	15.56	3.11	7.45	25.87
Off-peak NL net gen.	GW	$G^{\text{NL,OFF}}$	14.03	2.10	8.44	21.46
Peak GB nuclear	GW	$N^{\text{GB,PEAK}}$	7.37	0.69	4.31	8.99
Off-peak GB nuclear	GW	$N^{\text{GB,OFF}}$	7.38	0.68	5.18	8.98
Peak FR nuclear	GW	$N^{\text{FR,PEAK}}$	45.04	6.56	30.03	61.27
Off-peak FR nuclear	GW	$N^{\text{FR,OFF}}$	44.07	6.46	29.89	60.54
Peak NL nuclear	GW	$N^{\text{NL,PEAK}}$	0.45	0.20	0	0.55
Off-peak NL nuclear	GW	$N^{\text{NL,OFF}}$	0.45	0.20	0	0.55
IFA peak cap.	GW	$NTC^{\text{IFA,PEAK}}$	1.77	0.38	0.33	2.00
IFA off-peak cap.	GW	$NTC^{\text{IFA,OFF}}$	1.78	0.37	0.50	2.00
BritNed peak cap.	GW	$NTC^{\text{BN,PEAK}}$	1.00	0.13	0.00	1.06
BritNed off-peak cap.	GW	$NTC^{\text{BN,OFF}}$	1.01	0.10	0.00	1.04
Coal plant var. cost	€/MWh$_e$	VC^{COAL}	29.03	5.92	17.02	43.07
Gas plant var. cost	€/MWh$_e$	VC^{CCGT}	35.32	6.90	20.52	55.15
EUA price	€/tCO_2	EUA	8.835	4.85	3.99	25.25
CPS	€/tCO_2	CPS	21.32	2.82	12.17	25.95

Table 4.1. Summary Statistics, day-ahead markets.

The daily coal and gas prices as well as the EUA price are collected from the InterContinental Exchange.[64] The appropriate prices are the daily prices one day-ahead when offers are submitted. In order to calculate the delivered coal and gas costs into power stations, quarterly averages of the daily prices are subtracted from the BEIS quarterly "average prices of fuels purchased by the major UK power producers".[65] The daily data are then adjusted by adding this margin. All sterling prices are converted to Euros using daily exchange rates. We assume the thermal efficiency for coal-fired power plants to be 35.6% and 54.5% for CCGTs (Chyong *et al.*, 2019). This gives the variable fossil costs for coal and gas plants in €/MWh$_e$ without accounting for the carbon cost.

[64] theice.com

[65] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment data/file/790152/table 321.xlsx

The CPS increased from £9.55/t CO_2 to £18/t CO_2 on 1 April 2015. The lack of variation can potentially result in large standard errors for the estimated coefficients. We deal with this by converting the CPS from GBP to Euro, using the daily exchange rate, which is assumed a good forecast for tomorrow's rate. This also allows us to capture the impact on cross-border electricity trading of policy shocks such as the events of June 2016.

Table 4.1 gives summary statistics for all variables. Descriptive statistics of the DAM prices can be found in AppendixA.2. Outliers for price differentials are defined as values exceeding four standard deviations of the sample mean, and are removed and treated as missing data.

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

Table 4.2. ADF and Ljung-Box Tests on Price Differentials (in €/MWh), Lags=7.

Table 4.2 shows the Augmented Dickey-Fuller (ADF) and Ljung-Box test results. The ADF tests for the existence of a unit root (I(1) process) and the test statistics suggest that all price differentials have no unit root. The ADF test for DAM prices are provided in AppendixA.2, which also suggests no unit root for all prices, in agreement with other research (see e.g., Annan-Phan and Roque, 2018; Tashpulatov, 2013).[66] The Ljung-Box test uses the square of the demeaned dependent variables to test for the existence of heteroskedasticity (Harvey, 1993). The test results reject the null of homoskedastic variance and ensure the validity of controlling for heteroskedasticity.

4.5 Results

Both AIC and BIC suggest the order of the autoregressive process m in the conditional mean described by Equation 4.1 to be 7 for both interconnectors, equivalent to a weekly cycle, and helps to control for weekly periodicity. Likelihood Ratio (LR) tests determine whether the more complicated Dynamic Conditional Correlation (DCC) model instead of the proposed Constant Conditional Correlation (CCC) model is needed (Tse & Tsui, 2002). The test statistics for both regressions suggest using the CCC model. Estimates of the correlation coefficients, ϱ_{ij} in Equation 4.3 are within the interval of (−1, 1), and estimates of the conditional variance matrices, H_t , $\forall_t$ are positive definite, ensuring the validity of the M-GARCH model.

The next few subsections present the estimation results for key parameters for both IFA and BritNed. Section 4.5.1 presents the SR effect of deterministic variables on price differentials; Section 4.5.2 gives the estimated LR effects; Section 4.5.3 presents the impact on the volatility

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

of price differentials; Section 4.5.4 calculates, interprets and discusses the CPS pass-through to the GB DAM price. Sections 4.5.5 and 4.5.6 estimate the counterfactuals on both interconnectors without the CPS.

4.5.1 The short-run effects

Table 4.3 presents the main estimation results for the mean equation (Equation 4.1), which gives the instantaneous (SR) impacts of deterministic variables on the price differentials. As expected, because renewable generation lowers electricity prices, GB renewable generation (RGB) reduces the normally higher GB price and hence reduces the price differential. French and Dutch renewable generation (RFR and RNL) increase the price differential. The coefficients on renewable generation are all statistically significant. RFR and RNL have a higher impact on the price differential (in magnitude) than RGB. The reason might be that gas sets the price over 50% of the time in GB (Castagneto Gissey *et al.*, 2018; Chyong *et al.*, 2019), much more than its neighbours. This means that GB has a more flexible electricity system,[67] so GB prices are less affected by the variability of renewable generation.

On average, 1 GW in domestic wind generation instantly reduces the GB−FR (GB−NL) price differential $PD^{IFA,i}$ by €0.31 (0.27)/MWh during off-peak and by €0.41 (0.57)/MWh during peak periods, while 1 GW of Continental wind generation increases in $PD^{IFA,i}$ ($PD^{BN,i}$) by €1.80 (1.86)/MWh during off-peak and by €1.86 (2.15)/MWh during peak periods.

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

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

Table 4.3. Short-run Effects: M-GARCH Mean Equations.

Because GB typically imports from France and the Netherlands, additional IFA and BritNed NTC reduces price differentials for both interconnectors but creates more arbitrage revenue,

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

though their effects are only statistically significant during peak hours. This is not surprising if both markets have convex and monotonically increasing marginal cost curves, as illustrated in Figure 4.A2. During off-peak periods, electricity systems are running at base load with a relatively flat marginal cost curve, so a change in net demand has little impact on prices for either market. In general, IFA NTC has a much smaller impact on the price differential than BritNed's NTC because the French market is more than triple the size of the Dutch market (Table 4.1), so IFA capacity is a smaller proportion of French total load compared to BritNed's capacity share in the Netherlands. During peak periods, a 1 GW increase in the IFA NTC on average reduces $PD^{IFA,i}$ on that day by €1.26/MWh, while a 1 GW increase in the peak BritNed NTC on average reduces $PD^{BN,i}$ on that day by €3.34/MWh.

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

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

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

4.5.2 The long-run effect

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

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

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

Table 4.4. Long-run effects.

The estimates for the LR effects of EUA and CPS, and the corresponding standard errors are listed in Table 4.4.[68] As expected, the LR effects of EUA and CPS are both greater than the SR effects for both interconnectors both peak and off-peak. On (weighted) average, a €1/tCO_2 permanent increase in the CPS corresponds to a €0.49/MWh (s.e.=0.08) permanent increase in the GB−FR price differential, or a €0.40/MWh (s.e.=0.09) increase in the GB−NL price differential. Recall that conditional on NTC, these are also estimates of the permanent impact of CPS on the GB DAM price, and their difference is not statistically significant.

On one night in June 2016, the GBP/EUR exchange rate fell sharply from 1.30 to 1.17, or equivalently, reduced the GB CPS by €2.34/tCO_2. In the long run, those events reduced the GB−FR(NL) price differential by €1.42 (0.94)/MWh.

4.5.3 The impact on volatilities

Given the variability of wind, evidence has been found that wind generation increases the volatility of domestic prices (e.g. Wurzburg *et al.*, 2013; Jensen and Skytte, 2002, and Sensfuss *et al.*, 2008). The impact of wind generation on price differentials is less clear as wind across connected markets is strongly positively correlated in our data. The results in Table 4.5 suggest that off-peak renewable generation in both markets increases the volatility of price differentials while GB peak renewable generation (R^{GB}) reduces it. The positive effect is easy to explain because renewable generation (just wind as there is no off-peak solar generation) is unpredictable day-ahead. The negative effect during peak periods might be because high GB prices are less likely to occur during days with high renewable generation.[69]

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

[68] The LR effects on other deterministic variables can be obtained from the SR results in Tables 3 and A.4.
[69] Evidence can be found from the data, where when the peak GB price exceeds the sample mean by more than two standard deviations when GB renewable generation is only 70% of its sample mean.

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

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

Table 4.5. Volatility: M-GARCH Conditional Variance Equations.

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

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

The CPS increases the cost of generation and raises DAM prices. The ratio between the increase in the DAM price and the increase in the system marginal cost (due to the CPS, holding interconnector flows constant) is the CPS pass-through to the GB DAM price.

Using the estimated GB marginal emission factors (MEFs) from Chyong *et al*. (2019) we estimate that over 2015-2018[70] a €1/MWh increase in the CPS on average increases the system marginal cost of electricity by €0.374/MWh (s.e.= e0.005). Assuming the estimates of this paper and Chyong *et al*. (2019) are independent,[71] the SR CPS pass-through rate is 60% from IFA estimates (or 58% from BritNed estimates) with a 95% confidence interval of 35-85% (IFA) or 35-80% (BritNed).[72] In the short run, our estimates suggest that the market is not very sensitive to CPS changes due to exchange rate fluctuations.

[70] Chyong et al. (2019)'s period of estimation is 2012-2017 (see Appendix 4); here we assume the MEF for GB in 2018 is the same as that in 2017.
[71] These papers use different datasets.
[72] See http://www.stat.cmu.edu/~hseltman/files/ratio.pdffor computing the confidence intervals.

The estimated LR CPS pass-through rate from the IFA estimate is 163% (s.e.=31%) and from the BritNed estimate is 124% (s.e.=21%). These rates do not differ statistically significantly from each other nor from 100% (i.e. complete) pass-through (at the 1% significance level). This is consistent with a lagged adjustment to full pass-through and a workably competitive GB day-ahead market, although one could argue it provides some evidence of modest mark-up pricing and hence above 100% pass-through.

4.5.5 Trading over IFA without a carbon tax

During 2015–2018 the average peak (off-peak) IFA flow was 1,332 MW (1,206 MW) and the average peak (off-peak) NTC was 1,773 MW (1,783 MW). Given the estimated SR impacts of NTC on price differentials ($PD^{IFA,i}$) in Table 4.3, we estimate the average instantaneous impact of IFA flows on $PD^{IFA,i}$ as €−1.68/GW and €−0.29/GW for peak and off-peak, respectively.

The CPS coefficient in Table 4.3 shows the estimated instantaneous impact of the CPS on the price differential. Given this, we implement the three-stage processes set out in Section 4.3.2. We first estimate the counterfactual IFA price differential without the CPS, re-couple the market under the new price differential, and re-adjust the price differential if the interconnector flow has been changed. The actual price differential duration schedule (PDDS) curve of IFA from April 2015 to December 2018[73] as well as the estimated PDDS curve without the CPS are shown in Figure 4.A3.

Table 4.6 shows the average annual (electricity year from 1 April to 31 March) GB−FR price differential, GB annual net import, GB CPS tax revenue loss from trading, congestion income, inframarginal surplus, social surplus, the CPS pass-through to the cross-border market,[74] and the deadweight loss from the carbon cost distortion. The terms are defined in Section 4.3.1 as well as at the bottom of the table. The difference (wherever available) between the two CPS specifications are also listed (in the columns denoted with Δ).

As expected, the CPS has increased the GB−FR price differential, which further raised net imports into GB. The impact of CPS on the price differential varies across years as the exchange rate fell drastically after the events of June 2016. That has an additional impact on net imports with consequential impacts on the price differential. Perhaps unexpectedly, without the CPS GB's net imports during 2016-2018 would be close to zero, as the DAM price between the two country would also be close. This can be explained by French nuclear outages in both winters of 2016 and 2017 (see Figure 4.3), resulting in much higher DAM prices. During the three years, GB imported 30 TWh more electricity from France as a result of the CPS, with the loss of €252 million of carbon-tax revenue from the reduction in GB generation displaced, or €84 million/yr.

[73] Here the analysis starts from April 2015 (when the CPS moved to £18/tCO2.

[74] The pass-through rate in Section 4.5.4 is the CPS pass-through to the GB DAM price, while in this and the next subsection, pass-through refers to the increase in the GB DAM price (from CPS) passes through to the cross-border trading market, due to increases in electricity imports.

Electricity years	GB–FR Price Diff. (€/MWh)			GB Net Import (TWh)		
	£18 CPS	£0 CPS	Δ	£18 CPS	£0 CPS	Δ
2015-2016	€18.76	€7.38	€11.38	15.51 TWh	6.68 TWh	8.83 TWh
2016-2017	€8.56	– €1.14	€9.70	8.20 TWh	–1.12 TWh	9.32 TWh
2017-2018	€10.49	€1.95	€8.54	11.33 TWh	–0.56 TWh	11.89 TWh
Ave.	€12.60	€2.73	€9.87	11.68 TWh	1.66 TWh	10.02 TWh
	GB Tax Rev. Loss (m €)			**Congestion Income (m €)**		
	£18 CPS	£0 CPS	Δ	£18 CPS	£0 CPS	Δ
2015-2016	m €91.50	—	—	m €318	m €172	m €146
2016-2017	m €74.77	—	—	m €198	m €158	m €40
2017-2018	m €85.57	—	—	m €211	m €152	m €59
Ave.	m €83.95	—	—	m €242	m €161	m €81
	Infra-marginal Surplus (m €)			**Social Surplus (m €)**		
	£18 CPS	£0 CPS	Δ	£18 CPS	£0 CPS	Δ
2015-2016	m €18.36	m €15.99	m €2.37	m €336	m €198	m €148
2016-2017	m €12.52	m €12.19	m €0.33	m €211	m €170	m €41
2017-2018	m €16.81	m €15.98	m €0.83	m €228	m €168	m €60
Ave.	m €15.90	m €14.72	m €1.18	m €258	m €176	m €82
	CPS PT (€/MWh)			**Deadweight Loss (m €)**		
	£18 CPS	£0 CPS	Δ	£18 CPS	£0 CPS	Δ
2015-2016	– €1.90	—	—	m €17.41	—	—
2016-2017	– €2.03	—	—	m €17.79	—	—
2017-2018	– €2.62	—	—	m €25.80	—	—
Ave.	– €2.18	—	—	m €20.33	—	—

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

Table 4.6. Statistical Measurements for IFA: with and without the CPS.

The £18/tCO_2 CPS increased congestion income by €146 million between 2015 and 2016, by €40 million between 2016 and 2017, and by €59 million between 2017 and 2018, half of which goes to France.

While congestion income measures the private value of interconnectors, the social value would be higher as it also takes infra-marginal surplus into consideration. The estimated average infra-marginal surplus during the three years is €15.90 million with CPS or €14.72 million without, and the summation between congestion income and the infra-marginal surplus constitutes the social surplus of the interconnector.

As the CPS raised the GB DAM price and consequently, increased net imports, market re-coupling facilitates cross-border price convergence and partly offsets the initial impact of the CPS on the price differential. With the CPS but without the market re-coupling, the IFA price differential would have risen by €12.05 /MWh on average over 2015-2018. Re-coupling reduced that increase by €2.18 /MWh (or by 18%) on average over the three years.

Deadweight losses are incurred whenever interconnector flows change as a result of the CPS, as illustrated in Section 4.3.1. Assuming (locally) linear market supply curves for both

GB and France, the total deadweight loss is €61 million for the three years, or €20.3 million/yr.

4.5.6 Trading via BritNed without the CPS

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

- if both the unadjusted price differential (UDF) and adjusted price differential (APD)[75] are greater (or smaller) than zero, the NTC will be fully used for importing (or exporting);
- if the APD is zero and the UPD is positive, then the day-ahead commercial exchange would be randomly (uniformly) allocated within the interval between zero and the NTC;
- if the APD is zero and the UPD is negative, day-ahead flows would be randomly (uniformly) allocated as a negative number between minus NTC and zero;
- if the APD and UPD have different signs, we assume the direction of flows follows that in the previous hour, and the volume of the flow is randomly taken from the uniform distribution between zero and the NTC.

The PDDS curves for BritNed between April 2015 and December 2018 with and without the CPS are shown in Figure A4.[76] As with IFA, Table 4.7 shows the CPS increases GB −NL price differentials, net imports and congestion income. Without the CPS, congestion income from BritNed would fall by €62 million in 2015-2016, by €49 million in 2016-2017, and by €44 million in 2017-2018. This amount is equally shared by the Dutch and British TSOs. The impact of the CPS on BritNed's congestion income is more stable relative to IFA as the GB−NL price differential is less volatile (see Figure 4.3). In addition to the private value (i.e. the congestion income), the social value created by the BritNed is estimated to be around €10 million/yr higher.

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

[76] During 2015–2018 the average peak (off-peak) BritNed flow was 867 MW (798 MW) and the average peak (off-peak) NTC was 1,001 MW (1,006 MW). Given the estimated SR impacts of NTC on price differentials ($PD^{BN,i}$) in Table 4.3, we estimate the average instantaneous impact of BritNed flows on $PD^{BN,i}$ as €3.79/GW and €0.91/GW for peak and off-peak, respectively.

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

Table 4.7. Statistical Measurements for BritNed: with and without the CPS.

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

4.6 Conclusions and policy implications

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

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

congestion income, infra-marginal surplus, deadweight loss, and the amount of British carbon tax passed through to the cross-border market over both interconnectors.

Our estimates do not reject the null hypothesis that in the long run the CPS has been fully passed through to the GB day-ahead price. During electricity years 2015-2018, the CPS increased the GB DAM price by roughly €10.5/MWh in the absence of trade adjustments. The actual price differential with our neighbours (France and the Netherlands) fell to about €8.5/MWh allowing for displacement by cheaper imports. The CPS increased imports by 10 TWh/yr from France and by 3.6 TWh/yr from the Netherlands, thereby reducing carbon tax revenue by €84 million/yr from IFA and by €39 million/yr from BritNed. Congestion income for IFA was increased by €81 million/yr and for BritNed's by €52 million/yr, and the infra-marginal surplus from cross-border trading is around €15/million/yr for IFA AND €10 million/yr for BritNed. The summation of congestion income and infra-marginal surplus constitutes the social value of the interconnector. We estimated the deadweight loss due to the CPS was estimated to be €20.3 million/yr for IFA and €9.4 million/yr for BritNed. On average, about 18% of the increase in the GB day-ahead price from the CPS has been passed through in higher French prices and 29% in higher Dutch prices.

The results confirm that the British CPS raised the GB spot price, reduced the convergence of cross-border electricity prices and increased GB imports of electricity. Second, the increase in congestion income (mostly) comes from GB electricity consumers but is equally allocated to both Transmission System Operators as owners of the interconnectors. This increased congestion income might over-incentivise further investment in additional interconnectors, at least to carbon-intensive markets lacking such carbon taxes. Third, as a non-negligible proportion of the GB DAM price increase caused by the CPS was passed over the interconnectors, both French and Dutch day-ahead prices have been slightly increased. That raised their producer surplus but increased consumer electricity costs. Fourth, the objective of the British CPS is to reduce British CO_2 emissions and incentivise low-carbon investment, but this may be partly subverted by increased imports of more carbon-intensive electricity. However, the ETS Market Stability Reserve should reduce aggregate EU emissions by a substantial fraction of the GB reduction. Note the same argument could previously be made that reductions in GB emissions are offset by increased emissions elsewhere, but this has been largely addressed by the Market Stability Reserve. Finally, asymmetric carbon pricing in two connected countries incur deadweight losses, resulting in less efficient cross-border trading.

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

5 Measuring inefficiency in international electricity trading

Interconnectors reduce the cost of electricity supply if they are operated efficiently. We show that established metrics used to monitor electricity trading inefficiency become increasingly inaccurate in several trading conditions. We devise the Unweighted and Price-Weighted Inefficient Interconnector Utilisation indices to address these deficiencies. These metrics are substantially more accurate than existing ones and perform equally well whether or not markets are coupled. Our results show a substantial decrease in inefficient trading between Great Britain and both France and the Netherlands after the European Union's market coupling regulations were introduced in 2014.

In view of Great Britain's planned withdrawal from the European Union, the paper also evaluates how market uncoupling would affect cross-border trade. We find that uncoupling would lead to inefficiencies in trade, the electricity price differential between GB and France (Netherlands) rising by 2% (0.6%), net imports into GB decreasing by 22% (6%), congestion income decreasing by 6% (1.5%), and infra-marginal surplus decreasing by 25% (9). We also show that, should the EU decide to implement an equivalent carbon tax to GB's Carbon Price Floor, uncoupling impacts would be magnified due to electricity prices.

5.1 Introduction

Interconnectors link national electricity systems and enable countries to trade electricity between markets (e.g. between Great Britain and the island of Ireland), or to create single electricity markets (e.g. on the island of Ireland). Electricity systems have periods of high and low demand, and variable renewable generation creates periods of high and low available supply. Since supply–demand imbalances differ across countries, interconnectors can reduce these imbalances by moving electricity over space (in contrast to storage, which moves energy over time) (Newbery *et al.*, 2018). Europe plans to substantially increase interconnection capacity. For example, GB has 5 GW capacity to four countries, and the UK regulator, Ofgem, has approved projects to increase capacity to 16 GW by 2030 (Castagneto Gissey *et al.*, 2019).

From an economic perspective, interconnectors create value by enabling electricity imports from markets with lower prices, as an alternative to higher-priced indigenous generation. This reduces the overall cost of supplying electricity across the two systems, and would be expected to reduce consumer prices and increase consumer welfare in the importing country. However, these benefits of interconnectors will only be realised if electricity flows in the economic direction, and this will not happen unless markets are efficiently integrated. Several metrics have been developed to measure and hence monitor *trading inefficiency* (e.g. in ACER, 2012). In this paper, we critically examine these metrics, and propose a series of improved metrics for future use.

5.1.1 Electricity trading via interconnectors

Electricity generation for each period (typically an hour) is generally traded in forward, day-ahead, intraday, and balancing markets. Forward market trades can take place months

ahead of delivery. Day-ahead capacity is nominated and scheduled at around midday on the day prior to delivery. Traders subsequently have an opportunity to buy and nominate capacity in the intra-day market typically until a few hours before flow. Interconnected trading occurs in these electricity markets, but the approach is very different depending on whether the two connected markets are *uncoupled or coupled*.

Historically, national markets were *uncoupled*, which meant interconnector capacity scheduling and purchasing/selling electricity in each market took place separately. The interconnector flow would be planned on the basis of predicted prices, and many of these flows were ultimately in the 'wrong' direction for periods where the price differential subsequently reversed. Electricity flows from higher to lower priced regions are termed Flows Against the Price Differential (FAPDs) (ACER, 2012) and are usually[77] caused by the markets for interconnector capacity and delivery of energy closing at diferent times.

The Integrated Electricity Market (IEM) came into force in the EU in 2014 to allow electricity to be traded freely between member states through *coupled* markets, with the aim of reducing trading inefficiency (ACER, 2015). All bids and offers are submitted to the day-ahead market at the same time. A shared algorithm known as EUPHEMIA (ACER, 2017) matches supply and demand and schedules all interconnector flows from low- to high-price regions, until either the price differential is eliminated or the interconnector reaches full capacity with each region then having a different market clearing price. In 2019, 23 European countries had coupled markets.[78] Intra-day coupling became available in 2018 for some European markets, while coupling balancing markets in 2019 was still at an early stage (ACER, 2017).

5.1.2 Previous studies of trading inefficiency

The welfare gains[79] from international electricity trading depend on the price differential between the markets as well as the trading inefficiency (Ochoa and van Ackere, 2015). Several studies estimate trading efficiency. Some have relied upon historic interconnector performance (e.g. ACER, 2012; EU Commission, 2010-Q3). Pariso and Pelagatti (2019) have taken such an approach to evaluate the Italian-Slovenian interconnector. Other studies have used electricity system models (e.g. Pöyry, 2012; Redpoint, 2013; EU Commission, 2015; and Aurora, 2016). Zakeri *et al.* (2018) model the likely efficiency and welfare gains of proposed interconnection between the UK and the Nordic power markets.

Newbery *et al.* (2013) reviewed the literature on the quantitative benefits of market integration, finding substantial monetary advantages (€1 bn/yr from just coupling, twice that if balancing is integrated) from EU market coupling, albeit a modest percentage of total sales value of electricity. Pollitt (2018) concludes that measurable benefits of the Integrated

[77] Ramping constraints may limit the rate at which the direction and/or volume of flow can respond to price changes.
[78] Nineteen via Multi Regional Coupling (MRC) and four via 4M Market Coupling (4MMC) covering the Czech-Slovak-Hungarian-Romanian market areas.
[79] Information about estimating welfare gains is given in Appendix 5.1.

Electricity Market are likely to be small relative to total trade, in part because there has been a large rise in subsidised renewable generation that has not been efficiently allocated across member states.

ACER (2017) compared the success of intraday market coupling for a selection of regions and concluded that markets using implicit allocation (as with market coupling) are 40% inefficient while those using explicit allocation (in which capacity is procured separately from energy) are 53% inefficient. However, they focus exclusively on flows that have 'a value' (i.e. those flowing in the correct economic direction) and so ignore inefficient flows. The low inefficiencies reported are a reflection of the still incomplete integration of EU intraday markets.

Following Brexit, it is possible that the UK will no longer have access to the EUPHEMIA platform and will need to return to uncoupled trading with neighbouring markets. Geske *et al.* (2019) develop a model of market frictions based on FAPDs to estimate the impact of higher trading inefficiency and less investment in future interconnection at €700m each year by 2030.

5.1.3 Contribution and structure of this paper

Previous metrics of trading inefficiency have two important limitations. First, several do not consider the magnitude of flows with and against price differentials, so the relative importance of any FAPDs cannot be measured. Second, they do not consider the magnitude of the price differential for FAPDs, which is important because larger price differentials cause greater economic losses. This paper systematically evaluates existing metrics of day-ahead trading inefficiency for the first time. Based on this analysis, we propose two new measures of trading inefficiency that address these limitations. We evaluate these against existing metrics using a series of trading patterns, and historical trading data for both coupled and uncoupled markets.

We use the insights from our new metrics with an econometric model to explore the potential economic losses caused by the GB electricity market becoming uncoupled from France and the Netherlands. We investigate the impacts on net electricity imports, price differentials, trading inefficiency, and the private and social value of the existing interconnectors. The insights can be used to design policies that minimise welfare losses.

The paper is structured as follows. In Section 5.5.2, existing measures of trading inefficiency are described, and our two new measures are defined. We evaluate our novel metrics against existing metrics in Section 5.5.3. In Section 5.5.4, we analyse the economic impact of market uncoupling. We conclude by considering the policy implications in Section 5.5.5. More detailed information about trading inefficiency metrics and our methods are available in Appendices 5.1–5.8.

5.2 Measures of trading inefficiency

We focus on trading inefficiency in the day-ahead market. Metrics of cross-zonal capacity utilisation inefficiency determine how inefficiently interconnector transmission capacity is used: the percentage of capacity not allocated in the correct direction (from lower to higher priced zones).

Analyses of day-ahead and intra-day trading inefficiency involve several approaches and varying degrees of complexity. We categorise metrics of trading inefficiency as: (i) price-based; (ii) flow-based; and, (iii) price- and flow-based metrics. Studies using these measures are listed in Table 5.1.

Method	Data	Report/Author	Metric description/method
Historical analysis	*Price*	ACER (2011)	Percentage of hours when hourly day-ahead (DA) prices were equal.
		ACER (2012)	Categorised (low, medium, high) DA price convergence.
		EU Commission (2012-Q3)	Weekly ratio of price convergence.
		EU Commission (2012-Q2)	Percentage of hours with price convergence below 1%.
	Flow	ACER (2012)	Indexed annual aggregation of hourly NTC values.
		ACER (2012)	Capacity utilisation ratio.
		ACER (2017)	Absolute sum of net nominations.
	Price and flow	Montoya *et al.* (2019)	Unweighted Inefficient Interconnector Utilisation (UIIU) – Eq.4*
		Montoya *et al.* (2019)	Price-Weighted Inefficient Interconnector Utilisation (PWIIU) – Eq.5*
		ACER (2012)	Percentage of hours with day-ahead nominations against price differentials.
		ACER (2018)	Percentage of the available NTC used in the correct economic direction.
		ACER (2012)	Loss in Social welfare.
		EU Commission (2010-Q3)	Unweighted Flows Against Price Differential (UFAPD, or FAPD).
		EU Commission (2010-Q3)	Split of flows against price difference by subcategory of pre-established intervals of price differentials.
		EU Commission (2010-Q3)	Monetary value of energy exchanged in inefficient flow regime.
		EU Commission (2010-Q3)	Sum of hourly values of absolute price differentials multiplied by net cross border flows.
		Newbery *et al.* (2019)	Value Destruction.
		Newbery *et al.* (2019)	Percentage of potential congestion revenue.
		Meeus (2011)	Test on unused capacity times price differential.
Simulation-based analysis		ACER (2011)	Measures of social welfare.
		De Jong *et al.* (2007)	
		Newbery *et al.* (2016)	

Table 5.1. Classification of measurements used for measuring market coupling. The shaded area denotes measures of cross-zonal capacity utilisation inefficiency. * indicates the present study.

Price-based metrics mainly include mean or median price differentials and econometric methods to assess prices, including correlation and co-integration analyses (Castagneto Gissey *et al.*, 2014; ACER, 2015, 2017). Flow-based metrics include: Indexed annual aggregation of hourly NTC values; Capacity utilisation ratio; and Absolute sum of net nominations per year (ACER, 2012; 2018). A full description of price-based and flow-based metrics is provided in Appendix 5.2.

5.2.1 Price-and-flow-based metrics

We focus on price-and-flow-based metrics as the most informative and widely used for policy purposes.

5.2.1.1 Flows Against the Price Differential (*FAPD*)

FAPD measures the fraction of times electricity flows from higher to lower priced zones (EU Commission, 2010). In any time period, the *FAPD*, is the total number of inefficient imports (and exports) N^- divided by the total number of flows N:

$$FAPD = UFAPD = I_1 = \frac{N^-}{N} \tag{5.1}$$

Similarly, for Flows With the Price Differential (FWPD) *UFWPD* is calculated as N^+/N.

Since the magnitude of the price differential is not reflected in the *FAPD*, we refer to this as the Unweighted FAPD or *UFAPD* in this paper. *UFAPD* values between 2% and 6% have been found by Newbery *et al.* (2016), representing the imperfect coupling in European day-ahead markets over interconnectors between Germany, Denmark, Spain and France before 2014.

The simplicity of *UFAPD* is attractive but it ignores the quantity of electricity traded unprofitably and the price differentials at which these trades occurred. For example, 53% of potentially valuable trade was exchanged between Belgium–Netherlands during FAPDs, despite these comprising only 0.01% of all flows (Figure 1). Hence judging the inefficiency of an interconnector utilisation based solely on *UFAPD* could be highly misleading.

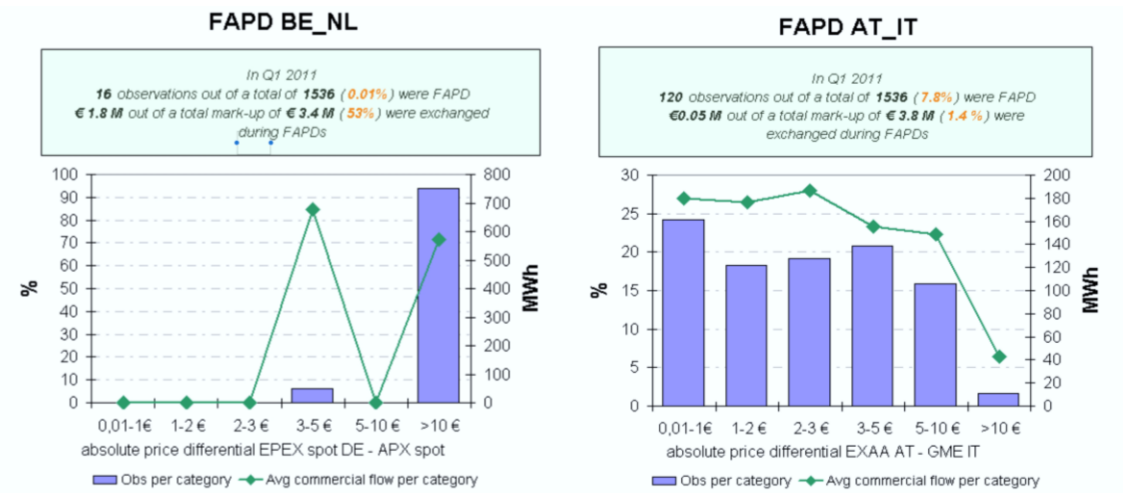

Figure 5.1. Chart of inefficient flows for the Belgian-Dutch and Austrian-Italian markets. Numbers in brackets indicate Unweighted FAPD (FAPD) and Weighted FAPD (WFAPD). Source: European Commission (2011-Q1).

Figure 5.2 shows the combinations of net scheduled imports and transmission loss-adjusted price differentials relating to trades over the GB–France IFA interconnector before and after market coupling in 2014. This 'S-curve' presents the raw *scheduled* commercial exchanges, so does not account for the possibility of unplanned outages. In 2017, there are horizontal

bands of observations at multiples of 500 MW because of periodic partial de-rating of one or more cables (IFA has four 500-MW cables). Note the absence of costly imports and low-priced exports in the coupled graph, where electricity flowed in the efficient economic direction. In this case, the S-curve suggests *UFAPDs are* close to zero.

The pre-2014 situation is quite different and clearly shows strong deviations from the perfect trading described earlier. There are persistent price differentials even with no capacity restrictions, which suggests that trading was not fully efficient, with numerous periods with electricity flowing in the wrong direction. Possible reasons for inefficient use were investigated by various authors (Bunn and Zachmann, 2010; Ehrenmann and Smeers, 2005; Geske *et al.*, 2019), and include: (i) uncertainty arising from separate energy and transmission markets; system operators being required to schedule cross-border flows for congestion and system balancing; and, (ii) strategic trading by generators with market power. The S-curve is dispersed, indicating inefficient trading.

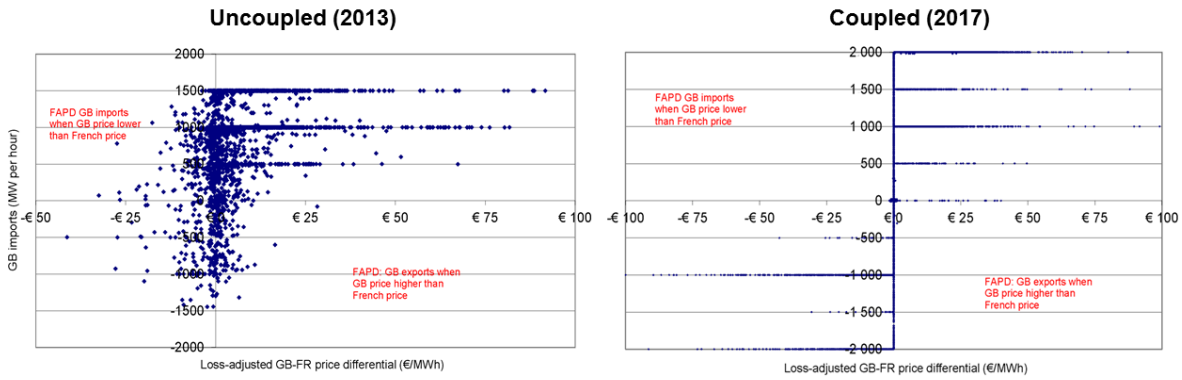

Figure 5.2. GB scheduled net imports vs price differentials on the IFA interconnector between GB and France before and after the 2014 implementation of the EUPHEMIA market coupling algorithm. For additional related graphs see also Appendix 5.3.

5.2.1.2 Weighted FAPD (*WFAPD*)

The Weighted FAPD, *WFAPD*, (EU Commission, 2010) accounts for the monetary value of the uneconomic flows and is defined as:

$$WFAPD = I_2 = \frac{\sum_h^{N^-} |\tilde{f}_h^- * x_h^-|}{\sum_h^{N^-} |\tilde{f}_h^- * x_h^-| + \sum_h^{N^+} |\tilde{f}_h^+ * x_h^+|}, \tag{5.2}$$

where – and + denote 'wrong' (inefficient) and 'correct' (efficient) direction; $\tilde{f}$ are flows during hour h at a corresponding price differential of x, and $|\tilde{f} * x|$ is the absolute value of $\tilde{f} * x$. The EU Commission (2010) denotes "welfare loss" and "mark-up" as the numerator and denominator respectively. Figure 5.1 shows the inefficient flows for the Belgian-Dutch and Austrian-Italian markets, with the numbers in brackets indicating (in order) the Unweighted FAPD and Weighted FAPD, illustrating the differences between the metrics.

The 53% value calculated using the *WFAPD* metric improves on the UFAPD. Yet it still does not completely describe interconnector inefficiency because it does not take account of the Net Transfer Capacity (NTC) that is actually available. During periods without inefficient

flows, both measures indicate zero inefficiency, even if the interconnector capacity is underused.

5.2.1.3 Share of capacity used in the correct economic direction (*SCURED*)

Another measure of market coupling derives the share of capacity used in the correct economic direction and is illustrated in Figure 5.3. We reproduce this metric from ACER (2018) as:

$$SCURED = I_3 = \frac{\sum_h^{N^+} \sum_i^B M_{i,x(h)>k}^+}{\sum_h^{N^+} \sum_i^B NTC_{i,x(h)>k}^+} \tag{5.3}$$

Here N^+ represents the number of hourly (h) nominations (M) that occurred across a given border (B) in the efficient economic direction (+) with the available Net Transfer Capacity (NTC); k denotes a threshold (normally set to €1/MWh) to represent the level below which price differential (x) observations are excluded from the calculation. ACER (2018) uses this to derive the share of capacity used in the efficient direction relative to the price differential.

The advantage of *SCURED* is that it indicates how much of the capacity is used to flow electricity associated with a favourable price differential, but like *UFAPD* it lacks information about the price differential at which these flows occurred.[80] Another shortcoming is that the presence of flows against the price differential does not impact the metric at all and, as such, its accuracy diminishes as the number of inefficient flows increases.

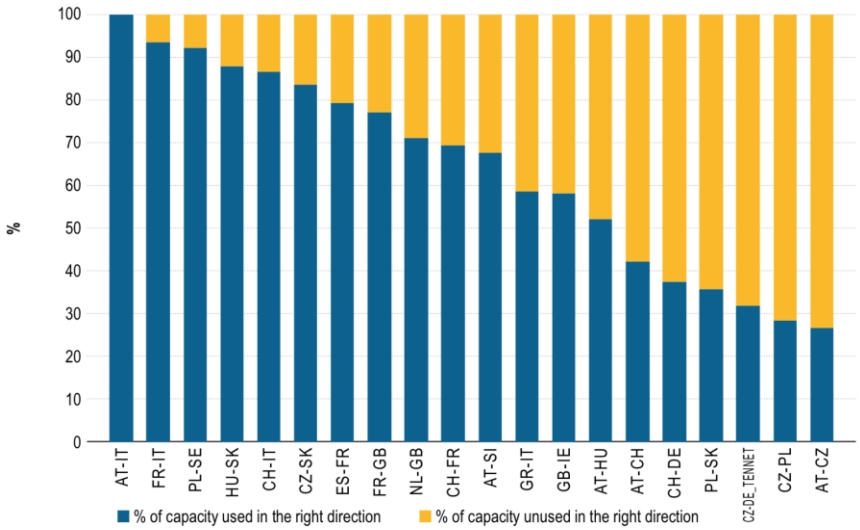

Figure 5.3. Percentage of NTC used in the correct economic direction for a selection of EU borders in 2011. Note that this was prior to coupling through EUPHEMIA. Source: ACER (2012).

[80] Apart from these having occurred above the predetermined significant price differential threshold.

5.2.1.4 Inefficiency based on nominal capacity

If prices are materially different, interconnector capacity should be fully used, while it should be underused only if prices are essentially the same. This metric indicates the percentage of potential congestion revenue. For example, the BritNed interconnector has a capacity of 1,000 MW. From 2015–18 this measure of efficiency is 95% (€12,276/hr vs €13,378/hr), yielding €107m/yr (Newbery *et al.*, 2019), assuming the interconnector is available at full capacity throughout each year. This is equivalent to 5% inefficiency. Its main advantage is that it is simple to estimate given the day-ahead market prices in each country and the nominal capacity of the interconnector, but its drawback is that full capacity may not be available for technical or other reasons, and so overstates what could actually be earned.

5.2.1.5 Value destruction

Value destruction is calculated as the physical flow times the price differential for flows against the price differential (FAPDs), indicating the loss that could have been avoided by not flowing. Newbery *et al.* (2019) compute value destruction on the IFA interconnector before the 2014 coupling of GB and France. Value destruction in 2013 was 14% of the total value of €231m/yr at €31.9m/yr.

Several studies have calculated social welfare based on models of the underlying electricity system. With numerous assumptions varying across models and studies, this makes comparisons with analyses using historic traded data difficult. More information about measures of social welfare is given in Appendix 5.1.

5.2.2 Defining an ideal metric for interconnector trading inefficiency

The ideal metric should provide the highest degree of accuracy irrespectively of whether two markets are coupled or not. To ensure transparency, it should use information that is readily available to the public and not rely on proprietary data, which would restrict use. The underlying algorithm should ideally be simple to implement with commonly used software. These properties ensure reproducibility and auditability.

As interconnectors have different capacities, the metric should facilitate comparisons of trade inefficiency, so absolute valued metrics (whether in currency or energy units) would make this difficult. An index ranging, for example, between 0% and 100% is easier to interpret.

5.2.3 Interconnector utilisation inefficiency metrics

We have developed two new metrics that uniquely include information not only on the direction of flows (both efficient and inefficient) and the price differential, but also on the

percentage of net transfer capacity used during the cross-zonal exchange. Our new metrics similarly have values ranging from zero to unity.[81]

Considering a sample size N of hourly *price differential* and *flow* combinations, we define the *Unweighted Inefficient Interconnector Utilisation*[82] (UIIU) metric as:

$$UIIU = I_4 = \left(\frac{N^-}{N}\right)\left(\frac{1}{N^-}\right)\sum_h^{N^-}\frac{(1+|f_h^-|)}{2} + \left(\frac{N^+}{N}\right)\left(\frac{1}{N^+}\right)\sum_h^{N^+}\frac{(1-|f_h^+|)}{2} + \left(\frac{N^0}{N}\right)\left(\frac{1}{N^0}\right)\sum_h^{N^0}\frac{(1-|f_h^0|)}{2} \tag{5.4}$$

where

$$\begin{aligned} N &= N^- + N^+ + N^0 \\ F &= f^- + f^+ + f^0 \\ |f| &= absolute\ value\ of\ f \\ f_h &= \frac{\tilde{f}_h}{NTC_h},\ f_h^0 = 0, \end{aligned}$$

with the superscripts '-', '+', and *'0'*, denoting inefficient-*flow (i.e. a FAPD)*, efficient-*flow* and *no-flow,*[83] respectively. *NTC* stands for Net Transfer Capacity, while $\tilde{f}_h$ is the hourly flow. *UIIU* is an index of trading *inefficiency* ranging from 0 to 1, with a value of 0 indicating no inefficiency (or 100% efficiency), and a value of 1 indicating maximum inefficiency (0% efficiency). The level of *efficiency* is 1 – I_4.

Consider two inefficient flows of 900 MW with the first occurring at a price differential of €200/MWh and the second at a €2/MWh price differential. Everything else being equal, the first inefficient flow is more costly and hence more inefficient than the second. As the flows in Equation 5.4 already adjust for NTC, it remains to adjust for the price differential (analogous to *WFAPD* adjusting *UFAPD*) leading to the *Price-Weighted Inefficient Interconnector Utilisation* (PWIIU) metric.

$$PWIIU = I_5 = \sum_h^{N^-} w_h \frac{(1+|f_h^-|)}{2} + \sum_h^{N^+} w_h \frac{(1-|f_h^+|)}{2} + \sum_h^{N^0} \frac{w_h}{2} \tag{5.5}$$

where

$$w_h = \frac{|x_h|}{\sum|x_h|},$$

[81] A case could be made for a metric ranging from -100% to +100%, where -100% implies that all the potential gains are not just foregone but reversed, destroying value. However, it is conventional to state that zero efficiency is full or 100% inefficiency and we follow this convention, hence the halving in equations (5.4) and (5.5).

[82] A detailed derivation can be found in Appendix 5.4. A simplistic interpretation of Equation (1) is the average flow-distance from the S-curve weighted by the proportion of FAPDs (or FWPDs) observed in the corresponding (efficient or inefficient) region.

[83] A no-flow is the event of zero IC utilisation given that a non-zero price differential occurred.

and x is the price differential. *PWIIU* also ranges between 0 and 1 with values interpreted in the same way as for *UIIU*.

Equation 4 is deliberately specified to blend existing metrics (*UFPAD* and *SCURED*) and can be rewritten as:

$$UIIU = (UFAPD)\left(\frac{1}{2N^{-}}\right)\sum_{h}^{N^{-}}(1+|f_h^{-}|) + \left(\frac{1}{2N}\right)\sum_{h}^{N^{+}}(1-SCURED_h) + \left(\frac{N^0}{2N}\right) \tag{5.6}$$

A Microsoft Excel formula is provided as an attachment to this paper to facilitate estimation. See Appendix 5.5.

5.3 Evaluating the metrics

We benchmark our metrics against *UFAPD*, *WFAPD*, and *SCUWED* =1 - *SCURED*,[84] as these are regularly used in official market reports (e.g. ACER, 2016; 2017; and EU Commission, 2015-Q1). First, we use a series of hypothetical trading scenarios, which represent extreme cases of interconnector utilisation, to test the robustness of the metrics. Second, we assess variations between metrics using historical data for the IFA interconnector between Great Britain and France and for the BritNed interconnector between Great Britain and The Netherlands for the years 2013 to 2018.

5.3.1 Stress-testing the metrics using a series of market scenarios

We construct a total of eleven scenarios that represent a range of conditions in coupled and uncoupled markets, with the aim of stress-testing the metrics (assuming a constant NTC of 2,000 MW, full capacity on IFA):

- *Scenarios 1 to 4* span the combination of high price differentials (for both profitable and unprofitable flows) with varying interconnector efficiency utilisations.
- *Scenarios 5 and 6* represent periods of zero and 100% unprofitable flows.
- *Scenarios 7 and 8* represent a very low number of extreme price differentials in instances of profitable and unprofitable flows.
- *Scenario 9* contains only a single profitable flow at a low price differential that is captured at 90% of available NTC.
- *Scenarios 10 and 11* contain 100% profitable flows and differ in the degree to which the large price differentials are captured with interconnector use.

These scenarios are described in Table 2 and illustrated in Figures 5.4 to 5.7. Table 5.3 contains the metrics for each scenario.

[84] As *SCURED* is an efficiency measure, we define *SCUWED* = 1 - *SCURED* as the inefficiency measure.

Scenario	Metric outcome	Explanation
1	Medium inefficiency: between 25% and 75%	Efficient flows account for 94% of all flows but are utilised at low levels of available capacity. Inefficient flows occurring at high price differentials flow at high levels of available capacity.
2	Low inefficiency: < 25%	Efficient flows account for 94% of all flows and are utilised at high levels of available capacity. Inefficient flows occurring at high price differentials flow at low levels of available capacity.
3	Medium inefficiency: between 25% and 75%	Efficient flows account for 94% of all flows but are utilised at low levels of available capacity. Inefficient flows occurring at low price differentials flow at high levels of available capacity.
4	Low inefficiency: < 25%	Efficient flows account for 94% of all flows and are utilised at high levels of available capacity. Inefficient flows occurring at low price differentials flow at low levels of available capacity.
5	Low inefficiency: < 25%	Efficient flows account for 100% of all flows and are utilised at high levels of available capacity.
6	High inefficiency: > 75%	Efficient flows account for 0% of all flows (all flows are inefficient) and are utilised at high levels of available capacity.
7	Medium inefficiency: between 25% and 75%	Efficient flows account for 98% of all flows and are utilised at low levels of available capacity.
8	Medium inefficiency: between 25% and 75%	Efficient flows account for only 2% of all flows. However, they occur at very high levels of price differentials and use more of the available capacity than the FAPDs.
9	Very high inefficiency: > 95%	Efficient flows account for 0.01% of all flows (only one such observation): FAPDs are captured at high levels of available capacity.
10	Low inefficiency: < 25%	Efficient flows account for 100% of all flows: larger proportion of flows occurred at 50% of available capacity than at 100% of available capacity
11	Low inefficiency: < 25%	Efficient flows account for 100% of all flows: larger proportion of flows occurred at 50% of available capacity than at 100% of available capacity

Table 5.2. Scenarios and metric outcome description.

Scenario	N+	N-	UFAPD	WFAPD	SCUWED	UIIU	PWIIU
1	699	45	6%	85%	86%	46%	66%
2	699	45	6%	17%	5%	6%	32%
3	699	45	6%	17%	76%	41%	41%
4	699	45	6%	1%	5%	6%	5%
5	744	0	0%	0%	5%	2%	2%
6	0	744	100%	100%	UND	98%	98%
7	729	15	2%	70%	86%	44%	56%
8	15	729	98%	30%	32%	56%	44%
9	1	743	100%	100%	10%	97%	98%
10	168	0	0%	0%	34%	17%	18%
11	168	0	0%	0%	34%	17%	17%

Table 5.3. Results using stress data for each of the metrics based on price differentials and flows. UND=Undefined. N^+, N^-, and N^0 indicate flows in the correct direction, in the wrong direction, and no flows, respectively.

5.3.1.1 Scenarios 1–4 (Low number of inefficient flows)

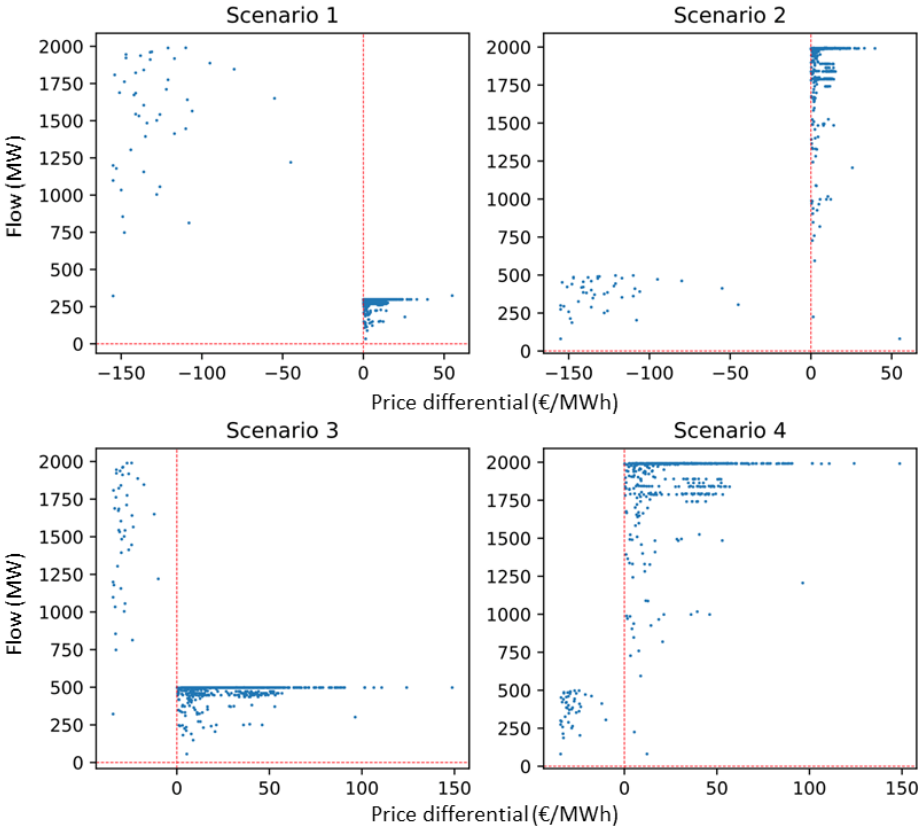

Figure 5.4. Scenarios 1–4: Low number of inefficient flows.

These scenarios represent a range of low inefficient flow proportions combined with varying degrees of price differentials and NTC utilisation. As an absolute measure of inefficiency, Table 5.3 demonstrates the inability of the *UFAPD* index to address an interconnector's underutilisation of efficient flows in Scenario1. Likewise in Scenario 3, *WFAPD* underestimates the inefficiency as it fails to capture the underutilisation of NTC by beneficial flows. Both *WFAPD* and *PWIIU* correctly capture the subtlety in Scenario 2 where, despite the rare appearances, inefficient flows occurred at very high price differentials.

5.3.1.2 Scenarios 5–6 (0% and 100% inefficient flows)

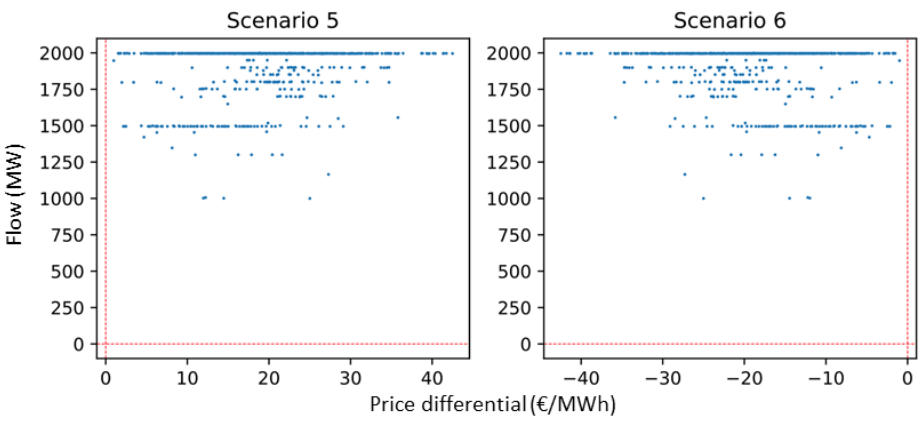

Figure 5.5. Scenarios 5–6: 0% and 100% inefficient flows.

UFAPD and *WFAPD* results are binary: they indicate either 0% or 100% inefficiency. *SCUWED*, *UIIU* and *PWIIU* provide greater accuracy as they are relative to NTC. *SCUWED* is undefined for Scenario 6 as that metric solely focuses on FWPDs. *WFAPD* understates inefficiency in Scenario 5 as by design it is not rescaled by NTC. Scenarios 5 and 6 are mirror images of one another and *UFAPD*, *UIIU* and *PWIIU* reflect this as their results add up to 1 over both those scenarios.

5.3.1.3 Scenarios 7–8 (Low NTC utilisation)

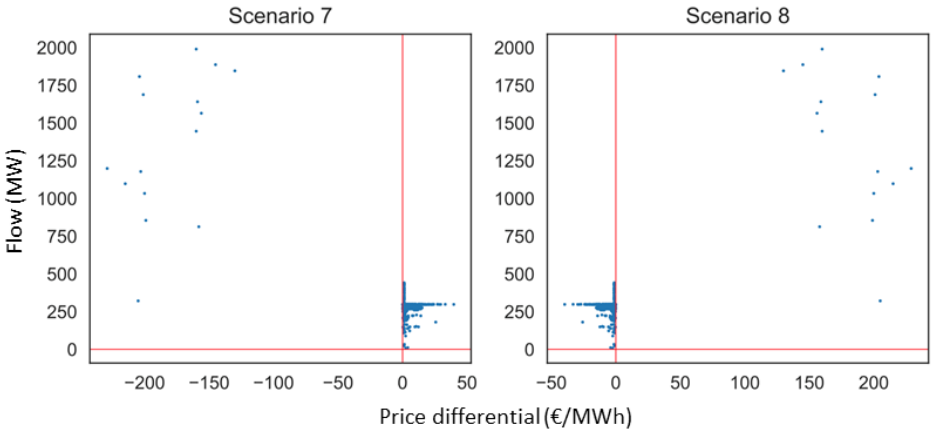

Figure 5.6. Scenarios 7–8: Low NTC utilisation.

Scenario 7 is inspired by Figure 1 but at varying levels of NTC utilisation by the FAPDs. The very high number of efficient flows in that scenario underutilise NTC and as such their efficiency is negated by the low number of FAPDs. Scenario 8 is a mirror image of Scenario 7. *UFAPD* provides an unrealistically low inefficiency in Scenario 7 since it only focuses on the low number of inefficient flows. The change in *WFAPD*'s 'welfare loss' over the two scenarios is what drives the large decrease in its value. *PWIIU* reacts in a similar fashion to *WFAPD* due to its weighting scheme.

5.3.1.4 Scenarios 9–11 (1 inefficient flow and 0% inefficient flows)

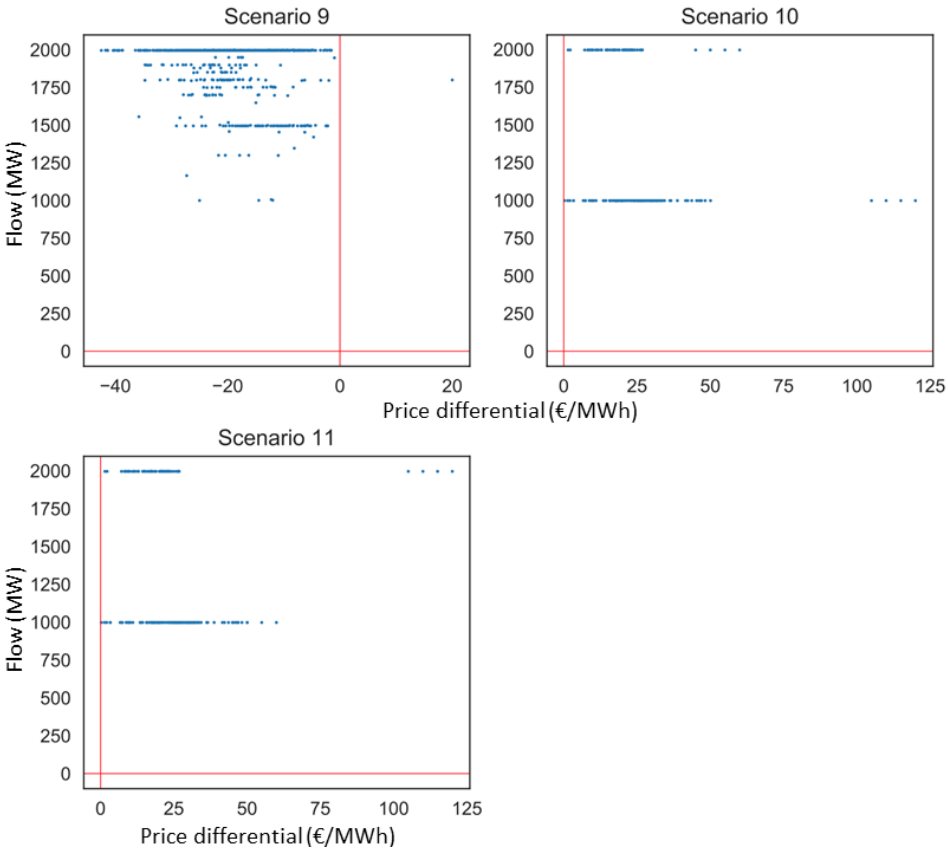

Figure 5.7. Scenarios 9–11: 1 inefficient flow and 0% inefficient flows.

Scenario 9 has just one efficient flow at 90%, yet *SCUWED* estimates only 10% inefficiency. All of the other examined metrics are able to detect the extremely high numbers of inefficient flows at large volumes. In this scenario, *UFAPD* and *WFAPD* are very similar to *UIIU* and *PWIIU* as a substantial number of inefficient flows occurred at a high percentage of NTC. The four large favourable price differentials (>€105) in Scenario 10 are only captured at 50% NTC but they are captured at 100% NTC in Scenario 11. As *PWIIU* is weighted by price, it is the only metric between Scenarios 10 and 11 that detects a change (from 18.5% to 17.0%) whereas the other metrics retain their respective values. As NTC is constant and all flows are FWPDs, we see that for scenarios 10 and 11 $UIIU = 2(SCUWED)$.[85]

5.3.2 Evaluation against historical data

Historical data for the IFA and BritNed interconnectors from 1 Jan 2013 to 31 Dec 2018 includes periods in which markets were coupled and uncoupled. Forecasted NTCs for the day-ahead market are available from the ENTSO-E Transparency Platform (TP) and are used as a proxy for NTC. Day-ahead GB prices are sourced from Nord Pool N2EX prices. French

[85] See Appendix 5.5.

and Dutch power prices for the period 2013–2015 are from EPEX Spot; for 2015–2018 they are from the ENTSO-E TP. The flow data is the RTE (day-ahead) commercial forecast for IFA; for BritNed, scheduled commercial exchanges are from ENTSO-E in the first period (2013-2014) and simulated[86] in the second (2015-2018). In the calculations, we ignore samples where the price differential is equal to zero and cap[87] the flow series by the corresponding NTC and ignore any records when NTC was zero. Table 5.4 reports the data sources by time period.

Data	2013–2015	2015–2018
FR prices	EPEX	ENTSO-E
NL prices	EPEX	ENTSO-E
GB prices	Nord Pool N2EX	Nord Pool N2EX
IFA flows	RTE	RTE
BritNed flows	ENTSO-E	Simulated
IFA NTC	ENTSO-E	ENTSO-E
BritNed NTC	ENTSO-E	ENTSO-E

Table 5.4. Data sources by time series and historical period.

Table 5.5 reports the results for the metrics based by year for IFA and BritNed.

A. IFA									
Year	**N**	**N^+**	**N^-**	**N^0**	**UFAPD**	**WFAPD**	**SCUWED**	**UIIU**	**PWIIU**
2013	8739	7649	1090	0	12%	2%	8%	14%	4%
2014	8736	8371	361	4	4%	0%	1%	4%	0%
2015	8760	8019	736	3	8%	0%	1%	8%	0%
2016	8765	8573	141	51	2%	0%	7%	5%	0%
2017	8733	8624	20	89	0%	0%	8%	5%	0%
2018	8756	8600	27	128	0%	0%	7%	4%	0%

B. BritNed									
Year	**N**	**N^+**	**N^-**	**N^0**	**UFAPD**	**WFAPD**	**SCUWED**	**UIIU**	**PWIIU**
2013	8630	7222	1394	14	16%	3%	14%	18%	7%
2014	7542	7093	449	0	6%	0%	2%	6%	1%
2015	8630	8122	505	3	6%	0%	5%	7%	1%
2016	8678	8493	185	0	2%	0%	5%	4%	0%
2017	8652	8418	234	0	3%	0%	8%	6%	1%
2018	8631	8282	347	2	4%	0%	12%	9%	1%

Table 5.5. Annual historical dataset results (Panel A. IFA; Panel B. BritNed) for the examined metrics. EUPHEMIA day-ahead market coupling was implemented in early 2014. Results are reported up to 1 significant figure. N^+, N^-, and N^0 indicate flows in the correct direction, in the wrong direction, and no flows, respectively.

[86] Due to data unavailability, we used the same simulation as Guo *et al.* (2019).
[87] If a flow of 1,665 MW occurred when NTC was only 1,500 MW, we reset the flow to 1,500 MW.

5.3.2.1 Years 2013–2016

All metrics show a general decrease in inefficiency between the year before market coupling (2013) and the years after coupling (2014-2018). Although the level of inefficiency could only be compared to a single pre-coupling year, a general decrease in inefficient interconnector use was observed between GB and both France and the Netherlands after day-ahead coupling went live in 2014.

Interestingly, there was a slight deterioration in 2014–2015. In 2015, *SCURED*, *UIIU* and *PWIIU* see an increase in inefficiency. This is due to the large utilisation of NTC by an increasing number of inefficient flows compared to the previous year. The average % NTC utilisation decreases in 2015 and 2016. Finally, the increase in the number of no-flows (N^0) is only recorded by the new metrics *UIIU* and *PWIIU*, and not by others.

The aforementioned deterioration might be explained by the fact that coupling does not always result in a decrease in FAPDs, which was observed when the Italian market was price-coupled with France, Austria and Slovenia. (See European Commission, QREEM Q1-2015, Section 4.4.). During this period, there was a shift from price coupling to flow-based market coupling, which might explain these results, since the new coupling process is predominantly based on flows as opposed to both flows and prices (Van den Bergh *et al.*, 2016).

5.3.2.2 Market coupling during years 2016–2018

Most indices for IFA measure more efficient interconnector trading in 2018 compared to 2017 and 2016.[88] *UFAPD* and *WFAPD* show a near-zero level of inefficiency in 2018 that the other metrics do not exhibit, as they are over-reliant on inefficient flows and ignore NTC utilisation inefficiency. An understanding of the reasons behind this improvement requires additional analysis, potentially using our metrics as explanatory variables in regression analysis. The markets are perfectly coupled after adjusting the loss factor for IFA of 1.17% and for BritNed of 3%. The reasons for non-zero FAPDs and *WFAPDs* are: (i) using the unadjusted price differential; and, (ii) publicly available data from ENTSO-E and RTE data contains several reporting issues. It is also possible for part of this to be a result of improvements through learning-by-doing in electricity trading after the implementation of market coupling rules in 2014.

5.3.2.3 Market coupling analysis using monthly intervals

At monthly intervals, the historical data produced periods similar to our stress data in which the existing metrics do not fully incorporate the interconnector utilisation information (NTC, flow direction, price differential) and, when compared to either of the new metrics, varied substantially. In these instances, the two new metrics, *UIIU* and *PWIIU*, provide greater accuracy.

[88] Not for BritNed as the data is simulated under the assumption of perfect market coupling (after taking the Mid Channel loss factor into consideration).

Examples of these occurrences and discrepancies between metrics for selected years are shown in Appendix 5.6, in Table 5.A8 for IFA and in Table 5.A9 for BritNed. In October 2016 *UFAPD* and *WFAPD* understate the degree of interconnector inefficiency due to the low number of FAPDs.[89] In February 2015, a high number of FAPDs (156) leads to *UIIU* reporting a larger inefficiency than *SCUWED*. Once price-weighting is considered, *PWIIU* reports a lower inefficiency than most other metrics.[90]

5.3.3 Discussion

The two new metrics we have introduced in this paper are able to compare both coupled and uncoupled markets on the same scale, and this enables them to outperform metrics that are currently used to measure inefficient trading, with the proviso that they are based on commercial incomes that may not properly measure social value.

5.3.3.1 Limitations of current metrics

The most commonly used metrics to measure trading efficiency, *UFAPD* and *WFAPD*, were introduced in parallel to major market coupling initiatives that took place in the last quarter of 2010 across Europe, including price coupling in the Central-Western European (CWE) region and volume coupling in the CWE-Nordic region (EU Commission, 2010b). After these initiatives were introduced, inefficient flows largely decreased, nearly disappearing in Q1-2011 in CWE (See EU Commission, 2012-Q3; 2012-Q4). Existing metrics are biased by inefficient flows and this limits their utility for evaluating the level of inefficiency of available cross-zonal capacity utilisation. Inefficiency should not only be a measure of inefficient flows, but also one of underutilisation of the available capacity when it is efficient to import or export electricity.

The development of the *SCURED* index (ACER/CEER, 2012) occurred after most market coupling initiatives were put in place. This measure was mainly used when inefficient flows were expected to be small, which may explain the bias of efficient flows and the poor performance of this measure in scenarios with inefficient flows. The left panel in Figure 1 suggests a situation where cross-zonal exchanges between the Belgian and Dutch markets in Q1-2011 were in the correct economic direction 99.99% of the time capturing small price differentials close to €1/MWh at 70% of the interconnector's capacity. As *SCURED* focuses on beneficial capacity utilisation, it inclines toward reporting an inefficiency of 30%, but this is an underestimate of the monetary inefficiency as 53% of total mark-up (€1.8m/€3.4m) was exchanged during inefficient flows. This shortcoming is caused by it focusing on the volumetric dimension and ignoring inefficient flows and price differentials.

Despite their shortcomings, one key benefit of *UFAPD*, *WFAPD*, and *SCURED* is their ease of implementation, as they do not include information about the level of electricity loads or generation and as such can be replicated using simple methods and the use of publicly

[89] Delving into the data reveals the average absolute utilisation of NTC at 80.1% for IFA over that period.

[90] The data reveals that for that period, FAPDs occurred at an average of €1.16 and FWPDs at €10.49.

available price and flow data. This is in contrast to metrics from electricity system models, which estimate the impact of market coupling in terms of social costs and benefits.

5.3.3.2 Added value of new metrics

Our new measures, *UIIU* and *PWIUU*, address the shortcomings of such metrics by including the dimensions that each of those metrics lack. The similarity between the new metrics, *UFAPD*, and *SCURED*, is such that under special circumstances, *UIIU* can be described as a function of those two as in Equation 6. *UIIU* and *PWIIU* can be considered generalisations of *UFAPD*, *WFAPD* and *SCURED*.

If all flows are FWPDs, *UFAPD* and *WFAPD* will measure perfect interconnector utilisation by recording a value of 0% inefficiency. Yet as was shown in relation to the stress and historical datasets, this will not be the case if the capacity of the interconnector is not fully utilised. *UIIU* and *PWIIU* include available NTC as a variable so are more accurate. Conversely, if inefficient flows are more likely, *SCURED* will underestimate the true inefficiency. Again, as *UIIU* and *PWIIU* consider inefficient flows, they will provide a higher degree of accuracy.

The computational requirements of *UIIU* and *PWIIU* are similar to the other metrics and can be implemented in a spreadsheet using built-in functions. To simplify this process, we have included two example spreadsheets, documented in Appendix 5.5.

5.3.4 Limitations of the new metrics

The third term in Equations 5.4 and 5.5 deal with occurrences of no-flows in the presence of a non-zero price differential. There is however a discontinuity in the S-curve (see Figure 5.A3) when the price differential is exactly zero. From an arbitrageur's perspective it would be uneconomic[91] to import/export electricity if prices in both markets were in equilibrium and flows across interconnectors can occur for reasons other than economic profitability. We have ignored zero price differentials[92] across all of our analyses by filtering out all occurrences. With full price convergence across the IEM, the tendency is for prices across different regions to equilibrate over time and result in greater occurrences of price differentials being exactly equal to zero. While an increasing number of such occurrences will diminish the accuracy of *UIIU* and *PWIIU*, such situations are highly unlikely.

Post market coupling data such as cross-zonal flow, electricity price and NTC have become available for several markets for recent years, since market coupling commenced, but data are limited for the pre-coupling period. For this reason, we focused on one interconnector (IFA) and one market coupling model (FBMC). Widening the scope of the analysis to include other market coupling models and/or other interconnectors would provide additional evidence to measure the benefits of the new metrics.

[91] Due to friction costs such as bilateral credit limits, exchange margining, etc.

[92] The simulated dataset did not include any zero-price differential. In the six-year historical dataset, our calculations showed only 5 hours of zero price differential.

As the new metrics measure the distance from the efficient *S-curve*-shaped trading pattern, they do not account for operational/engineering constraints in the interconnector that might have resulted in apparently inefficient flows, or lack of flows during an existing price differential. Such inefficiencies would be incorrectly captured by *UIIU* and *PWIIU* and would result in an overestimation of the inefficiency. Any model or metric will be limited by the quality of the data being analysed.

Interconnector transmission losses may affect estimations unless accounted for. Losses imply a discontinuity in the S-curve, so an interconnection flow at a zero-price differential (not loss-adjusted) is an inefficient flow, incurring avoidable losses. Also, there are ramping constraints that limit the rate of change of interconnector flows (e.g. 1%/minute maximum change), which can cause apparently inefficient flows if there are large price swings (e.g. caused by the one-hour time difference between GB and France during the early morning rise in demand). Neither of these system characteristics are considered by any of the metrics although they may indicate the need to study the hourly evolution of flows.

Finally, the metrics deal with market prices and revenues, and in the presence of asymmetric carbon prices, these will not reflect social values, nor the social value of trade. Additional measures would be needed to uncover and measure such inefficiencies.

5.4 Trading inefficiency and market coupling

We use an econometric model to define the annual average degree of utilisation inefficiency of the interconnectors between Great Britain and France (through IFA) between 2014 and 2019,[93] as well as between Great Britain and the Netherlands (through BritNed) between 2015 and 2018,[94] by assuming the presence or absence of market coupling.

We simulate a situation, during the period 2014–2019, where GB is assumed uncoupled from France and the Netherlands and compare our results with actual data where markets are coupled. This will also allow us to obtain valuable insights on the potential economic impact of market uncoupling, hence on the impact of a no-deal Brexit on cross-border trade. We investigate potential economic losses by considering how uncoupling is likely to impact net electricity imports, price differentials, trading inefficiency, and the private and social value of GB's two main interconnectors in this period, IFA and BritNed. In this analysis, using the estimated parameters from Guo *et al.* (2019),[95] we also simulate the cases with the GB Carbon Price Support (CPS) removed. This examines the impacts of market uncoupling if the CPS is abolished or extended to other EU countries. Further details about the methods used in this part of the paper are provided in Appendix 5.7.

[93] Electricity years run from 1 April to 31 March.

[94] Due to data availability issues, we use the simulated the day-ahead scheduled commercial exchange for BritNed from Guo *et al.* (2019).

[95] In particular, the partial effects of interconnector flows on the GB-FR(NL) price differential, and the partial effects of the CPS on the GB-FR(NL) price differential.

The results relating to the impact of market coupling on trading inefficiency, price differentials, net import, congestion revenue, and infra-marginal surplus are reported in detail in Appendix 5.8. Here, we provide a summary for each interconnector.

5.4.1 IFA interconnector

Market coupling led the price differential between GB and France to fall by €0.26/MWh (2%), net imports into GB to increase by 2.3 TWh (or by 22%), congestion income to increase by €14m (or by 6%), and infra-marginal surplus to increase by €3m (or 25%).

We compare the inefficiency of the coupled and uncoupled markets using the examined trading inefficiency metrics, with results shown in Table 5.A12. Market coupling reduced the inefficiency of cross-border trading. On average, during 2014–2019, the share of FAPDs fell from 12% to 3%, and the Weighted FAPDs (*WFAPDs*) from 1.6% to only 0.1%. *PWIIU*, *UIIU*, and *SCURED* also considerably decreased.

We also simulated the cases where the GB Carbon Price Support (CPS) is removed, finding that when GB and French day-ahead prices are reasonably close (in 2016–2018), and when markets are uncoupled, all metrics of inefficiency would be significantly higher than the cases where the CPS has been implemented and the GB price is much greater than the French price. This is because when prices are closer together, it is more difficult to accurately forecast the sign of the price differential between two markets, and hence to choose the trade direction, resulting in greater trading inefficiency by some measures (although with small price differentials the welfare cost is low).

Without the CPS, average differences in prices (€/MWh), net imports (TWh), congestion income (€m), and infra-marginal surplus (€m) for coupled and uncoupled trading over IFA between 2016-2018 are reported in the last three rows of Table 5.A11. The impact of uncoupling on congestion income and infra-marginal surplus would have been slightly higher than with the CPS. This is, again, because the comparable price levels bring more uncertainty towards the sign of the price differentials as well as the efficient direction of the flows. Specifically, with uncoupling, congestion income would on average have fallen by €19m/yr without the CPS, compared to €14m/yr with the CPS, a difference of 2% of the coupled congestion income, and the difference in the loss of infra-marginal surplus is less than 1% of coupled congestion income.

5.4.2 BritNed interconnector

The impact of market coupling on BritNed is shown in Table 5.A15. Similarly to IFA, market coupling facilitates price convergence, and raises congestion revenue and infra-marginal surplus. GB also imported more because the GB price was almost always greater than the Dutch price during 2015-2018.

On average, market coupling reduced the price differential between GB and the Netherlands by €0.09/MWh (by 0.6%), increased net imports into GB by 0.42 TWh/yr (by 5.6%), raised congestion income by €1.9m/yr (by 1.5%), and boosted infra-marginal surplus by €0.9m/yr

(by 8.6% of uncoupled infra-marginal surplus). The impact of market coupling on BritNed is smaller than that on IFA. This is not only because of BritNed's lower capacity, but also because the price differential between GB and the Netherlands is much larger than that between GB and France, meaning there is less uncertainty on the sign of the GB-NL price differential. Relative to IFA, uncoupling BritNed would have a lower impact on FAPDs as well as congestion income and infra-marginal surplus.

Similarly to IFA, the removal of asymmetric carbon taxes would result in spot price convergence between GB and the Netherlands. As a result, uncoupling the interconnector would have slightly higher relative impact on congestion income and infra-marginal surplus.

Table 5.A15 compares trading inefficiency for BritNed, with and without market coupling during 2015-2018. Again, uncoupling increases trading inefficiency. *UFAPD* (*WFAPD*) increased from 3% (0.1%) to 7.9% (0.7%). *SCURED*, *UIUU*, and *PWIIU* also substantially increased.

It is also worth mentioning that the metrics ($I_{1\text{-}5}$) shown in Table 5.A15 based on uncoupled markets during 2015-2018 are smaller than the metrics in 2013, where BritNed was also uncoupled. This is because in 2013, the average GB-NL price differential was €7.1/MWh, much lower compared to 2015-2018, as shown in Table 5.A15 (on average €15.2/MWh under market coupling). This confirms our earlier finding where if prices are closer together, uncoupling would have a more negative relative impact on trading inefficiency (although in absolute terms as the prices are closer, the gains from trade are smaller, amplifying the proportional inefficiency).

Without carbon tax asymmetries, the electricity prices between GB and both France and the Netherlands would converge. As a result, the impact of market uncoupling would lead to large changes in the volume of trade but the value of that trade would be lower. Removing carbon tax asymmetries would reduce deadweight losses and improve social welfare, demonstrating that these measures based on commercial income are not necessarily a guide to sensible decisions that should be based on social welfare.

5.4.3 Discussion

Interconnectors have provided welfare benefits to electricity systems, and these have been increased where market coupling has been introduced and the coupled markets are workably competitive and undistorted (Newbery *et al.*, 2019). Our analysis suggests that trading in an uncoupled market could increase the inefficiency of cross-border trading between GB and both France and the Netherlands unless compensated by trading on local power exchanges and buying physical capacity on interconnectors ahead of time.[96] It discourages market price convergence (not the same as social cost convergence), yielding a

[96] The simulations used to measure the impact of uncoupling do not model such compensatory actions by traders, and so exaggerate the inefficiency, perhaps considerably.

3% larger GB-FR average price differential relative to market coupling. Risk-averse traders may not make full use of capacity on IFA and market uncoupling could result in some reduction in congestion revenue, result in suboptimal use of the interconnector and an attendant very slight loss in infra-marginal (market, not social) surplus.

GB's day-ahead price is typically greater than the French day-ahead price, partly due to asymmetric carbon taxes between the two markets. As a result, with the French market closing before the GB market, despite uncoupling bringing uncertainty about subsequent GB prices, a trader would still believe that GB's price would most likely be greater than the French price, and would therefore schedule to import electricity most of the time. When the price differences are predicted to be small, the imported amount could be lower, resulting in inefficient use of the interconnector, although the value of the loss would also be small. The impact of market coupling on BritNed is similar, but smaller due to the lower NTC as well as the greater GB-NL price differential.

We also find that, if the British Carbon Price Support (CPS) asymmetry were removed, ideally by the EU implementing an equivalent CPS across its member states, then GB prices would converge to Continental market prices. In such cases the impact of market coupling on traded volumes would be higher than with the asymmetric carbon tax (but not the absolute value of congestion income, which would be smaller). Again, it needs stressing that removing the asymmetry would deliver welfare gains that would likely outweigh the impact of uncoupling.

5.5 Conclusions and policy implications

Monitoring the efficiency of electricity trades between countries guides policies designed to improve market integration such as market coupling, integrating balancing and investing in new interconnectors. Regulators are familiar with the *UFAPD*, *WFAPD*, and *SCURED* metrics, which have been widely used in measuring the success of market coupling. Using both hypothetical market conditions and historical data, we have shown that these metrics rely too much on either inefficient flows (the indices *UFAPD* and *WFAPD*) or efficient flows (*SCURED*). The new *UIIU* and *PWIIU* metrics that we have proposed address these shortcomings and perform better for both uncoupled and coupled market trading, facilitating comparisons between countries and over time. They are not affected by extreme price and flow differentials, and consistently define the degree of trading inefficiency under numerous potential market conditions.

Market coupling in the EU Internal Electricity Market was designed to reduce trading inefficiency. The current Flow-Based Market Coupling (FBMC) adapted into the EUPHEMIA algorithm is one of several available coupling models to have been adopted in the EU (EU Commission, 2010), in addition to others such as Interim Tight Volume Coupling (ITVC) and Price Coupling. We have shown that current metrics can substantially overstate or understate the benefits of market coupling, which could underpin poor market design decisions in the future. Adopting our new metrics would give a more accurate picture of trading inefficiency and aid policy development to improve market operation. If the UK

markets are uncoupled from neighbouring markets once it has left the EU, then the new metrics could be used to more accurately identify and minimise trading inefficiencies.

We found that uncoupling the UK markets would increase inefficient trading. It could lead the price differential between GB and France (the Netherlands) rising by €0.26/MWh or by 2% (by €0.09/MWh, or 0.6%), net imports into GB decreasing by 2.3 TWh or 22% (0.4TWh/yr, or 6%), congestion income decreasing by €14m, or 6% (€2m/yr, or 1.5%), and infra-marginal surplus decreasing by €3m, or 25% (€0.9m/yr, or 9%).

The benefits of market coupling increase with interconnector capacity, and decreases with the average price differential, here a larger price differential implies less uncertainty about the sign of the price differential and therefore on the direction of flow. Determining the efficient flow direction will become harder under uncoupling as price differentials fall as a result of planned new interconnectors and if European price differentials narrow due to the removal of the Carbon Price Floor in the future, although the value of this loss of predictability will be smaller with smaller price differentials.

6 Conclusions

This report considered several topics concerning cross-border electricity trading between Great Britain and its European neighbouring countries. It began by providing a qualitative assessment of electricity trading via interconnectors (Chapter 2). It then quantitatively analysed the value of British interconnectors over various timescales (Chapter 3); the impact of the British carbon tax — the Carbon Price Support — on the domestic and foreign electricity wholesale markets (Chapter 4); and derived robust metrics of international electricity trading inefficiency that outperform current metrics widely used by GB and EU regulatory bodies (Chapter 5). Finally, in this chapter (Chapter 6), we summarise the main conclusions drawn from each of these studies and present their policy implications.

6.1 The value of GB interconnectors

Chapter 3 quantified and appraised the efficiency of electricity trading between GB and the electricity markets interconnected to GB. It examined the efficiency and value of coupled and uncoupled trading for the GB-linked interconnectors over various timescales, covering year-ahead to intra-day markets. It considered whether coupling GB interconnectors to Continental Europe and the island of Ireland has eliminated previously inefficient trading. It quantified the commercial value of GB interconnectors and the infra-marginal surplus and deadweight losses caused by the asymmetry of carbon prices, thus calculating the social welfare benefits that are not reflected in the commercial benefits to interconnector owners. Finally, it investigated whether trading ahead on power exchanges and over the interconnectors has converged after implementation of the EU market coupling regulations and discussed the extent to which market decoupling after withdrawal from the European Union would reduce trading efficiency.

The study argued that the private – or commercial – benefits of GB interconnectors to France and the Netherlands are large relative to the costs of the interconnectors. This means that current interconnectors to GB are highly profitable investments. The cap and floor regime, which was introduced in 2013, was designed to encourage merchant investment in interconnectors while respecting the EU Regulation on interconnection. It is intended to strike a balance between commercial incentives and appropriate risk mitigation for project developers and does so by charging consumers for shortfalls in interconnector revenues lower than a regulated threshold in return for a cap on revenue and transferring the excess to consumers. By underwriting the floor and thus reducing risk, which is arguably the greatest barrier to these multi-billion-pound subsea cable investments, investor confidence grew substantially and proposals for new interconnectors began flowing in. In 2013, GB only had 4 GW interconnector capacity in 2013. After the scheme went live an additional 1 GW to Belgium was built, while a further 4.8 GW is under construction,[97] and up to 20 GW of additional interconnection capacity has been proposed.

[97] https://www.ofgem.gov.uk/electricity/transmission-networks/electricity-interconnectors

Most of these investments have already been shown to be potentially highly valuable to GB electricity consumers and society as a whole.[98] However, the now high level of the GB Carbon Price Support (CPS) that is not matched by comparable carbon taxes abroad, has amplified the commercial attraction of interconnection. Even if some of this is clawed back through the revenue cap that only applies to the GB share of these interconnectors.

The study also showed that the commercial benefits to Britain, France and the Netherlands have been amplified by the proliferation of increasingly liquid markets over timescales from more than a year-ahead to intra-day trading. While auctions for interconnector capacity provide transparency, they currently have less liquidity than day-ahead auctions. Given the limited transparency and liquidity of short-term physical markets, it is difficult to choose an efficient portfolio of contracts from domestic and foreign generators. Efforts to increase liquidity and transparency of short-term markets, for example through increased use of short-term electricity platforms, would allow capacity owners to more easily observe and profit from observed price differentials. The increasingly liquid nature of newly established markets over more extended timescales are critical for improving the business case for new interconnectors, so should form the basis for new investment proposals. However, for efficiency benefits to be locked in it will be increasingly important for these markets to be harmonised across borders and coupled.

We also found there are additional social benefits in lowering the GB wholesale price by substituting cheaper imports for more expensive generation that are not fully captured by trading from substituting cheaper imports for more expensive local generation. However, these are more than offset by the distortions caused by asymmetric carbon taxes. The commercial value of interconnectors to France and the Netherlands is substantial, with a combined value of €525 million/yr, including the value of the capacity contribution to security of supply of €40 million/yr and of ancillary services of €100 million/yr.[99] During 2015-2018, the social value is, however, increased by about €18 million/yr from the avoided infra-marginal generation cost, but reduced by the distortion caused by the CPS in GB that are not charged by our neighbours of €28 million/yr. In addition, the CPS increases imports from France and the Netherlands by 12.5 TWh/yr, increases interconnector revenue by €133 million/yr, half of which goes to France, and reduces GB carbon tax revenue by €103 million/yr, all relative to a counterfactual in which the CPS were not introduced.

[98] Ofgem (2014) Near-term IC cost-benefit analysis; Pöyry (2012) Impact of EMR on interconnection; Redpoint (2013) Impacts of further electricity interconnection on Great Britain; Aurora (2016) Dash for interconnection; National Grid (2014) Benefits of interconnectors to GB transmission system; EU Commission (2015) e-Highway2050; European Network of Transmission System Operators for Electricity (ENTSO-E) (2014) Ten-Year Network Development Plan 2014; SEM Committee (2011) Proposed Costs and Estimation of Benefits of the Introduction of Additional Intra Day Gate Closures in the SEM – Information Paper, SEM-11-023; Newbery et al. (2013) Benefits of an Integrated European Energy Market: Final Report for DG ENER; National Grid (2015) Electricity Capacity Report.

[99] Ancillary service revenues are commercially confidential, but the annual accounts of BritNed suggest that non-arbitrage income can be large at around €50 million/yr, although this might include other trading activities including foreign exchange gains. Noting that IFA has twice the capacity of BritNed leads to this very rough estimate of the total ancillary service and other revenues from both interconnectors.

We have explored the efficiency of trading on the Day-ahead Market (DAM) auction platform before and after market coupling, establishing that market coupling has indeed created efficient trading at the day-ahead stage between GB and both France and the Netherlands. The arbitrage revenue for trading capacity on the DAMs for IFA and BritNed averages about €100 million/GWyr, or €300 million/yr for both. This is a substantial amount, showing that the value of arbitrage alone provides a large contribution in establishing profitability for these interconnectors. It is critical to note that market coupling improves price discovery and market transparency, increasing traders' predictive power. But while it promotes low price differentials, arbitrage revenues are still considerable. With liquidity in new markets increasing, the establishment of additional markets at more fragmented timescales could maintain or even improve the profitability of interconnectors, which could help create a more secure, cheaper and sustainable electricity system.

The Single Electricity Market (SEM) of the island of Ireland was only recently coupled on 1 October 2018, and since then the DAM auctions have efficiently used the available interconnector capacity. Before coupling, SEM and GB had been trading inefficiently, with flows in the wrong direction nearly 50% of the time. This also led to losses that the regulators estimated for 2010 as €30 million/yr, but these seem to have disappeared as a result of coupling, emphasising the importance of the EUPHEMIA algorithm in inducing maximal efficiency of electricity exchanges.[100]

Trading after the DAM closes allows adjustments to be made, and GB often revises its off-peak position to secure flexibility when fossil fuelled generation is at minimum load and pumping at maximum. We deduce that adjusting imports intra-day and in balancing markets where these are shared (as they are with the SEM)[101] is a useful balancing option. Yet with a uniform carbon tax across Europe, trading and balancing would converge more easily due to prices being closer together, which would help improve the economics and deployment of low-carbon generation from renewables and nuclear power.

Policies to improve shared balancing services (difficult given the priority each System Operator accords to providing domestic security of supply) could also be useful to enable interconnectors to deliver greater value. Given the cap and floor system currently in place, such policies should result in both lower costs for consumers and greater investor confidence.

There are active forward markets for annual, seasonal, quarterly and monthly Physical Transmission Rights (PTRs). For IFA, about 93% of the available capacity is sold in four separate auctions, of which 50% is for the calendar year. The 2015 PTR auctions traded at a substantial premium (about 35%) to the cost of securing an equivalent baseload supply in the DAM, but this premium almost disappeared in the following years, consistent with

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

[101] Albeit subject to veto from either System Operator after the intra-day markets have ended.

growing familiarity with, and liquidity of, the PTR auctions. Hedging using Contracts for Difference (CfDs) on local power exchanges appears to offer almost as good a hedge as PTRs, again after the first year (2015). Yet local CfDs appear more sensitive to news about major technical conditions, such as those associated with power outages that are alleviated in the DAM auctions as wider areas are coupled.

At the time of writing, the future relationship of GB with the rest of the EU is unclear. The UK Government has advised that DFTEU may lead to alternative trading arrangements between Great Britain and the EU. These arrangements may not include the present coupled day-ahead markets, which might lead to a loss of some of the coupling benefits.

Yet trading CfDs on neighbouring power exchanges supplemented by PTRs (as used before coupling) might deliver most of the trading benefits (although not address the imposition of additional transmission charges). Even if uncoupling meant PTRs no longer allowing financial settlement, CfD markets in neighbouring countries should offer additional hedging, facilitating efficient flow and reducing the costs of uncoupling. If exchanges offered CfDs for individual hours, paying the difference between markets, and interconnector operators allowed market participants to buy and schedule intraday capacity and receive this same settlement, it would make it easier for capacity to be used efficiently. Cooperation between interconnector operators, exchanges, and system operators in the two regions would be required to minimise mismatch between the different settlements which might expose participants to risk.

There would seem little to prevent setting up a similar DAM and IDM in GB for trading over the interconnectors, although it would not capture all the benefits of a pan-European simultaneous auction. It might even allow rather different and possibly improved auction bid formats. Such an option should be explored in detail by encouraging bilateral arrangements between neighbouring System Operators to minimise the potential disruptions from market uncoupling.

In the absence of additional opportunities to schedule, this would require long-term capacity holders to manually schedule their capacity one or two days ahead. This prevents capacity holders from being able to guarantee a profit, however it is also likely to increase the divergence between the day-ahead prices in the two markets, thus increasing the potential revenue for capacity holders. It is also likely to increase the opportunities to profit in the intra-day capacity markets, as participants are able to correct for flow that has been incorrectly scheduled from what transpires to be high price to low price regions.

The interconnector operators may also create additional opportunities for capacity to be scheduled. For example, they could allow capacity owners to carry long-term capacity that isn't already scheduled into the intra-day market. In addition, they could create a mechanism to automatically buy in one market, sell in another, and flow, where profitable opportunities remain close to delivery.

6.2 The impact of a carbon tax on cross-border trade

In Chapter 4, we investigated the impact of GB's carbon tax, the Carbon Price Support, on cross-border electricity trading, both theoretically and empirically. We did so by providing a social cost-benefit framework to show how the carbon tax impacts cross-border trade.

Firstly, we consider that the CPS has been widely successful having delivered dramatic reductions in carbon-intensive electricity generation that have nearly completely pushed coal off the system. We considered the associated side effects of the policy and established that its effects on trade distortions are likely small compared to the large social benefits of the policy.

We studied the impact of asymmetries in carbon taxes between connected countries on cross-border electricity trade, using GB's carbon tax (Carbon Price Support) as a case study. We demonstrated how the unilateral imposition of a carbon tax affects electricity prices, interconnector flows, and congestion income. We additionally measured the associated allocative inefficiency in which apparently lower priced foreign electricity that does not carry its full carbon cost displaces domestic electricity that would have been cheaper in the absence of a carbon tax, but now has a higher price. This distortion is the deadweight loss caused by the asymmetric carbon tax.

Market coupling ensures the efficient use of interconnectors so that the higher-priced market always imports electricity from the lower-priced market. A unilateral carbon tax distorts trade if it alters interconnector flows, resulting in deadweight losses. More generally, we find that any carbon tax transfers revenue abroad at a cost to the domestic economy, and that the higher the carbon tax, the higher the trade distortion or loss to the domestic economy. In light of these findings, and given the tax has already induced wide emission reductions – having led to a >70% reduction in coal generation from 2012 to 2016, a reduction in the share of coal in total generation from 40% in 2012-Q1 to 5% in 2018-Q4,[102] as well as a reduction in the price-setting hours from 31% in 2012 to 11% in 2017 (Castagneto Gissey *et al.*, 2018) – it is possible to argue that the Carbon Price Support level should be reconsidered in order to minimise trade distortions. A social welfare analysis could be useful to indicate whether a reduction in the carbon tax level is able to deliver a positive net social benefit by reducing trade distortions.

Our results show that over the last years, the Carbon Price Support has been fully passed through to the GB day-ahead price. During 2015-2018, the CPS increased the GB DAM price by roughly €10/MWh in the absence of trade adjustments. The price differential with our neighbours fell to about €8/MWh allowing for displacement of expensive carbon-intensive generation with cheaper imports, thereby increasing electricity affordability and reducing consumption of polluting generation. The CPS increased imports by 8.9 TWh/yr from France and by 3.6 TWh/yr from the Netherlands.

[102] https://www.ofgem.gov.uk/data-portal/electricity-generation-mix-quarter-and-fuel-source-gb

The increase in imports from the CPS reduced carbon tax revenue by €74 million/yr for IFA and by €39 million/yr for BritNed. Congestion income for IFA increased by €81 million/yr and for BritNed's by €52 million/yr, while the infra-marginal surplus from cross-border trading was around €15/million/yr for IFA AND €10 million/yr for BritNed. The summation of congestion income and infra-marginal surplus constitutes the social value of the interconnector. We estimated the deadweight loss due to the CPS was estimated to be €18.5 million/yr for IFA and €9.4 million/yr for BritNed. Allocative inefficiency has been shown to be reduced, with substantial distortions in trading patterns, yet the social welfare benefit from the CPS is likely to be many times higher than the loss from trade distortions, with coal having been nearly eliminated from the electricity system.

We showed a substantial reduction in the efficiency of cross-border trades. Asymmetric carbon pricing in two connected countries incur deadweight losses, resulting in less efficient cross-border trading. It might be possible that EUPHEMIA can be tweaked to allow more efficient trades with unilateral carbon taxes, given their legitimacy and contributions toward emission reduction, so we suggest this as an important direction for future research.

On average, about 18% of the increase in the GB day-ahead price from the CPS has been passed through to higher French prices and 29% to higher Dutch prices. We also found that a considerable proportion of the GB DAM price increase caused by the CPS was passed through over the interconnectors, both French and Dutch day-ahead prices have been slightly increased. This raised the countries' producer surplus but increased consumers' electricity costs. While this study has focused only on the impact on French and Dutch prices, it is likely there has been as similar spillover effect to Irish and Belgian day-ahead electricity prices. If our interconnected countries were to impose carbon taxes to reduce or remove this asymmetry, it is likely for these effects to be reduced, with the additional benefit of better addressing the climate change externality. While consumer prices would rise, so would tax revenue that could be used to reduce taxes on those same consumers (e.g. by funding other subsidies to renewables and efficiency, instead of levying these on consumer bills).

More generally, our results confirmed that the British CPS raised the GB spot price, reduced the convergence of cross-border electricity prices and increased GB imports of electricity. In other words, the CPS has made electricity more expensive to consumers in the domestic market and slightly more expensive in those markets interconnected with GB. The asymmetry of carbon taxing has reduced market integration between GB and its neighbours, raising price differentials, and increasing imports, displacing some domestic generation. On the other hand the CPS has accelerated decarbonising GB electricity, reduced the required subsidies to low-carbon generation, and increased tax revenue, while to some extent undoing the under-taxation of GB electricity through its reduced rate of VAT.

While the increase in congestion income mostly comes from GB electricity consumers it is shared equally by the Transmission System Operators in their roles as owners of the interconnectors. This increased congestion income might over-incentivise further investment in additional interconnectors, at least to carbon-intensive markets lacking such carbon taxes,

such as the Netherlands and Ireland. It is necessary to evaluate interconnector investment proposals on the basis of these findings to ensure that interconnector investments being pursued are socially optimal.

The objective of the British CPS is to reduce British CO_2 emissions and incentivise low-carbon investment, but this is partly subverted by increased imports of more carbon-intensive electricity. The same argument could previously be made that reductions in GB emissions are offset by increased emissions elsewhere, but this has been largely addressed by the EU Market Stability Reserve. In case further steps to impose a carbon tax across Europe are not taken rapidly, it is necessary to provide a European-wide analysis of the impacts of unilateral carbon taxes to understand how these increased incentives for carbon-intensive electricity generation are balanced out against reductions in carbon intensive generation in the domestic economy.

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

6.3 Measuring international electricity trading inefficiency

Monitoring the efficiency of electricity trades between countries is essential to ensure that policies designed to improve market integration – including market coupling and policies to spur investments in new interconnectors – deliver welfare gains.

In Chapter 5, we systematically reviewed the metrics regularly used by EU policymakers to measure cross-border electricity trading inefficiency. This was the first study to both qualitatively and quantitatively review the quality of current metrics of trading efficiency, as well as to classify these measures.

It is clearly desirable that countries trade efficiently. The benefits come in the form of more affordable, secure and lower-carbon electricity, as well as reducing domestic market power.

In this study, we identified and explained several deficiencies in current metrics, which cause their accuracy to vary greatly depending on the trading patterns. Using both hypothetical market conditions and historical data, we have shown that some metrics rely too much on inefficient flows (the indices *UFAPD* and *WFAPD*) or efficient flows (*SCURED*). These metrics are used every year (or quarter) in official reports by ACER and the EU Commission to measure the progress in improving the efficiency at which electricity trades between European countries occur.

We have developed two new metrics of market coupling that address these issues. Our *UIIU* and *PWIIU* metrics leverage available information on basic interconnector use such as

available NTC, flow direction, and price differential magnitude. Importantly, the new metrics are not impaired by the state of market coupling, which facilitates comparisons between countries and over time. We have demonstrated that the new indices are not affected by extreme price and flow differentials. They consistently define the degree of trading inefficiency under numerous potential market conditions, which both provides confidence and further emphasises the limitations of existing measures.

The principal benefit of using our metrics are greater accuracy and robustness to market and trading conditions relative to other metrics used to derive the departures of price and flow differential patterns from fully efficient trading. They also allow one to measure inefficiency regardless of whether the two markets in question are coupled or not, an issue which tends to skew many of the previous metrics.

We suggest future research to build a price and flow-weighted European-wide measure of trading inefficiency based on our model to allow hour-by-hour, real-time understanding of whether physical trades are occurring efficiently. This would enable policymakers to gain in-depth knowledge of the reasons for inefficient trade, which current metrics generally fail to deliver.

Given the improvements, we believe they should be used instead of existing metrics to measure the efficiency of electricity trading between countries and to evaluate the impacts of market coupling. This will enable a more accurate assessment of the extent of the inefficiency of cross-border trading and therefore lead to more informed appraisals on international trading regulations. Commercial decisions can also be supported to demonstrate the potential impact of existing and proposed interconnectors on the efficiency of cross-border trading, as well as to argue in favour or against certain changes in the electricity system which might affect the position of an interconnector's trades.

In this chapter, we also considered the impact of market uncoupling on cross-border trade, finding that market uncoupling would lead to more inefficient trading. It would also lead the price differential between GB and France (the Netherlands) to rise by €0.4/MWh or by 3% (by €0.3/MWh, or 2%), net imports into GB to decrease by 3.3 TWh or 34% (1 TWh/yr, or 15%), congestion income to decrease by €23 million, or 11% (€7 m/yr, or 5%), and infra-marginal surplus to decrease by €4 million, or 30% (€2 m/yr, or 19%).

We showed that the impact of market uncoupling (or in the opposite sense, of market coupling) tends to increase with the capacity of the interconnector, and to decrease with the average price differential. The latter implies less uncertainty on the sign of the price differential and therefore on the direction of flow; as a result, market uncoupling would result in greater inefficiency and a reduction in congestion income and infra-marginal surplus.

Finally, we showed that, should the EU decide to implement an equivalent carbon tax to GB's Carbon Price Support, electricity prices between GB and both France and the Netherlands would converge. In this case, the impact of market uncoupling could be more severe, and may potentially result in greater trading inefficiency and some welfare loss.

6.4 Concluding remarks

This report considered various aspects of interconnector economics and market coupling. It examined the private and social value of GB's interconnectors over markets at various timescales, the impact of GB's unilateral carbon tax on the domestic and foreign electricity markets and established new and more accurate measures of international trading efficiency.

We conclude that current GB interconnectors have large commercial (and social) value, that they are profitable investments, and that the markets created to cover various timescales are beneficial for their business case and improve liquidity. Price differentials with interconnected markets have increased due to the Carbon Price Support (CPS), which is reducing the competitiveness of GB generation, leading to higher GB imports. While the CPS has been successful in its main purpose of reducing CO_2 emissions, nearly eliminating coal-based generation, it has had a negative impact on trade efficiency, offsetting some of the benefits of market coupling. Measuring trade efficiency is difficult and current metrics can be highly inaccurate. We therefore designed two new metrics to measure trading efficiency that have substantial advantages over the metrics regularly used by policymakers. Finally, we show that market uncoupling could lead to increased trading inefficiency.

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8 Authors and institutions

This project brings together an experienced team with a track record of working across disciplines to advise electricity market policy through the application of state-of-the-art econometrics and energy modelling techniques. It combines expertise from UCL and the University of Cambridge.

8.1 Author biographies

8.1.1 University College London

Dr Giorgio Castagneto Gissey (University College London – PI) is a Senior Research Associate in Energy Economics and Policy at UCL. He is the Principal Investigator of this project, for which he has acted as Senior Consultant to Ofgem. He has published on electricity markets, including on market design, market power, market integration and policy incentives, on some of the most recognised energy economics and policy journals. He has received several high-profile grants or funding from, ESRC, EPSRC, InnovateUK, and BEIS, and Ofgem. His work has been widely cited by governments and private entities and his models have been used, licensed or purchased by multiple governments.

His work was featured in the media by outlets such as The Guardian, The Independent, S&P Global, The i, Business Standard, Utility Week, Energy World, Yahoo! News, The Big Issue, Energy Live News, Future Power Technology, and Outlook, among many others. He is Research Co-I on the 'Value of Interconnection in a Changing Electricity System' (ICE) project, a major project funded by RCUK and InnovateUK (~£1m), concerning increasing interconnection capacity on the GB and European wholesale electricity systems.

He has been Senior Consultant to Ofgem for investigations on competition and market power in electricity wholesale markets and was extensively cited in Ofgem's State of the Energy Market report. His research into the barriers to energy storage has led to multiple changes in regulatory policy. He is Research Co-I on the EPSRC-funded RESTLESS project (~£1.75m), leading on the economics of storage.

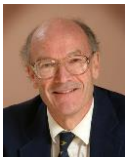
He has provided expert advice to Ofgem, BEIS and the UK Parliamentary Office for Science and Technology on various occasions about the role of interconnectors in the GB electricity markets and potential policies to internalise storage in electricity markets. He also provided advice to the consultancy Arup, on request of the Mexican Government. He advised the U.S. FERC in relation to electricity network modelling. He was an adviser to BEIS for their UK's Industrial Strategy Roundtable and to the Energy Saving Trust for the Community Energy Storage Roundtable.

He worked at UCL as a Teaching Fellow in Economics and Business, teaching many courses in advanced econometrics at all academic levels, and held positions at Imperial College, the Italian Ministry of the Economy and Finance, and the Italian National Research Council, and

was a Honorary Research Associate at UCL. He founded the UCL Energy & Resource Economics Group, which he regularly chairs, and holds an ESRC-funded Ph.D. from Imperial College.

Prof Michael Grubb (University College London – Co-I) is Professor of Energy and Climate Policy. He has substantial experience in the study of electricity markets and has published influential papers on the topic. His research and experience have grouped broadly around fiver main themes: (1) Study of electricity retail and wholesale prices; (2) Carbon pricing and emissions trading systems, including the design of the EU ETS and industrial competitiveness; (3) Energy systems and low carbon innovation, with emphasis upon the innovation process in the energy sector, particularly in relation to renewable sources and the design of support systems; (4) International climate change responses more broadly including the UNFCCC negotiations, the Kyoto Protocol and its Mechanisms, and the wider challenges of international cooperation; and (5) Integration of interconnectors and renewable electricity sources into electricity systems. He has published many leading papers in power system analysis.

He previously served as Chair of the UK Panel of Technical Experts on Electricity Market Reform, and a member of the CCC. An interdisciplinary researcher on the economics and policy of energy and climate change, he is PI on numerous projects, such as the ~£3m Green-Win project. Founding editor-in-chief of the journal Climate Policy, he was previously: Senior Advisor to Ofgem; Senior Research Associate at the University of Cambridge; Chair of the international research organization Climate Strategies; Chief Economist at the Carbon Trust; Professor at Imperial College London; Head of Energy and Environment at Chatham House. He is author of eight books, numerous research articles and publications on competition policy, and a Lead Author for several reports of the IPCC on mitigation, including the IPCC Fourth Assessment Report. Leading the analysis of market coupling, he brings regulatory and policy experience.



Prof Paul Ekins OBE (University College London – Co-I) is Professor of Resources and Environmental Policy and Director of the UCL Institute for Sustainable Resources. He is also Deputy Director of the UK Energy Research Centre, and the UKERC Co-Director leading on its Energy Resources theme. He was awarded an OBE in the UK's New Year's Honours List for services to environmental policy. He received a Global 500 Award 'for outstanding environmental achievement' from the United Nations Environment Programme.

He is a member of Ofgem's high-level Sustainable Development Advisory Group and was Chairman of the Government-funded National Industrial Symbiosis Programme (NISP), the UK's most successful programme to improve resource productivity. In addition, he is a member of UNEP's International Resource Panel; a Fellow of the Energy Institute; a Senior Consultant to Cambridge Econometrics; and he leads UCL's participation in the EPSRC SUPERGEN consortium on hydrogen fuel cells and on bioenergy research. From 2002-2008, he was a Member of the Royal Commission on Environmental Pollution. From 1997-2005, he

was a specialist adviser to the Environmental Audit Committee of the House of Commons, from 2003-2007 was a Member of the Government's Sustainable Energy Policy Advisory Board, and in 2007 was a Specialist Adviser to the Joint Parliamentary Committee on the Climate Change Bill.

He has extensive experience consulting for business, government and international organisations, which has included over 50 projects and consultancies over the last ten years, and many advisory positions. He has also been a consultant to the Government's Sustainable Development Commission, and an adviser to the UK Government's Advisory Committee on Business and the Environment and Round Table on Sustainable Development and has been a frequent contributor to His Royal Highness the Prince of Wales' annual course for senior executives on business and the environment at the University of Cambridge, and the Cambridge Programme for Sustainability Leadership. Since 2003, he has been a member, and is now Chairman, of the Judging Panel, UK Ashden Sustainable Energy Awards, and he is on the Judging Panel of the Rushlight and Rosenblatt New Energy Awards. He was a member in 2010-11 of two Ministerial Advisory Panels, on the Green Deal (DECC) and on the Natural Environment White Paper (DEFRA), and is on the Advisory Board of DECC's Energy Efficiency Deployment Office. In 2011 he was appointed Vice-Chairman of the DG Environment Commissioner's High-Level Economists Expert Group on Resource Efficiency and a member of the European Commission's high-level European Resource Efficiency Platform. With his wide market and regulatory experience, he will contribute toward the analysis of inter-market relationships and coupling.

Dr Paul Dodds (**University College London – Co-I**) is Associate Professor in Energy Systems in the UCL Energy Institute and the Institute for Sustainable Resources. He specialises in energy systems modelling and has particular interest in modelling hydrogen and bioenergy systems, and the importance of energy storage.

He has recently developed a new energy systems model, UK TIMES, to replace the UK MARKAL model. UK MARKAL contributed to UK energy policy over the last 10 years and UK TIMES has already been used by the UK Department of Business, Energy and Industrial Strategy to provide underpinning evidence for their fifth carbon budget impact assessment and for the Clean Growth Strategy. Paul has published papers on the design of energy system models, on hydrogen and on the future of the UK gas networks. He formalised a theoretical approach to analysing the evolution of energy system models using "model archaeology".

Paul's principle research interests lie in the interactions between society and the environment, with a particular focus on energy and food. He has coordinated the development of a new UK energy system model, the UK TIMES model, that has replaced the UK MARKAL model. UK MARKAL has profoundly influenced UK climate policy over the last few years and UK TIMES is expected to have a similar impact. As part of the model development process, Paul has made several methodological contributions towards improving the design of energy system models. He has formalised a theoretical approach to

analysing the evolution of energy system models using "model archaeology" and has published papers comparing approaches for representing the transport and residential sectors.

Paul has published a range of papers on socioeconomic challenges for hydrogen and fuel cell technologies, including exploring the potential for hydrogen to decarbonise heating and road transport. He has been at the forefront of efforts to identify future scenarios for the UK gas networks as an important policy and research issue for the UK, including publishing papers on the future of the networks, including conversion to hydrogen, and organising a workshop that brought together government, industry and academia. Paul's doctoral work focused on climate change and agriculture in Senegal. He characterised the effects of climate variability and change on the livelihoods of rural farmers and examined how agricultural adaptation could reduce climatic impacts. He created a new crop model to examine agricultural adaptation to climate change and specifically rainfall variability. This work built on his previous work on rainfall and evapotranspiration in the Murray-Darling basin in Australia. Paul has continued these interests at UCL through supervising a PhD student that is examining the impact of climate change and land degradation on global crop yields, in conjunction with IIASA. He is also interested in examining the importance of weather and climate data on energy generation and demand.

Guy Lipman (University College London – Researcher) is currently studying for an MPhil/PhD at University College London's Energy Institute, researching ways to promote the purchase of renewable electricity by companies and individuals. He has worked as a quantitative analyst for over a decade, including 7 years at Deutsche Bank, supporting electricity and natural gas traders in Europe, North America and Australia. This work focused in particular on modelling gas storage, electricity tolling, and option portfolios, as well as physical power and gas operations. He has also worked at EY and Deloitte, assisting commodities and financial services clients in the UK and Australia. Guy has a Master of Science in Philosophy of Social Sciences from London School of Economics, a Bachelor of Science (Honours) from the University of Melbourne, and a Bachelor of Commerce from the University of Adelaide.

Luis G. Montoya (Researcher) With over 12 years' experience in Energy markets, Luis Guillermo Montoya specialises in quantitative analysis and risk management. He has worked for energy trading houses such as Enron, RWE Supply and Trading, and Morgan Stanley. He holds a BSc. in mathematics from Sussex University and an MSc. in Financial Engineering and Quantitative Analysis from the ICMA Centre at Reading University.

8.1.2 University of Cambridge

Prof David Newbery (Co-I) is Emeritus Professor at the University of Cambridge and Professorial Research Associate at University College London. He has been Professor of Applied Economics since 1988 and was Director of the DAE from 1988-2003. He worked at the World Bank, where he became Division Chief of Public Economics from 1981-3. He has been a visiting Professor at Yale, Stanford, Berkeley and Princeton. He was an associate editor of The Economic Journal from 1977-2000 and President of the European Economic Association in 1996. He has written books on social cost-benefit analysis, commodity price stabilisation, taxation in developing countries, tax reform in transitional economies, and the privatisation, restructuring and regulation of network industries such as electricity, gas and telecoms. His articles cover economic theory, risk, futures markets, energy policy, agricultural price policy, tax policy, public goods, transport economics, international trade, industrial organisation, privatisation, regulation, environmental policy and reform.

He has worked with international agencies on tax reform in Europe and Africa, road user charging, energy policy and regulation of privatised utilities. He is currently working on regulation and privatisation, particularly of electricity and gas, and is Principal Investigator and Project Co-Leader on the Cambridge MIT Institute Electricity Project. He continues his interest in road pricing and transport policy. He was elected a Fellow of the Econometric Society, 1989, and of the British Academy in 1991. He was awarded the Frisch medal of the Econometric Society for applied economics in 1990, the Harry Johnson prize of the Canadian Economic Association in 1993, and the IAEE's 2002 Outstanding Contributions to the Profession Award. He was Member of the Monopolies and Mergers Commission (later Competition Commission) from 1996-2002 and of the DEFRA's Environmental Economics academic panel and chairman of the Dutch electricity market surveillance committee.

Bowei Guo (University of Cambridge – Research Co-I) is a Ph.D. Candidate in the Faculty of Economics of the University of Cambridge. He majored in Economics and Econometrics in his undergraduate studies at the University of Bristol. Bowei is currently working on the UK/Irish electricity retail market. An applied econometrician, he works on real-life data and seeks to find better policies that improve social welfare. He is an Associate Researcher of the Energy Policy Research Group, Cambridge Judge Business School, and has been a Research Assistant at Cambridge and UCL. He uses various econometric and machine learning tools to study demand response, low-carbon energy policy, cross-border energy trading, and wider environmental economics issues. His research interests include carbon pricing, CO_2 displacement of wind energy, spot market prices, and cross-border trading.

8.2 Institutions

University College London (UCL) is a public research university in London, England, and a constituent college of the federal University of London. The UCL Institute for Sustainable Resources delivers world-leading learning, research and policy support on the challenges of climate change, energy security, and energy affordability. We are part of The Bartlett School of Environment, Energy and Resources (BSERR), UCL's global faculty of the built environment. Our institute brings together different perspectives, understandings and procedures in energy research, transcending the boundaries between academic disciplines. They coordinate multidisciplinary teams from across the University, providing critical mass and capacity for ambitious projects. BSEER addresses the complex global challenges of transitions to sustainability in research and teaching. Its profile helps to deliver relevant Sustainable Development Goals on energy, water, food, infrastructures, industries, cities, and climate change as well as the UK Industrial Strategy, in particular 'place-based strategies'.

Our mission is to enable world leading research with innovative and novel methodologies and education for the leaders of tomorrow. Our ambition is to assess risks, solve problems and develop appropriate mechanisms to maximize our impact. Serving as a platform for four institutes, BSEER generates roughly £19m annually; it successfully runs programmes for approx. 130 PhD students and approx. 300 MSc and MRes students. We are dedicated to inter-and transdisciplinary systems thinking spanning environmental research, building physics, economics, policy and governance, data analytics, modelling, and more. Our current portfolio consists of £37m in research grants from major funders and scored as 4* world leading in the most recent REF.

The **University of Cambridge** is a collegiate public research university in Cambridge, United Kingdom. Founded in 1209 and granted a Royal Charter by King Henry III in 1231, Cambridge is the second-oldest university in the English-speaking world and the world's fourth-oldest surviving university. The history and influence of the University of Cambridge has made it one of the most prestigious universities in the world.

8.3 Authors list

Each of the studies presented in this report are authored as follows:

- **Chapter 1:** Castagneto Gissey, G.
- **Chapter 2:** Lipman, G., Castagneto Gissey, G., and Dodds, P.E.
- **Chapter 3:** Newbery, D., Castagneto Gissey, G., Guo, B., and Dodds, P.E
- **Chapter 4:** Guo, B., Newbery, D., and Castagneto Gissey, G.
- **Chapter 5:** Castagneto Gissey, G., Montoya, L.G., Guo, B., Newbery, D., Dodds, P.E., and Lipman, G.
- **Chapter 6:** Castagneto Gissey, G. and Newbery, D.

9 Appendix

9.1 Appendix 3 (Chapter 3)

Appendix 3.1. PTR Auction data.

Table 3.A1 compares the efficacy of hedging using the last price available of CfDs on power exchanges and PTRs secured at the latest auction in the month.

Monthly FR=>GB	PTR I	PTR II	DAM option	CfD last	CfD I	CfD II
Jan-15	€ 15.20	€ 15.23	€ 9.87	€ 15.15	€ 9.36	€ 10.28
Feb-15	€ 14.64	€ 16.53	€ 7.74	€ 5.49	€ 8.06	€ 7.03
Mar-15	€ 19.81	*€ 19.81*	€ 12.15	€ 14.92	€ 13.77	€ 14.86
Apr-15	€ 29.55	€ 26.54	€ 21.45	€ 19.10	€ 23.24	€ 21.85
May-15	€ 34.25	€ 36.60	€ 29.55	€ 28.66	€ 28.55	€ 28.09
Jun-15	€ 36.25	€ 36.34	€ 25.24	€ 28.02	€ 26.48	€ 27.95
Jul-15	€ 33.26	€ 34.00	€ 21.43	€ 20.48	€ 26.66	€ 28.36
Aug-15	€ 37.80	€ 25.45	€ 24.75	€ 28.87	€ 28.92	€ 30.83
Sep-15	€ 18.98	€ 18.42	€ 19.33	€ 19.36	€ 19.66	€ 18.74
Oct-15	€ 17.10	€ 14.49	€ 9.94	€ 15.62	€ 17.14	€ 17.16
Nov-15	€ 16.05	€ 14.97	€ 11.56	€ 12.21	€ 14.61	€ 14.54
Dec-15	€ 13.26	*€ 13.26*	€ 12.95	€ 16.06	€ 14.33	€ 13.46
Jan-16	€ 13.15	*€ 13.15*	€ 14.64	€ 11.49	€ 13.93	€ 14.47
Feb-16	€ 10.76	€ 9.34	€ 17.49	€ 11.11	€ 10.01	€ 10.72
Mar-16	€ 13.25	€ 14.05	€ 16.74	€ 15.98	€ 13.71	€ 14.72
Apr-16	€ 14.99	€ 15.01	€ 16.76	€ 17.82	€ 18.28	€ 17.29
May-16	€ 15.15	€ 15.12	€ 19.83	€ 17.97	€ 16.90	€ 17.25
Jun-16	€ 15.43	€ 16.65	€ 19.23	€ 19.72	€ 18.10	€ 17.84
Jul-16	€ 15.75	€ 17.16	€ 14.52	€ 16.94	€ 19.66	€ 19.00
Aug-16	€ 15.01	€ 12.79	€ 11.83	€ 16.06	€ 16.72	€ 15.77
Sep-16	€ 7.05	€ 6.95	€ 16.36	€ 6.91	€ 13.47	€ 11.52
Oct-16	€ 3.60	€ 2.23	€ 0.09	€ 16.52	€ 9.67	€ 10.55
Nov-16	€ 5.01	€ 5.01	€ 3.33	-€ 4.88	€ 5.68	€ 8.04
Dec-16	€ 6.03	€ 4.34	-€ 1.88	-€ 10.21	-€ 39.66	-€ 13.59
Jan-17			-€ 16.63	€ 0.57	-€ 0.18	€ 5.82
Feb-17			€ 6.50	€ 1.12	€ 8.50	€ 0.23
Mar-17	€ 8.51	€ 8.21	€ 13.04	€ 10.89	€ 9.36	€ 9.38
Apr-17	€ 14.30	€ 15.55	€ 13.65	€ 16.63	€ 16.09	€ 17.54
May-17	€ 13.66	€ 12.36	€ 13.93	€ 14.89	€ 13.86	€ 13.28
Jun-17	€ 10.70	€ 10.40	€ 10.53	€ 10.35	€ 11.94	€ 11.43
Jul-17	€ 8.81	€ 7.15	€ 11.42	€ 13.27	€ 9.98	€ 10.85
Aug-17	€ 8.00	€ 11.00	€ 14.58	€ 15.33	€ 12.35	€ 9.41
Sep-17	€ 12.90	€ 12.47	€ 14.32	€ 15.87	€ 15.24	€ 16.76

Continues from previous page						
Monthly FR=>GB	**PTR I**	**PTR II**	**DAM option**	**CfD last**	**CfD I**	**CfD II**
Oct-17	€ 6.12	€ 6.60	€ 1.56	€ 2.21	€ 6.28	€ 7.65
Nov-17	€ 3.70	€ 3.12	-€ 6.89	-€ 0.14	-€ 0.12	-€ 0.12
Dec-17	€ 3.47	€ 4.02	€ 5.40	-€ 0.14	-€ 0.12	-€ 0.13
Jan-18	€ 5.08	€ 4.21	€ 21.36	€ 3.41	€ 0.15	€ 2.61
Feb-18	€ 7.98	€ 9.01	€ 9.21	€ 8.24	€ 6.67	€ 8.71
Mar-18	€ 13.91	€ 12.30	€ 16.29	€ 16.11	€ 13.73	€ 12.17
Apr-18	€ 13.81	€ 15.37	€ 24.59	€ 18.59	€ 15.90	€ 17.29
May-18	€ 18.87		€ 26.28	€ 28.64	€ 21.56	€ 23.88
Jun-18	€ 17.03	€ 16.51	€ 19.22	€ 19.19	€ 22.76	€ 23.05
Jul-18	€ 15.39	€ 13.94	€ 12.68	€ 12.05	€ 15.98	€ 15.98
Aug-18	€ 15.17	€ 15.38	€ 9.20	€ 53.50	€ 18.13	€ 16.14
Sep-18	€ 10.17	€ 10.28	€ 12.38	€ 10.38	€ 13.50	€ 14.33
Oct-18	€ 8.63	€ 6.78	€ 7.24	€ 7.25	€ 8.89	€ 6.94
Nov-18	€ 5.88	€ 5.77	€ 2.44	€ 3.98	€ 1.72	€ 1.77
Dec-18	€ 7.20	€ 7.38	€ 14.94	€ 9.66	€ 6.27	€ 7.42

Table 3.A1. Comparison of PTRs, DAM options and CfDs (IFA, 2015-18).

In Table 3.A1, CfD last is the last day's closing price for GB – FR contracts, and CfD I and II align with the auction dates for the PTRs. PTRs have the advantage of being options not obligations while CfDs can be retraded repeatedly. Auctions are normally considered to aggregate information better than continuous trading at any moment, but the latter can take account of more information as it unfolds.

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

Table 3.A2. Monthly Auctions FR or NL to GB and DAM averages [GB-FR/NL]+. Note: [GB-NL]+ and DAM option mean the positive price differences, Max(DAMGB-DAMFR,0), lagged average over 28 days or 672 hours.

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

Table 3.A3. Quarterly and annual 2015 auctions FR/NL to GB and DAM averages [GB-FR/NL]+. Auction I* for BritNed is average of previous 8 auctions, ratio is last DAM auction. Missing values denote unavailable results.

Table 3.A3 similarly shows the quarterly auctions and the annual auctions (two for IFA, 9 for BritNed), and both tables show the ratio of the latest (and presumably most accurate) auction price to the outturn.

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

Table 3.A4. Auction and DAM option results 2016.

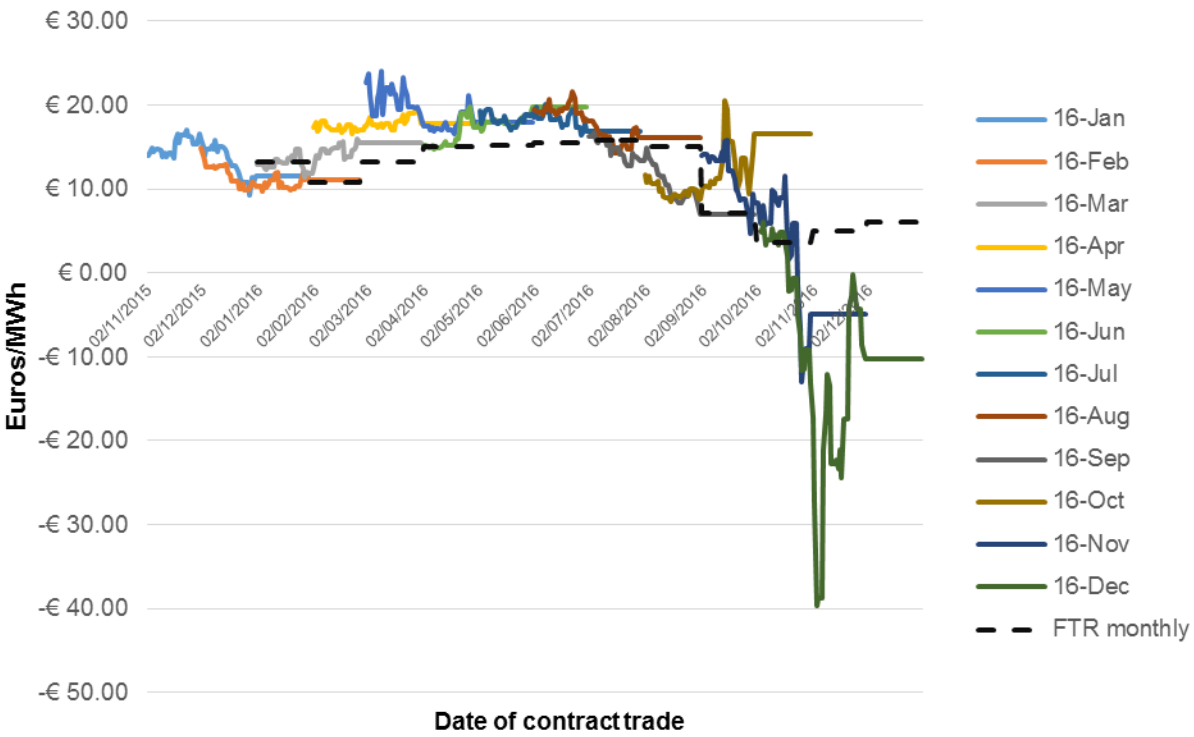


Figure 3.A1. Comparison between hedging across IFA using local power exchanges and PTRs month. Source: Bloomberg and ENTSO-E.

Appendix 3.2. ENTSO-E Data Description[103].

1 Day-ahead prices

For every market time unit the day-ahead prices in each bidding zone (Currency/MWh).

Note: In case of implicit allocation, Gate closure time of the day-ahead market shall be understood as the output time of the matching algorithms.

Primary owner of the data: Power Exchanges or TSOs

2 Total scheduled commercial exchanges

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

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

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

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

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

3 Cross Border Physical flow

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

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

4 Total Nominated Capacity

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

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

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

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

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

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

The value published for the intra-day time horizon consists of nominations from the following allocations: annual, quarterly, monthly, weekly, daily and intra-day.

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

Primary owner of the data: Transmission Capacity Allocator / TSO

5 Daily Flow Based Implicit Allocations - Congestion Income
In case of implicit allocations, for every market time unit the net positions of each bidding zone (MW) and the congestion income (in Currency) per border between bidding zones. The information shall be published no later than one hour after each capacity allocation.

Detailed description:

In case of implicit allocations:

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

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

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

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

9.2 Appendix 4 (Chapter 4)

Appendix 4.A1: Figures

Figure 4.A1 shows the average daily load curves for GB, France, and the Netherlands during 2015-2018, at Coordinated Universal Time (UTC). To facilitate comparison, we standardise each curve by dividing its hourly loads by its maximum load.

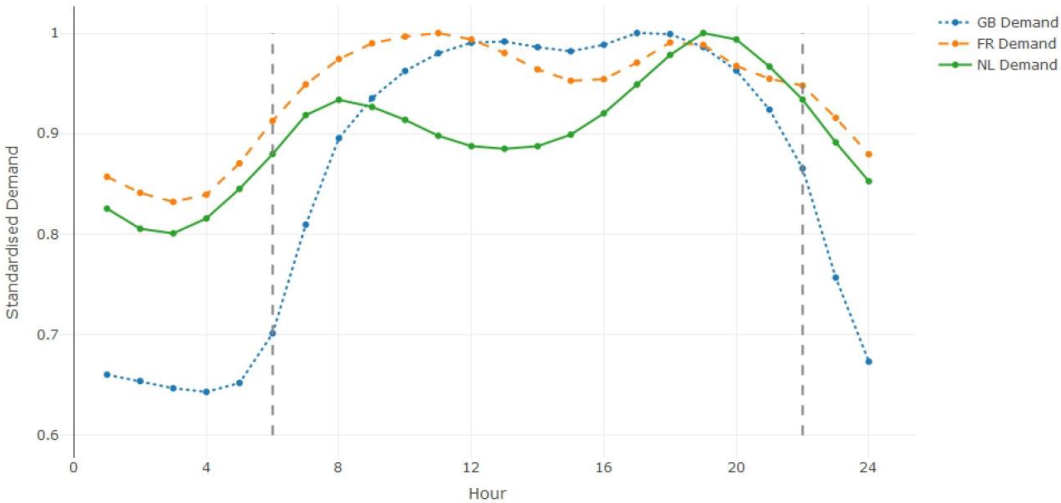


Figure 4.A1. Standardised Daily Average Load Curves, 2015-2018, UTC.

Figure 4.A2 plots an electricity market with a convex supply curve, where during off-peak periods during which excess exports shift demand from ND_0^{OFF} to ND_1^{OFF}, the spot price decreases by only a small amount.

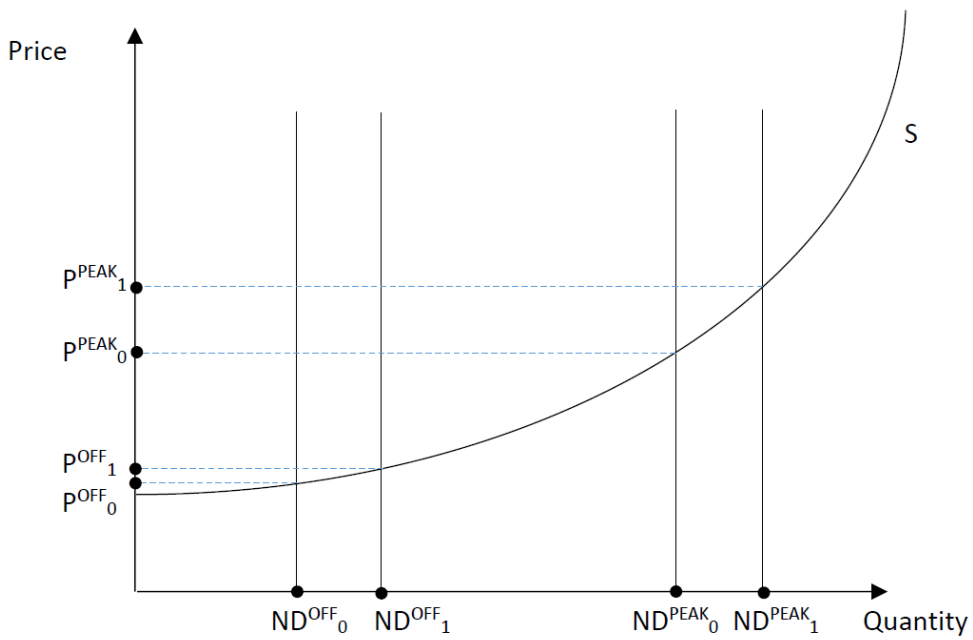


Figure 4.A2. A Market with a Convex Supply Curve.

The price differential duration schedule (PDDS) curves for IFA and BritNed, with and without the CPS, are shown in Figures 4.A3 and 4.A4. These use unadjusted price differentials,[104] so the IFA price differentials cluster around instead of at zero.

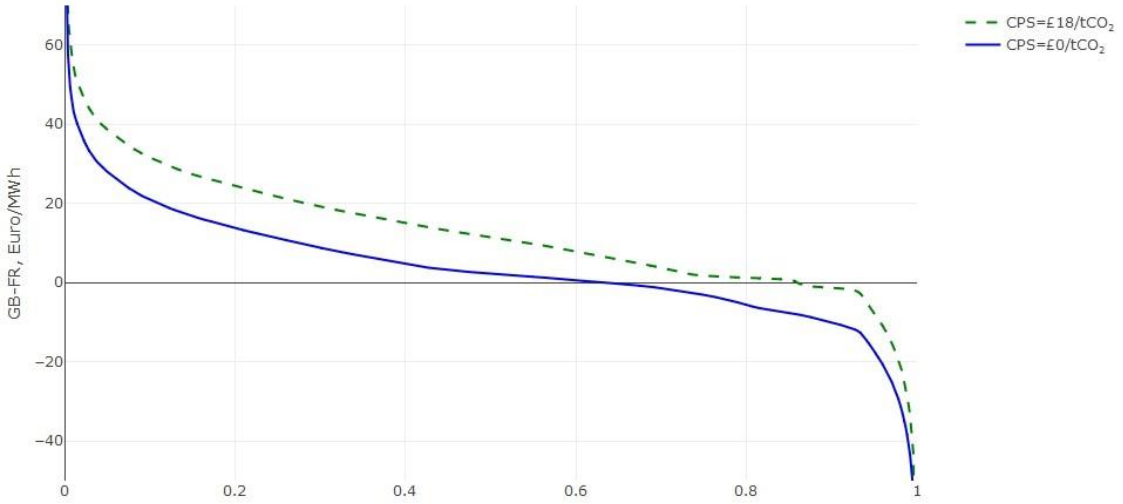


Figure 4.A3. The DS Curves for IFA with Different CPS, April 2015 - December 2018.

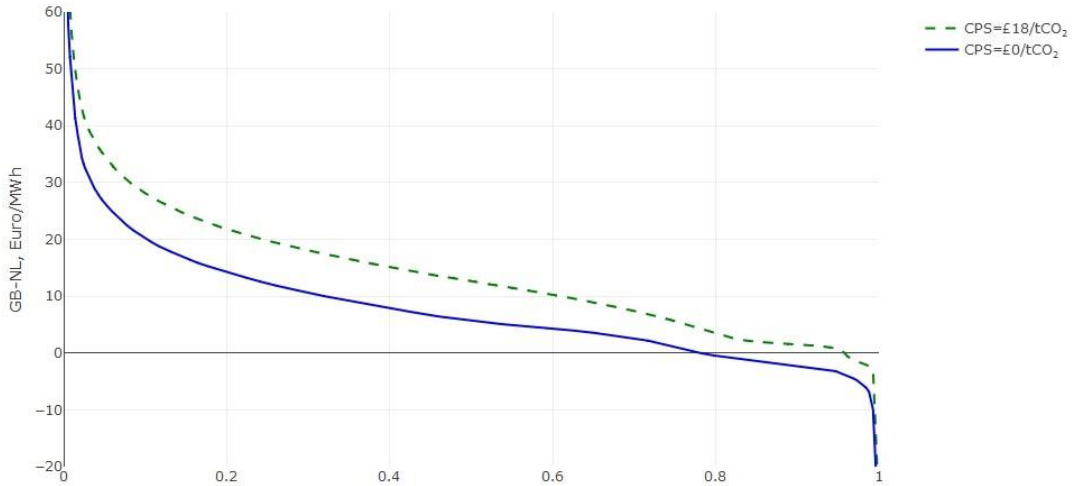


Figure 4.A4. The DS Curves for BritNed with Different CPS, April 2015 - December 2018.

[104] Unadjusted for losses. Seehttps://www.nationalgrideso.com/sites/eso/files/documents/Border Specific Annex IFA Interconnector 0.pdfandhttp://ifa1interconnector.com/media/1022/ifa-loss-factor.pdf

Appendix 4.A2: Tables

Table 4.A1 presents summary statistics for day-ahead market (DAM) prices for GB, France, and the Netherlands. The hourly data is aggregated by periods (peak and off-peak) of the day, and the statistics presented are for the daily averaged peak and off-peak prices for each market.

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

Table 4.A1. Summary Statistics, Day-ahead Markets, 2015-2018.

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

Table 4.A2. ADF Tests for DAM Prices (in €/MWh), Lags=7.

Table 4.A4 shows the M-GARCH results for other covariates included in the regression. We also test whether the impact of NTC on the price differential is independent with the CPS. We assume the coefficients for NTC are (linear and quadratic) functions of the CPS, and likelihood ratio (LR) tests do not reject the null hypothesis that the impact is independent with the CPS.

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

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

Table 4.A3. M-GARCH Results: Mean Equations (Cont'd).

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

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

Table 4.A4. M-GARCH Results: Conditional Variance Equations (Cont'd).

A.3 Cost-benefit analysis: an extension

Figure 4.A5 shows another case when the CPS alters the interconnector flow, where GB was initially exporting at partial capacity, LM, and the prices of the two markets are integrated at $P_1^{GB} = P_1^{FR}$. Without the interconnector the GB price would be PGB . The market surplus is again the producer (GB) surplus plus the consumer (FR) surplus, HIJ, and there is zero congestion income.

The CPS shifts the GB supply curve upward from S_0^{GB} to S_C^{GB} , and that switches GB from being a net exporter to a net importer. Similar to the case in Figure 4.4, the deadweight loss is the triangle HEG, which can be calculated as the half of the product of the swing of the interconnector flow, KL, and its impact on the cross-border price differential, $(P_C^{FR} - P_1^{FR}) + (P_1^{GB} - PP_C^{GB})$, or EG. Hence, EG/AG is the CPS pass-through rate.

The loss in carbon tax revenue is again AG×KL, and the congestion income under the CPS is ABCE, half of which goes to France.

The final case where the CPS changes interconnector flows is shown as Figure 4.A6. Without the CPS, GB was initially exporting at full capacity, KL, and the market clearing price was P_1^{GB} for GB and PFR for France. The market surplus is the green area HFG+ABC and the congestion income is the red rectangular BCFH.

The CPS shifts the GB supply curve from S_0^{GB} to S_C^{GB} . While still exporting, the amount GB exported has been reduced to KM. Consequently, the deadweight loss caused by the CPS is the shaded area BIQ+HJR, or half of the change in the interconnector flow, ML, multiplied

by the change in the price differential (due to the change in the interconnector flow), IQ+JR. The CPS PT ratio in this case is (IQ+JR)/EG.

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

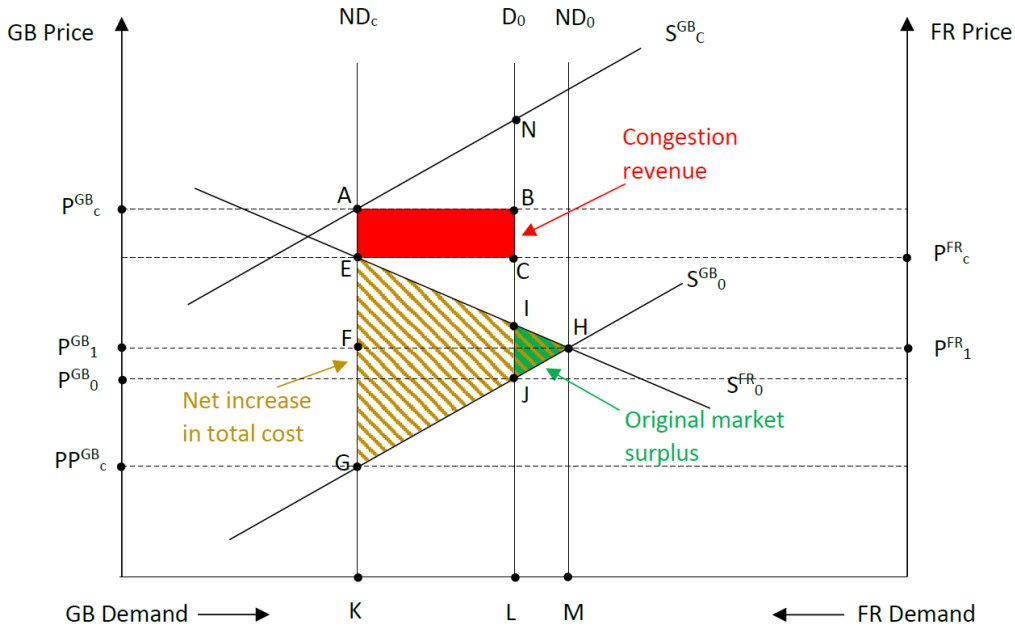


Figure 4.A5. Impact of CPS on Imports and Surpluses, GB from Exporting to Importing.

A.4 Trading in the intra-day and balancing market

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

Differences between the day-ahead scheduled commercial exchange and the actual physical flows are due to intra-day and balancing market trading. Newbery *et al*. (2019a) find that GB would rather reduce its day-ahead import from IFA in early morning hours (00:00-07:00) because the cost of ramping fossil plants down and then up could be higher than the intra-day cost of reducing its imports, which provide a flexible and cheaper alternative. We find similar results for BritNed by comparing the hourly averaged flows between the simulated day-ahead commercial exchange and the actual physical flow, as demonstrated by Figure 4.A7.[105]

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

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

about half that for IFA, namely €4 million (3%) for 2015-2016, €8 million (6%) for 2016-2017, and €8 million (7%) for 2017-2018.

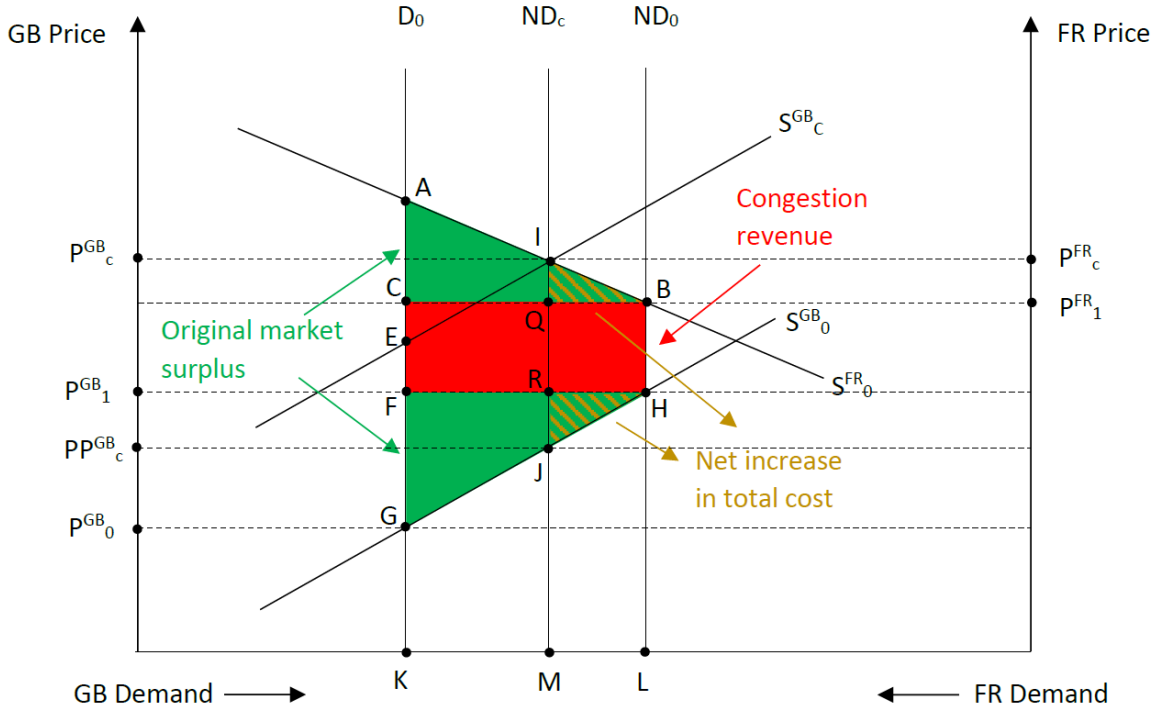


Figure 4.A6. Impact of CPS on Imports and Surpluses, GB Exports from Full to Partial Capacity.

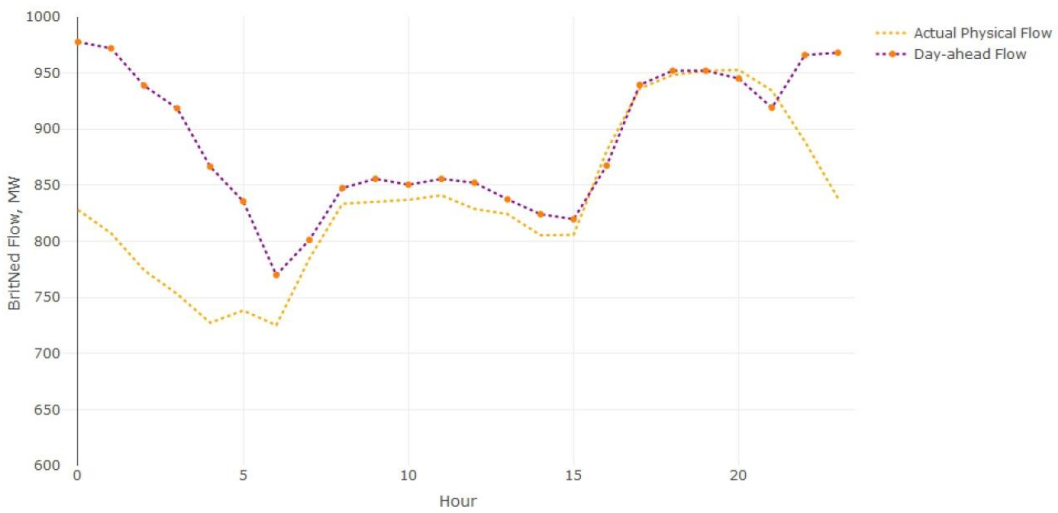


Figure 4.A7. Day-ahead v.s. Actual BritNed Commercial Exchange, 2015-2018.

9.3 Appendix 5 (Chapter 5)

Appendix 5.1: Estimating welfare gains

Two approaches have been used to estimate welfare gains. For historic interconnector performance, a series of metrics examining different aspects of welfare and trading efficiency have been developed, which are functions of market prices and interconnector flows (e.g. ACER, 2012; EU Commission, 2010-Q3). Since this approach cannot be used to estimate future welfare gains from interconnectors, the second approach is to use complex electricity system models to generate scenarios of flows and prices (e.g. Pöyry, 2012; Redpoint, 2013; ENTSO-E, 2014; EU Commission, 2015; and Aurora, 2016). Assumptions about the underlying electricity system vary widely between studies. Moreover, most models assume coupled markets, perfect foresight, and day-ahead plant dispatch, so account for neither demand uncertainty, trader behaviour, nor intra-day and balancing markets.

Appendix 5.2: Price-based metrics and flow-based metrics

Appendix 5.2.1: Price-based metrics

Interconnectors promote price convergence as traders buy and sell electricity until expected prices equalise. Coupling markets and increasing interconnection capacity can increase price convergence (Zachmann, 2008). Price convergence can be measured by simply inspecting the mean (or median) price differential between zones.

Price differentials. In 2017, price convergence varied greatly across Europe. The average absolute day-ahead price differential ranged from less than 0.5 €/MWh on the borders between Estonia and Finland, Portugal and Spain, and between Latvia and Lithuania, to more than 10 €/MWh between the Germany/Austria/Luxembourg bidding zone and five of its neighbouring countries, and on all British borders (likely due to GB's Carbon Price Floor). Large price differentials indicate that increasing cross-zonal interconnection capacity would reduce overall electricity system costs (ACER, 2015; 2017). In the absence of interconnection transmission limits, one would expect prices in all zones to converge in a competitive single market (Castagneto Gissey *et al.*, 2014).

Various econometric methods have been used to analyse electricity spot price convergence (De Vany and Walls, 1999; Robinson, 2007; Zachmann, 2008). Using principal component analysis, Zachmann (2008) rejects the overall market integration hypothesis except for certain pairs of European markets. Robinson (2007) employs B-convergence and co-integration tests, suggesting that convergence occurred for most European markets. Bunn and Gianfreda (2010) showed increased market integration for France, UK, Netherlands, Germany, and Spain. Integration was found not to increase with geographical proximity but with capacity of the interconnector. Kalantzis and Milonas (2010) found both interconnection and geographical distance playing a critical role in price dispersion.

Based on correlation and co-integration analyses, Boisseleau (2004) did not detect convergence among wholesale prices. Armstrong and Galli (2005) found convergence among wholesale price differentials in France, Germany, Netherlands and Spain from 2002 to 2004. Using fractional co-integration analysis, Houllier and de Menezes (2013) showed long memory for price shocks and co-integration to be present only for a few markets, including Germany, France and Netherlands. These studies considered integration between pairs of prices, whilst Castagneto Gissey *et al.* (2014) accounted for a whole system of prices, finding integration to be low but increasing over time and reflecting regulatory integration.

Appendix 5.2.2: Flow-based metrics

Flow-based metrics are imperfect as they do not consider price differentials and hence the value of inefficient flows.

Indexed annual aggregation of hourly NTC values. Changes in cross-zonal Net Transfer Capacity (NTC) offered to the market for trade are analysed by ACER (2012) for the period 2008–2012, representing a very simple measure of interconnector use. They estimate it for 23 EU borders, finding a 9% increase to be a 'modest [but] positive trend'. Despite this, the recorded values are meaningful only if extra capacities are not utilised inefficiently, so the measure fails to directly consider the efficiency of interconnector use.[106]

Capacity utilisation ratio.[107] The ratio of the number of hours when capacity was used to the number of hours when it was available. ACER (2012) compared the intra-day capacity utilisation to that in the day-ahead timeframe, concluding that intra-day capacity utilisation was relatively low.[108] In addition, the authors concluded that implicit allocation (as under market coupling) was less inefficient than explicit (or other) allocation methods.[109]

Absolute sum of net nominations per year. This measure indicates the level of available cross-zonal market capacity and is considered for *intra-day* markets by ACER (2018). They show that, in absolute terms, aggregated cross-zonal allocations nominated across the European network tripled between 2010 and 2017. While this metric is useful to understand the level of capacity nominated on the interconnector, it does not indicate whether this capacity is used inefficiently since it does not involve prices.

[106] See ACER (2012), Section 3.2.2.
[107] These are considered for price differentials greater than €1/MWh, which are viewed as significant by ACER (2016, 2017).
[108] For 2017, 50% utilisation rate in intra-day vs 86% utilisation rate in day-ahead.
[109] See ACER (2012), Section 5.2.

Appendix 5.3: Charts of Flow vs Price differential

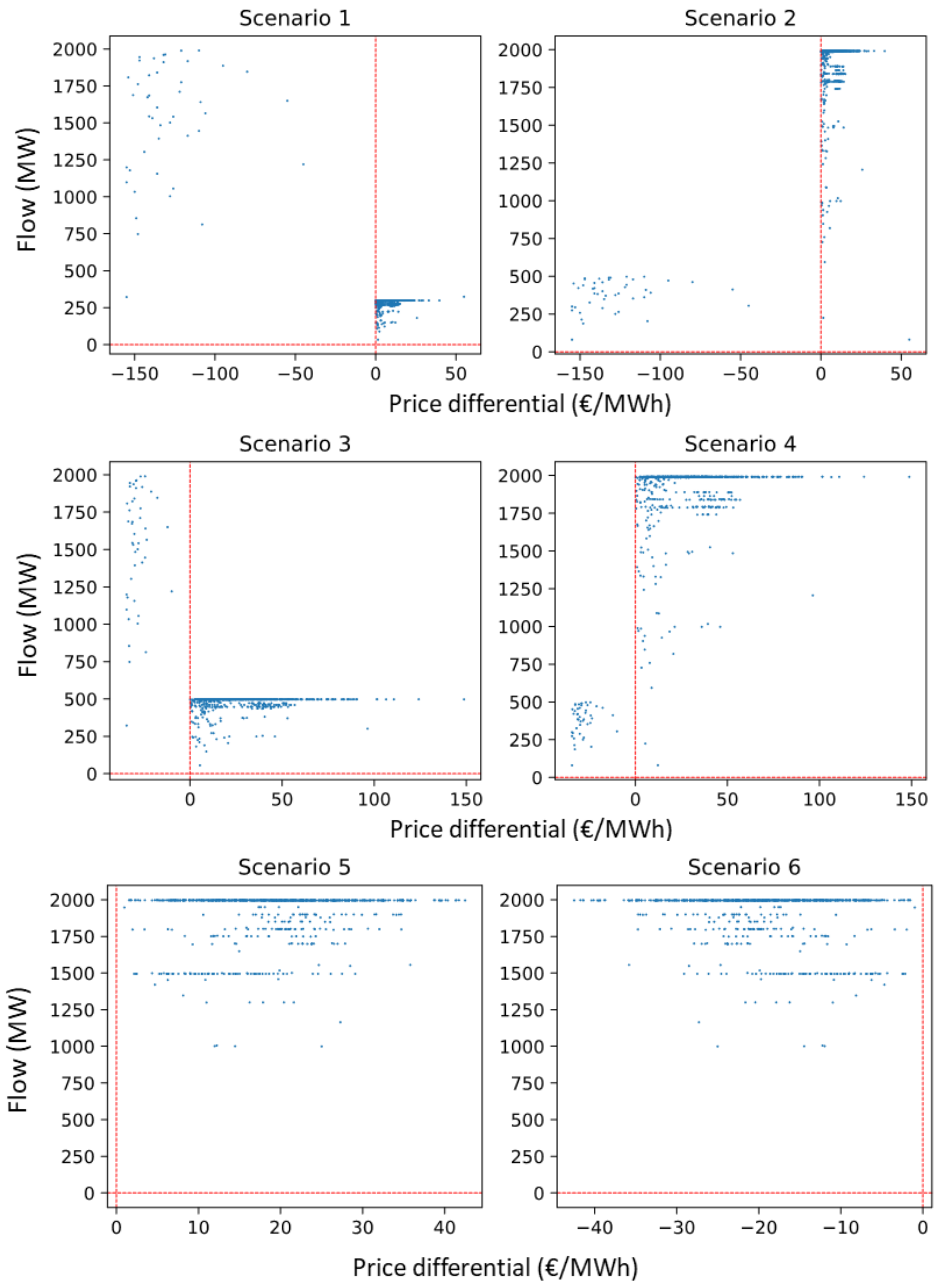


Figure 5.A1(a). Scatterplots of the stress data for Scenarios 1–6.

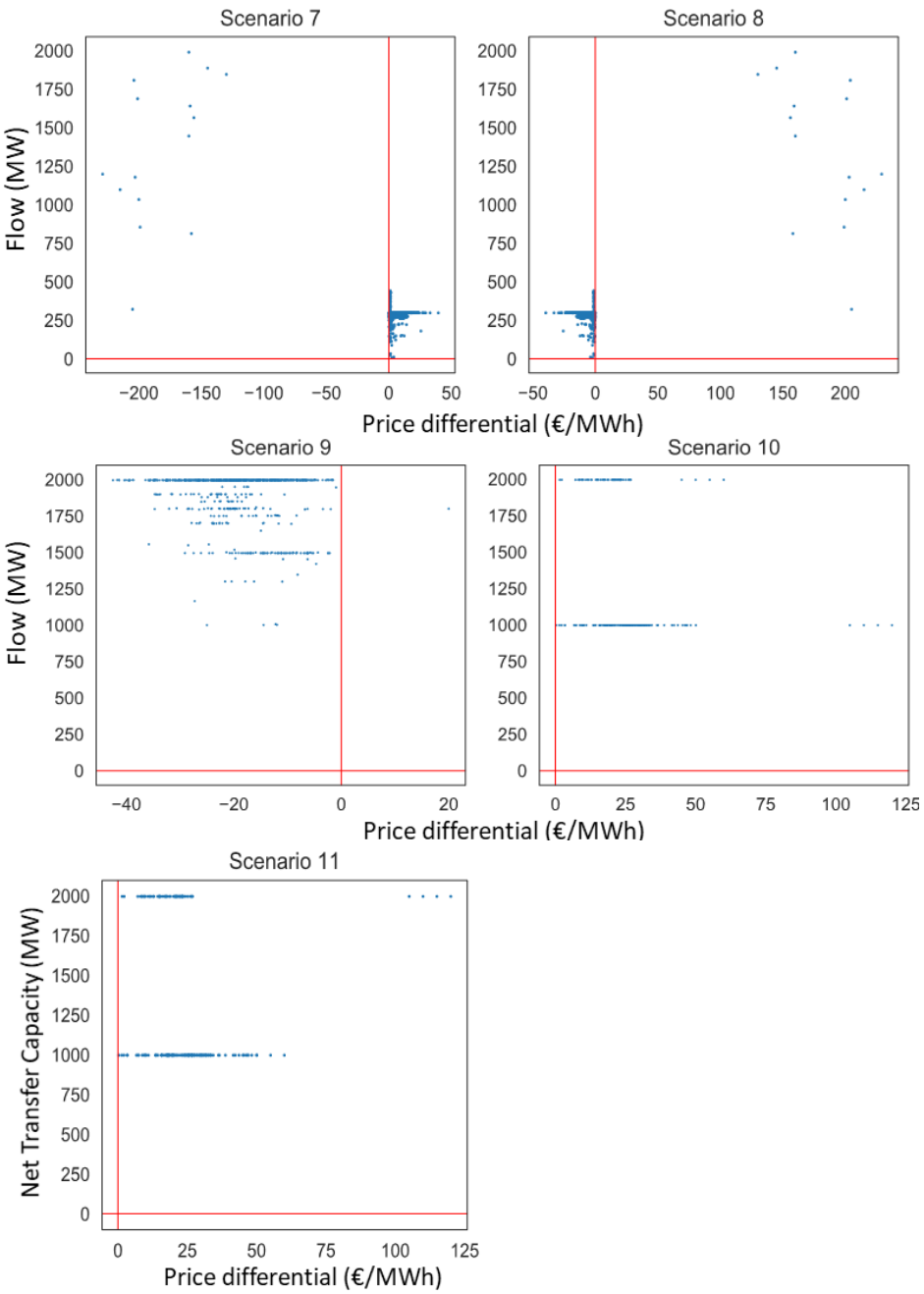


Figure 5.A1(b). Scatterplots of the stress data for scenarios 7–11.

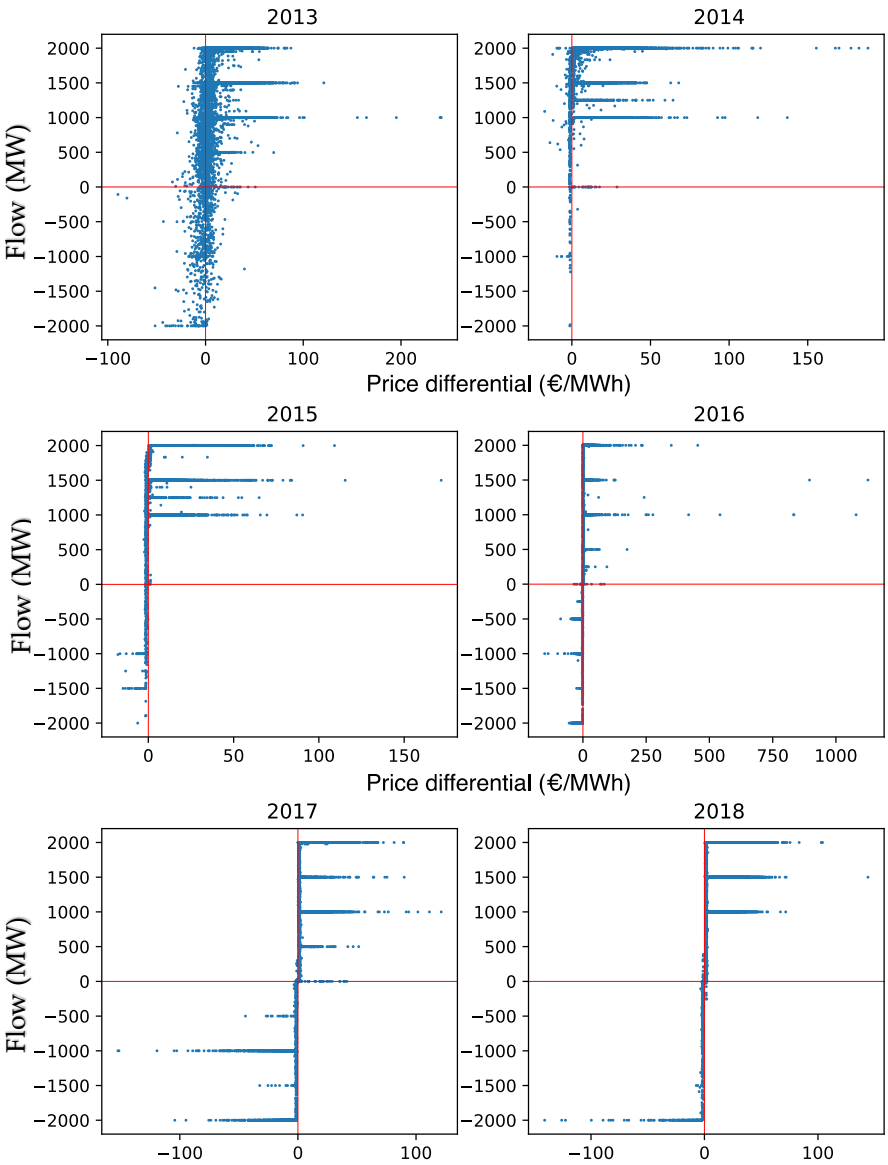


Figure 5.A2. Plot of GB-FR Day-ahead price vs FR->GB RTE flow. Day-ahead NWE coupling went live on 04-02-2014.

Appendix 5.4: Measures of social welfare

Interconnectors increase welfare by reducing the overall cost of the interconnected electricity systems, creating consumer surplus for importers and producer surplus for exporters. Since social welfare is challenging to calculate, the metrics presented in the paper are used instead to estimate commercial interconnector efficiency, which is a good proxy for social welfare if markets are competitive and externalities properly priced. Some studies have calculated social welfare metrics directly, particularly for examining the potential impacts of deploying new interconnectors which may change prices (usually assuming efficient markets).

Models are used to estimate the change in social welfare due to adding an interconnector to connect two systems. For example, the UK electricity regulator, Ofgem, analysed welfare

changes by estimating the consumer and producer surplus[110] changes for the proposed ElecLink interconnector between Great Britain and France.[111] This requires an electricity system model to examine the counterfactual situation in which the interconnector has/has not been deployed (depending on whether the study is taking place before or after deployment). Since models include numerous assumptions and simplifications compared with real markets, it is difficult to compare studies.

Social welfare should include all external costs of CO_2 emissions and other pollutants, as well as correcting for market power (or basing calculations on costs rather than prices). Mansur and White (2012) consider the impacts of moving from bilateral trading to simultaneous market dispatch and clearing. By comparing monthly prices before and after a bilaterally cleared zone joined the Pennsylvania-Jersey-Maryland (PJM) nodally-priced market area, they estimated reductions in price differentials and welfare gains, finding potential incremental gains of $3.6m/GW. Ott (2010) used a similar approach and found that the total benefit of efficiently pricing PJM was $2.2bn/yr. De Jong *et al.* (2007) simulated four EU countries, finding welfare effects of flow-based market coupling at about €200m/yr. Meeus (2011) studied historical data relating to the 600 MW Kontek cable linking Denmark to Germany over various coupling initiatives and found imperfect coupling with 5% UFAPDs even after coupling took place, with welfare gains of €10m/yr. The SEM Committee (2011) estimated the social costs of not coupling the two interconnectors between Great Britain and the Single Electricity Market (SEM) of the island of Ireland for 2010. The estimated social welfare gains from coupling were €30m/yr based on an average import capacity of 930 MW, or €32m/GWyr.

The relatively modest welfare and efficiency benefits in these studies may be underestimated because the models are too simplistic to account for all of the transmission failures that coupling may relieve, and because they are calibrated based on previous generation portfolios with lower renewable generation (and so less congestion) than seen at present (Newbery *et al.*, 2016). National Grid (2015) estimated that sharing reserves over interconnectors could reduce capacity needs by nearly 3 GW, which could be worth €15m/GWyr. These findings led to regulators requiring coupling of electricity markets in Europe, until 85% of the European power consumption was coupled in 2015 (Geske *et al.*, 2018).

Appendix 5.5: Methodological appendix: Metrics

Appendix 5.5.1: Derivation of the new metrics

For any hour h of the day, in any two regions A and B, electricity flows of magnitude $\tilde{f}_h(MW)$ move across an interconnector in the direction $A \rightarrow B$ at a price differential (€/MWh)

[110] Consumer surplus is the difference between the highest price a retailer is willing to pay and the actual market price of electricity. Producer surplus is the difference between the electricity market price and the lowest price a generator would be willing to accept.

[111] https://www.ofgem.gov.uk/ofgem-publications/84685/appendix2-londoneconomicseleclinkreviewsummary.pdf

$D_{BA(h)} := P_{B(h)} - P_{A(h)}$. Ideally,[112] arbitrageurs import electricity into market B from market A when prices are lower in A and conversely, import into A from B ($B \rightarrow A$) when prices are lower in B. Efficient trading behaviour in idealised conditions give rise to the step-curve[113] (S-curve) pattern in Left diagram of Figure 5.A3.

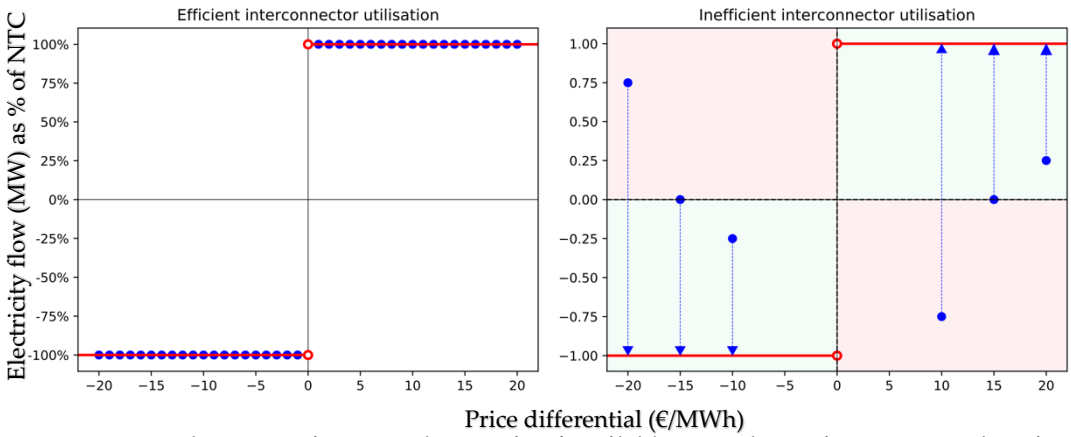


Figure 5.A3. Here, the S-curve is reported as a ratio of available to used capacity, as opposed to Figure 5.1, for simplicity. LEFT: S-curve (in red) of the efficient utilisation pattern by interconnector arbitrageurs (blue points) across markets A, B. x-axis denotes the price differential $D_{BA(h)}$. The y-axis denotes the electricity flow as a percentage of NTC in direction A→B. RIGHT: Red and blue areas denote adverse and favourable flow quadrants; the blue line is the distance of the inefficient flow from the S-curve.

The distance of non-maximal flows from the S-curve in the right-hand side diagram of Figure A1 is then

distance(adverse-flows) + distance(favourable-flows) + distance(no-flows)

which we define as

$$I_4 = \left(\frac{N^-}{N}\right)\left(\frac{1}{N^-}\right)\sum_h^{N^-}\frac{(1+|f_h^-|)}{2} + \left(\frac{N^+}{N}\right)\left(\frac{1}{N^+}\right)\sum_h^{N^+}\frac{(1-|f_h^+|)}{2} + \left(\frac{N^0}{N}\right)\left(\frac{1}{N^0}\right)\sum_h^{N^0}\frac{(1-|f_h^0|)}{2}$$

where

$$\begin{aligned} N &= N^- + N^+ + N^0 \\ F &= f^- + f^+ + f^0 \\ |y| &= absolute\ value\ of\ y \\ f_h &= \frac{\tilde{f}_h}{NTC_h} \end{aligned}$$

with the superscripts '-' , '+', *0*[114], denoting adverse-flow,[115] favourable-flow and no-flow,[116] respectively. *NTC* denotes net transfer capacity and $\tilde{f}_h$ the hourly flow.

[112] Synchronicity of market gate closures and capacity allocation, perfect information set, no physical constrains such as ramping, loop-flows, etc.
[113] Under the idealised conditions, arbitrageurs should not import or export when the market prices in region A and B are equilibrated and there are positive losses across the link: Hence the $D_{BA} = 0$ discontinuity.
[114] By definition $f_h^0 = 0$.

Appendix 5.5.2: SCUWED as a limit for UIIU

When all flows are favourable and NTC is constant Equation (5.4) becomes

$$UIIU = \frac{1}{2}\left(\frac{1}{N}\sum_{h}^{N}\left(1-\left|\frac{\tilde{f}_h}{K}\right|\right)\right) = \frac{1}{2}\left(1-\frac{1}{N}\sum_{h}^{N}\left|\frac{\tilde{f}_h}{K}\right|\right) = \frac{1}{2}\left(1-\frac{\sum_h^N|\tilde{f}_h|}{\sum_h^N|K|}\right) = \frac{1}{2}(1-SCURED)$$

Appendix 5.5.3: Additional price-weighting schemes

Equation (5) adjusts to equation (4) by weighing the interconnector underutilisation by price differential weight according to w_h.

Other weightings schemes, such as

$$\begin{aligned} w_1 &= \frac{x_h^2}{\sum x_h^2} \\ w_2 &= \frac{e^{\beta x_h}}{\sum e^{\beta x_h}} \\ w_3 &= \frac{e^{\beta|x_h|}}{\sum e^{\beta|x_h|}} \end{aligned}$$

can be applied where the degree of convexity will determine the influence of price differential outliers on the computed metric. Note that surpluses and deadweight loss increase as the square of the price differential so w_1 may be a better welfare weight. Due to its linear nature, our choice of weighting scheme results in minimum bias from outliers. One could also[117] apply a scheme with symmetric emphasis on outliers via w_1 (or w_3 with $\beta = 0.05$), or with adverse flows asymmetrically penalised (w_2 with $\beta = -0.01$) as in Figure 5.A4 below.

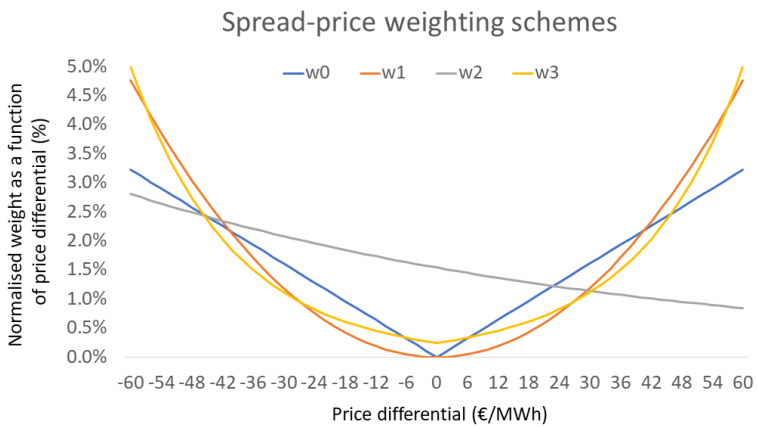


Figure 5.A4. Price differential weighting according to different weighting schemes. w0 is the price differential weighting applied in equation (5.5), w^1-w^3 as per Appendix 5.5.3. For w^2 and w^3, β = -0.01 and 0.05 respectively.

[115] Adverse flow is synonymous with flow against price differential (FAPD) and analogous with flows in the correct economic direction.

[116] A no-flow is the event of zero IC utilisation given that a non-zero price differential occurred.

[117] When dealing with underdetermined systems and optimisation.

Appendix 5.5.4 Data pre-processing

Pre-processing data can be helpful in deriving a meaningful price differential, or attempt to account for reverse flows, loss-factors, etc. This data reduction can lead to subjective choices of thresholds to filter out information to be (or not) included in analysis. In our analysis, we opted not to apply any filtering to the data. Applying a filter of €1 to the price differential, shows how the temporal evolution of the indices remain unchanged.

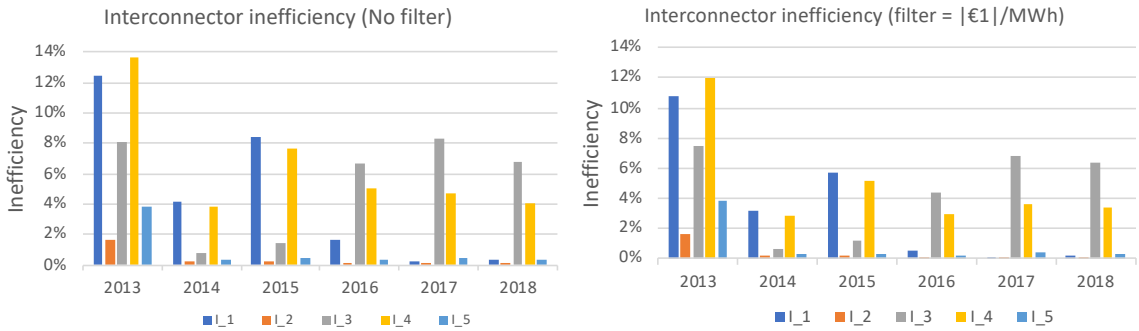


Figure 5.A5. Results of metrics by year (IFA). LEFT: Original series without a filter. RIGHT: Series with a filter of (absolute) €1/MWh below which price differentials are ignored for the analysis, as done in many ACER and EU Commission reports.

Appendix 5.5.5: UIIU and PWIIU by hour of the day

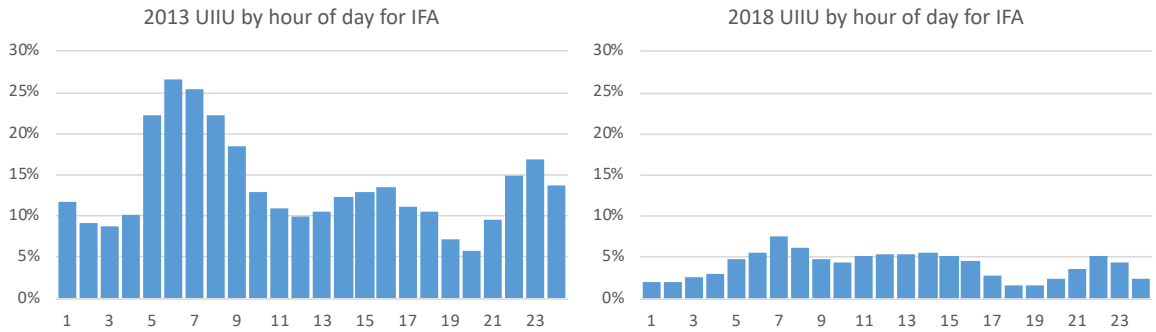


Figure 5.A6(a). Unweighted interconnector inefficient utilisation metric (UIIU) (%, y-axis) averaged by hour of the day (x-axis) for selected years, for the IFA interconnector.

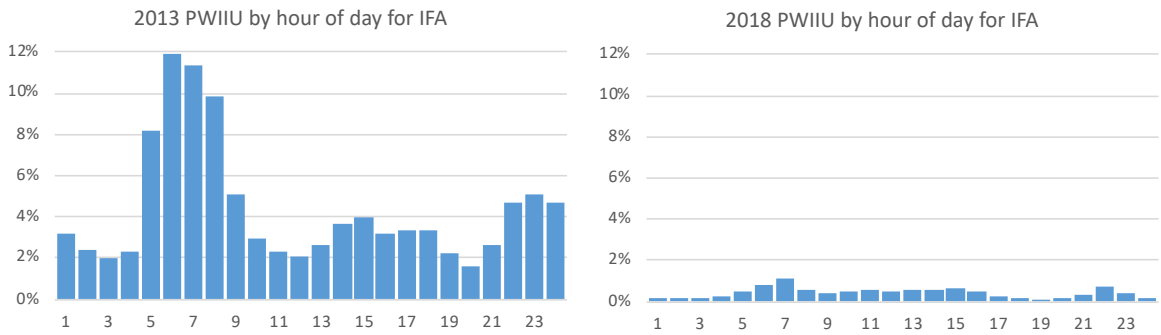


Figure 5.A6(b). Price-Weighted Interconnector Inefficient Utilisation (PWIIU) metric (%, y-axis) averaged by hour of the day (x-axis) for selected years, for the IFA interconnector.

Appendix 5.5.6: Worksheet prototype implementation of metrics

We provide a spreadsheet implementation of both indices here introduced, I_1 and I_5.

Date	hour	flow	NTC	gb -fr
01/01/2013	1	1500	1500	€ 24.30
01/01/2013	2	1500	1500	€ 28.54
01/01/2013	3	1500	1500	€ 23.42

Table 5.A1. Summary table of user input data.

Interconnector utilisation data is first provided in the format of Table 5.A2. Intermediate calculations in Table 5.A3 are performed with corresponding formulae provided in Table 5.A4.

flow_adj	year	month	y&m	flow/NTC	fpd	uD(S)	|gb_fr|	w_h(m)	w_h(y)	wD(S)_y	CR
1500	2013	1	2013-1	100%	1	0.00%	24.30	0.31%	0.02%	0.00%	€ 36,456
1500	2013	1	2013-1	100%	1	0.00%	28.54	0.37%	0.02%	0.00%	€ 42,817
1500	2013	1	2013-1	100%	1	0.00%	23.42	0.30%	0.02%	0.00%	€ 35,123

Table 5.A2. Intermediate calculations required for estimation of metrics i1 -- I5. flow_adj is used only in the calculation of SCUWED.

column	Formula
flow_adj	=ABS(IF(ABS([@flow])<=[@NTC],[@flow],SIGN([@flow])*[@NTC]))
year	=YEAR([@date])
month	=MONTH([@date])
y&m	=[@year]&[@month]
flow/NTC	=[@flow]/[@NTC]
fpd	=SIGN([@[gb-fr]]*[@flow])
uD(S)	=IF([@fpd]=-1,1,0) * (1+ABS([@[flow/NTC]]))/2 + IF([@fpd]=1,1,0) * (1-ABS([@[flow/NTC]]))/2 + IF([@fpd]=0,1,0) * (1/2)
|gb_fr|	=ABS([@[gb-fr]])
w_h(m)	=[@[|gb_fr|]]/VLOOKUP([@[y&m]],**sum_abs_spreads_months**,2,FALSE)
wD(S)_m	=[@[w_h(m)]]*[@[uD(S)]]
w_h(y)	=[@[|gb_fr|]]/VLOOKUP([@year],**sum_abs_spreads_years**,2,FALSE)
wD(S)_y	=[@[w_h(y)]]*[@[uD(S)]]
CR	=[@[gb-fr]]*[@flow]

Table 5.A3. Formulae for intermediate calculations in Table 5.A7. Boldface denotes named ranges described in Tables 5.A5 and 5.A6.

The spreadsheet '*TableB*' object is the union of Tables 5.A1 and 5.A2 and is used in the final calculation of the annual and monthly results of Table 5.A8 and 5.A9 with their respective formulae provided in Tables 5.A6 and 5.A7.

Y&M	M_sum(| x |)	Formula
2013-1	7735	=SUMIFS(TableB[|gb_fr|],TableB[year],"=2013", TableB[month],"=1")
2013-2	5506	=SUMIFS(TableB[|gb_fr|],TableB[year],"=2013",

		TableB[month],"=2")
2013-3	10922	=SUMIFS(TableB[|gb_fr|],TableB[year],"=2013", TableB[month],"=3")

Table 5.A4. Detail of 'sum_abs_spreads_months' named range. The named range is given by the first two columns. The third column is the formula for column two (M_sum|x|).

Year	Y_sum(|x|)	Formula
2013	152536	= SUMIF(TableB[year],"=2013",TableB[|gb_fr|])
2014	155106	= SUMIF(TableB[year],"=2014",TableB[|gb_fr|])
2015	153612	= SUMIF(TableB[year],"=2015",TableB[|gb_fr|])

Table 5.A5. Detail of 'sum_abs_spreads_years' named range. The named range is given by the first two columns. The third column is the formula for column two (Y_sum|x|).

column	Formula
N	=COUNTIF(TableB[year],"=2013")
N+	=COUNTIFS(TableB[year],"=2013",TableB[fpd],"1")
N-	=COUNTIFS(TableB[year],"=2013",TableB[fpd],"-1")
N0	=COUNTIFS(TableB[year],"=2013",TableB[fpd],"0")
I1	=[@[N-]]/[@N]
I2	=ABS(SUMIFS(TableB[CR],TableB[year],"=2013", TableB[fpd],"=-1"))/(SUMIFS(TableB[CR],TableB[year],"=2013", TableB[fpd],"=1") + ABS(SUMIFS(TableB[CR],TableB[year],"=2013", TableB[fpd],"=-1")))
I3	=1 - (SUMIFS(TableB[flow_adj],TableB[year],"=2013",TableB[fpd],"=1")/ SUMIFS(TableB[NTC],TableB[year], "=2013",TableB[fpd],"=1"))
I4	=SUMIFS(TableB[uD(S)],TableB[year],"=2013")/[@N]
I5	=(SUMIFS(TableB[wD(S)_y],TableB[year],"=2013",TableB[fpd],"=1")+SUMIFS(TableB[wD(S)_y],TableB[year],"=2013", TableB[fpd],"=-1")+SUMIFS(TableB[wD(S)_y],TableB[year],"=2013", TableB[fpd],"=0"))

Table 5.A6. Formulae corresponding to columns in Table 5.A4. The example provided is for calendar year 2013.

column	Formula
N	=COUNTIFS(TableB[year],"=2013", TableB[month],"=1")
N+	=COUNTIFS(TableB[year],"=2013", TableB[month],"=1",TableB[fpd],"1")

N-	=COUNTIFS(TableB[year],"=2013", TableB[month],"=1",TableB[fpd],"-1")
N0	=COUNTIFS(TableB[year],"=2013", TableB[month],"=1",TableB[fpd],"0")
I1	=COUNTIFS(TableB[year],"=2013", TableB[month],"=1",TableB[fpd],"-1")/COUNTIFS(TableB[year],"=2013", TableB[month],"=1")
I2	=ABS(SUMIFS(TableB[CR],TableB[year],"=2013", TableB[month],"=1",TableB[fpd],"=-1"))/(SUMIFS(TableB[CR],TableB[year],"=2013", TableB[month],"=1",TableB[fpd],"=1") + ABS(SUMIFS(TableB[CR],TableB[year],"=2013", TableB[month],"=1",TableB[fpd],"=-1")))
I3	=1-(SUMIFS(TableB[flow_adj],TableB[year],"=2013", TableB[month],"=1",TableB[fpd],"=1")/SUMIFS(TableB[NTC],TableB[year],"=2013", TableB[month],"=1",TableB[fpd],"=1"))
I4	=(SUMIFS(TableB[uD(S)],TableB[year],"=2013", TableB[month],"=1")/AK2)
I5	=(SUMIFS(TableB[wD(S)_m],TableB[year],"=2013", TableB[month],"=1",TableB[fpd],"=1")+SUMIFS(TableB[wD(S)_m],TableB[year],"=2013", TableB[month],"=1",TableB[fpd],"=-1")+SUMIFS(TableB[wD(S)_m],TableB[year],"=2013", TableB[month],"=1",TableB[fpd],"=0"))

Table 5.A7. Formulae corresponding to the columns in Table 5.A4. The example provided is for the month of January 2013.

Appendix 5.6: Monthly Historical Dataset Results

Appendix 5.6.1: IFA

Year	Month	N	N+	N-	N0	*UFAPD*	*WFAPD*	*SCUWED*	*UIIU*	*PWIIU*
2013	1	744	567	177	0	23.8%	5.2%	15.5%	24.7%	10.2%
2013	2	672	482	190	0	28.3%	8.9%	23.8%	29.9%	16.6%
2013	3	744	608	136	0	18.3%	4.0%	14.8%	21.2%	9.0%
2013	4	721	604	117	0	16.2%	3.6%	8.6%	16.2%	6.7%
2013	5	744	717	27	0	3.6%	0.3%	0.4%	3.3%	0.4%
2013	6	720	713	7	0	1.0%	0.1%	0.5%	1.2%	0.2%
2013	7	744	726	18	0	2.4%	0.2%	0.8%	2.6%	0.4%
2013	8	744	721	23	0	3.1%	0.3%	1.7%	3.4%	0.8%
2013	9	698	648	50	0	7.2%	0.8%	5.0%	8.1%	1.7%
2013	10	744	644	100	0	13.4%	2.2%	9.1%	15.0%	4.6%
2013	11	720	623	97	0	13.5%	1.9%	13.4%	16.2%	4.7%
2013	12	744	596	148	0	19.9%	3.9%	17.8%	22.6%	7.6%
2014	1	744	698	46	0	6.2%	0.7%	2.3%	6.5%	1.1%
2014	2	672	649	23	0	3.4%	0.6%	1.7%	3.6%	0.9%
2014	3	720	705	15	0	2.1%	0.1%	0.8%	2.1%	0.2%
2014	4	720	702	18	0	2.5%	0.1%	0.8%	2.4%	0.2%
2014	5	744	734	10	0	1.3%	0.0%	0.4%	1.2%	0.1%
2014	6	720	702	18	0	2.5%	0.1%	0.5%	2.2%	0.1%
2014	7	744	744	0	0	0.0%	0.0%	0.0%	0.0%	0.0%
2014	8	744	740	4	0	0.5%	0.0%	0.0%	0.5%	0.0%
2014	9	720	704	16	0	2.2%	0.1%	0.2%	2.1%	0.1%
2014	10	744	669	74	1	9.9%	0.5%	0.6%	8.8%	0.6%
2014	11	720	703	17	0	2.4%	0.1%	0.3%	2.2%	0.1%
2014	12	744	621	120	3	16.1%	0.7%	2.1%	13.7%	1.1%
2015	1	744	597	147	0	19.8%	1.4%	2.2%	17.6%	1.7%
2015	2	672	513	156	3	23.2%	1.9%	7.1%	21.3%	2.9%
2015	3	744	657	86	0	11.6%	0.6%	2.0%	10.7%	0.9%
2015	4	720	701	19	0	2.6%	0.1%	0.5%	2.5%	0.1%
2015	5	744	739	5	0	0.7%	0.0%	0.2%	0.6%	0.0%
2015	6	720	717	3	0	0.4%	0.0%	0.0%	0.4%	0.0%
2015	7	744	722	22	0	3.0%	0.1%	0.1%	2.6%	0.1%
2015	8	744	743	1	0	0.1%	0.0%	0.0%	0.1%	0.0%
2015	9	720	712	8	0	1.1%	0.0%	0.1%	1.1%	0.1%
2015	10	744	631	112	0	15.1%	0.8%	3.1%	13.2%	1.3%
2015	11	720	632	88	0	12.2%	0.6%	3.0%	11.8%	0.9%
2015	12	744	655	89	0	12.0%	0.4%	2.6%	10.6%	0.7%
2016	1	744	689	55	0	7.4%	0.2%	3.9%	7.5%	0.4%
2016	2	696	675	21	0	3.0%	0.1%	0.3%	2.7%	0.1%
2016	3	744	734	10	0	1.3%	0.1%	0.1%	1.2%	0.1%
2016	4	720	718	2	0	0.3%	0.0%	0.4%	0.4%	0.0%
2016	5	744	744	0	0	0.0%	0.0%	0.3%	0.1%	0.0%
2016	6	720	720	0	0	0.0%	0.0%	0.0%	0.0%	0.0%
2016	7	744	744	0	0	0.0%	0.0%	0.8%	0.4%	0.0%
2016	8	744	737	7	0	0.9%	0.0%	5.9%	3.4%	0.3%
2016	9	720	692	28	0	3.9%	0.0%	24.7%	13.4%	0.7%
2016	10	725	704	8	13	1.1%	0.0%	20.9%	10.3%	0.9%
2016	11	720	698	4	18	0.6%	0.0%	23.1%	11.3%	1.3%
2016	12	744	718	6	20	0.8%	0.0%	18.2%	10.5%	1.3%

Table 5.A8. Monthly historical dataset results for years 2013 to 2016 for all indices UFAPD–PWIIU (IFA).

Appendix 5.6.2: BritNed

Year	Month	N	N+	N-	N0	*UFAPD*	*WFAPD*	*SCUWED*	*UIIU*	*PWIIU*
2013	1	745	593	150	2	20.1%	3.5%	21.4%	22.7%	9.8%
2013	2	670	584	86	0	12.8%	1.4%	16.1%	16.2%	5.2%
2013	3	744	630	113	1	15.2%	3.1%	7.6%	15.2%	5.1%
2013	4	720	528	191	1	26.5%	6.8%	24.4%	27.7%	15.7%
2013	5	744	563	181	0	24.3%	4.4%	18.0%	23.7%	11.1%
2013	6	708	585	123	0	17.4%	2.6%	16.8%	19.0%	8.2%
2013	7	744	666	78	0	10.5%	1.8%	7.5%	11.6%	3.7%
2013	8	744	662	82	0	11.0%	2.0%	8.9%	12.6%	4.5%
2013	9	603	525	74	4	12.3%	1.6%	14.4%	15.1%	5.1%
2013	10	744	616	123	5	16.5%	2.2%	14.2%	18.2%	5.8%
2013	11	720	635	85	0	11.8%	1.6%	10.9%	13.4%	4.6%
2013	12	744	635	108	1	14.5%	2.2%	13.5%	16.4%	6.1%
2014	1	694	634	60	0	8.6%	1.0%	4.3%	8.8%	2.2%
2014	2	0	0	0	0	N/A	N/A	N/A	N/A	N/A
2014	3	434	418	16	0	3.7%	0.2%	2.2%	4.0%	0.5%
2014	4	720	696	24	0	3.3%	0.2%	2.9%	4.1%	0.5%
2014	5	743	704	39	0	5.2%	0.4%	2.1%	5.1%	0.7%
2014	6	720	678	42	0	5.8%	0.5%	2.1%	5.7%	0.8%
2014	7	744	725	19	0	2.6%	0.2%	0.9%	2.5%	0.3%
2014	8	744	713	31	0	4.2%	0.3%	1.7%	4.1%	0.6%
2014	9	559	527	32	0	5.7%	0.5%	2.1%	5.8%	0.7%
2014	10	744	703	41	0	5.5%	0.4%	1.4%	5.4%	0.5%
2014	11	720	687	33	0	4.6%	0.2%	1.4%	4.6%	0.4%
2014	12	720	608	112	0	15.6%	1.2%	2.8%	14.0%	1.7%
2015	1	744	664	80	0	10.8%	0.6%	7.4%	11.5%	1.3%
2015	2	672	617	55	0	8.2%	0.4%	8.6%	10.0%	1.1%
2015	3	744	708	36	0	4.8%	0.2%	5.7%	6.3%	0.6%
2015	4	720	710	10	0	1.4%	0.1%	2.4%	2.2%	0.2%
2015	5	679	642	36	1	5.3%	0.2%	3.1%	5.6%	0.3%
2015	6	720	693	27	0	3.8%	0.2%	3.8%	4.8%	0.4%
2015	7	744	714	30	0	4.0%	0.2%	3.2%	4.5%	0.4%
2015	8	744	726	18	0	2.4%	0.1%	2.3%	3.0%	0.3%
2015	9	655	643	12	0	1.8%	0.1%	4.0%	3.5%	0.3%
2015	10	744	691	51	2	6.9%	0.3%	5.5%	7.9%	0.7%
2015	11	720	654	66	0	9.2%	0.4%	4.6%	8.9%	0.7%
2015	12	744	660	84	0	11.3%	0.3%	5.3%	10.8%	0.6%
2016	1	744	704	40	0	5.4%	0.2%	1.8%	4.8%	0.4%
2016	2	696	693	3	0	0.4%	0.0%	1.2%	0.9%	0.0%
2016	3	744	740	4	0	0.5%	0.0%	1.0%	1.0%	0.1%
2016	4	720	718	2	0	0.3%	0.0%	1.6%	1.0%	0.0%
2016	5	680	678	2	0	0.3%	0.0%	3.7%	2.1%	0.1%
2016	6	720	716	4	0	0.6%	0.0%	7.2%	4.0%	0.4%
2016	7	744	740	4	0	0.5%	0.0%	9.6%	5.2%	0.6%
2016	8	744	742	2	0	0.3%	0.0%	4.1%	2.2%	0.2%
2016	9	678	650	28	0	4.1%	0.2%	11.9%	8.9%	0.6%
2016	10	744	729	15	0	2.0%	0.1%	9.8%	6.2%	0.4%
2016	11	720	699	21	0	2.9%	0.1%	4.5%	4.5%	0.3%
2016	12	744	684	60	0	8.1%	0.4%	8.2%	9.7%	1.1%

Table 5.A9. Monthly historical dataset results for years 2013 to 2016 for all indices UFAPD–PWIIU (BritNed).

Appendix 5.7: Methodological appendix: simulation

We use a simulation-based method to derive the expected cross-border price differentials between GB and France and the Netherlands, and flows for IFA and BritNed, had the interconnectors not been coupled. Our simulation assumes a cross-border market where, after the foreign price has been set, risk-averse traders have to forecast the GB price to make trading decisions, and any forecast errors would result in either an inefficient use of interconnectors or Flows Against Price Differences (FAPDs). We then compare the simulated price differentials and flows with actual data under market coupling to assess the impact of coupling the cross-border electricity markets. The simulation model is simplified from Geske *et al.* (2018). Our analysis in this section only focuses on the day-ahead market, where the GB electricity market is (up to end 2019) fully coupled with France and the Netherlands.

Before the 2014 market coupling came into force, the day-ahead (DA) market closed in France before it did in GB. This meant that traders had to predict GB prices, thereby facing uncertainty. Based on Geske *et al.* (2019), we assume that traders have a mean-variance utility function and, for simplicity, we assume the data is always collected from the import side (i.e. after accounting for transmission losses). Taking IFA as an example, we assume a single trader[118] who maximises her utility function, U_h, in each hour, h

$$\text{Max E}(U_h) = T\left(\text{E}\left(P_h^{GB}\right) - P_h^{FR}\right) - \frac{\lambda}{2}(T * C_{GB,h}^{''} * \sigma_{GB,D})^2,$$

where $\text{E}(U_h)$ is the expected utility of the trader, which is given by the difference between congestion revenue and a penalty term to evaluate the trader's level of uncertainty; T is GB's net import from France in GW; P_h^{GB} and P_h^{FR} are the GB and French DA electricity prices respectively in €/MWh; λ is the trader's discount factor towards price volatility; $C_{GB,h}^{'}$ is GB's aggregated marginal cost function and $C_{GB,h}^{''}$ is the marginal value of electricity sales; and $\sigma_{GB,D}$ is the standard error of traders' forecast of GB electricity demand.

Given the above, the utility maximisation problem (by equalising the first-order condition of $\text{E}(U_h)$ to zero) finds the optimal trading (net import for GB in GW) $\hat{T}$ as:

$$\hat{T}\left(\text{E}\left(P_h^{GB}\right), P_h^{FR}\right) = \begin{cases} Cap_h & Cap_h \leq \theta \\ \theta & 0 \leq \theta < Cap_h \\ 0 & \text{E}\left(P_h^{GB}\right) = P_h^{FR} \\ \theta & -Cap_h \leq \theta \leq 0 \\ -Cap_h & \theta \leq -Cap_h \end{cases}$$

$$\theta = \frac{\text{E}\left(P_h^{GB}\right) - P_h^{FR}}{\lambda \cdot (C_{GB,h}^{''}\sigma)^2} = \frac{\text{E}\left(P_h^{GB}\right) - P_h^{FR}}{\mu}$$

where θ denotes net import if there were no capacity constraint; and Cap_h denotes the net transfer capacity (NTC). The numerator of θ denotes the (expected) DA price differential

[118] For simplicity, we assume there is only one trader who participates in day-ahead cross-border electricity trading. We assume that the trader can bid on a maximum volume equivalent to the net transfer capacity, then it is equivalent to assuming that there are n equivalent traders in the market.

between GB and France, while the denominator, $\mu = \lambda \cdot (C''_{GB,h}\sigma)^2$, is a function of unknown parameters. It is worth noticing that instead of separately identifying λ, σ, and $C''_{GB,h}$, we only need to identify μ to conduct our simulation. Intuitively, a greater expected price differential indicates greater potential for imports, therefore θ is positively correlated with the expected DA price differential.

With forecast errors, θ can be expressed as

$$\theta = \frac{P_h^{GB} + \varepsilon_h^{GB} - P_h^{FR}}{\lambda(C''_{GB,h}\sigma)^2}$$

where $\varepsilon_h^{GB} \sim \mathrm{N}(0, \sigma_{GB,P}^2)$.

We aim to identify parameters μ and $\sigma_{GB,P}^2$ such that the simulated[119] DA scheduled commercial exchange for IFA (and BritNed) in 2013 (when the markets are uncoupled) is reasonably close to the actual IFA (BritNed) day-ahead scheduled commercial exchange in 2013, by comparing proposed metrics of trading inefficiency in this paper.

Once the parameter values for IFA and BritNed have been identified, we can use the parameters and the observed DA prices for both markets to simulate the uncoupled IFA and BritNed flows and price differentials during the examined electricity years (2014-2019). We then compare the simulated uncoupled counterfactuals with the actual coupled flow and price differentials from the same period.

We measure the degree of interconnector inefficiency before and after market coupling using the metrics *PWIIU*, *UIUU*, *FAPD*, *WFAPD*, and *SCUWED*.

Appendix 5.8: Value of market coupling

Appendix 5.8.1: Trading in uncoupled markets

In uncoupled markets, traders must separately buy electricity in one market, sell in another market, and buy and nominate interconnector capacity from the first market to the second market. Efficient day-ahead nominations require traders to accurately predict the magnitude and direction of the day-ahead auction price differentials. In practice, this can be quite challenging: prior to market coupling, day-ahead scheduled flow was frequently suboptimal, or even in the wrong direction (ACER, 2012).

Where day-ahead scheduled flow proves economically suboptimal, it is possible for traders to correct it in the intra-day markets. This requires them to buy and nominate intra-day capacity, and either to buy and sell in the different markets, or to accept exposure to the balancing mechanism. In practice, there are generally limited liquidity and significant transaction costs in intra-day markets, and a general reluctance to exposure to volatile prices

[119] Note that the day-ahead scheduled commercial exchange in 2013 and 2014 are from ENTSO-E, but the data for 2015-2018 are from simulation as ENSTSO-E no longer provide this data since 2015.

in the balancing mechanism.[120] As a result, interconnector flow will often only be adjusted in the intra-day market where there is a large enough movement in the price differential, or for operational reasons such as an unexpected change in generation or demand. After Brexit, it is expected that GB will be uncoupled in the day-ahead market but coupled in the intra-day market.

Appendix 5.8.2: Trading in coupled markets

Day-ahead coupling obviates the need to predict day-ahead price differentials. Instead, the EUPHEMIA algorithm will ensure that the DA flow is optimised, based on bids and offers in the two markets and interconnector constraints. The interconnector may be constrained, in which case there is a price differential between the two markets, and capacity holders receive a financial settlement based on the price differential (adjusted for any losses applied by the interconnector operator). Alternatively, the interconnector may be unconstrained, in which case no settlement is made.

As a result of this ability to release interconnector capacity for optimised settlement based on the day-ahead auction, traders are less likely to manually nominate their interconnector capacity. Even if the interconnector capacity is being held as a hedge for offsetting physical positions in the two markets, it may still make sense for the capacity and the two physical positions to be closed out financially in the day-ahead market.

Appendix 5.8.3: Simulation results for IFA

The measures of the inefficiency of the simulated flows (denoted as "Simulated flow 2013, BritNed" with different values of parameters $\sigma_{GB,P}$ and μ are reported in Table 5.A10 and are compared with those of the actual uncoupled IFA flow in 2013, denoted as the "Actual flow 2013, IFA".

We gradually increase the values of $\sigma_{GB,P}$ and μ until the measures of inefficiency (I_1 to I_5) are reasonably close to the actual measures of inefficiency in 2013. As it is shown in Table 5.A10, when $\sigma_{GB,P}$ =7 and μ= 5, by comparing I_1 to I_5, the simulated flow and the actual flow are similarly inefficient. Therefore, when simulating the uncoupled flow for IFA for 2014-2019, we set $\sigma_{GB,P}$ =7 and μ= 5.

[120] The SEM Committee (2019) found 92% of trades took place in or prior to the day-ahead market. The remaining 8% of trades took place in declining quantities in the three intraday and continuous markets, falling from 4% in the first intraday market to less than 0.5% in the continuous market.

			I_1	I_2	I_3	I_4	I_5
Actual flow 2013, IFA			12.4%	1.7%	8.1%	13.6%	3.8%
Simulated flow 2013, BritNed	**Parameter Values**						
	$\sigma_{GB,P}$	$\lambda(C''_{GB,h}\sigma)^2$					
	4	4	8.7%	0.6%	8.5%	10.4%	1.7%
	5	4	9.7%	0.8%	8.3%	11.2%	2.1%
	5	5	9.6%	0.7%	10.6%	11.5%	2.4%
	6	5	11.3%	1.1%	9.8%	12.9%	2.9%
	7	***5***	***12.8%***	***1.6%***	***9.6%***	***14.1%***	***3.6%***

Table 5.A10. Day-ahead actual and simulated flows for IFA in 2013

We then simulate scenarios where trading over IFA occurs without market coupling during 2014-2019 and compare them with the actual data under market coupling, in terms of net imports into GB, congestion revenue, infra-marginal surplus, and trading inefficiency. The results are reported in Table 5.A11.

Among our main findings, based on annual averages, coupling caused the price differential between GB and France to fall by €0.26/MWh, net imports into GB to increase by 2.26 TWh (or by 21.5%), congestion Income increased by €13.71 million (or by 6%), and infra-marginal surplus increased by €3.3 million (or by 25%, or about 1.4% of uncoupled congestion revenue).

	Price Difference (€/MWh)			Net GB Imports (TWh)		
Electricity year	**Coupled**	**Uncoupled**	**Δ**	**Coupled**	**Uncoupled**	**Δ**
2014-2015	15.83	16.20	-0.37	15.20	12.34	2.86
2015-2016	18.76	19.00	-0.24	15.52	13.53	1.99
2016-2017	8.54	8.72	-0.18	8.17	6.65	1.52
2017-2018	10.49	10.75	-0.26	11.32	8.96	2.36
2018-2019	13.76	14.05	-0.29	13.66	11.06	2.60
Average	13.48	13.74	-0.26	12.77	10.51	2.26
2016-2017 w/o CPS	-0.45	-0.54	0.09	-0.13	0.55	-0.68
2017-2018 w/o CPS	2.59	2.42	0.17	0.54	1.81	-1.27
Average w/o CPS	1.07	0.94	0.13	0.20	1.18	-0.98
	Congestion Income (million €)			**Infra-marginal Surplus (million €)**		
2014-2015	256.84	244.53	12.31	17.17	13.84	3.33
2015-2016	318.28	307.42	10.86	18.35	16.03	2.32
2016-2017	197.33	184.13	13.20	12.48	9.56	2.92
2017-2018	210.82	194.16	16.66	16.78	12.77	4.01
2018-2019	234.06	218.54	15.52	16.81	13.10	3.71
Average	243.47	229.76	13.71	16.32	13.06	3.26
2016-2017 w/o CPS	154.34	136.85	17.49	12.11	7.72	4.39
2017-2018 w/o CPS	150.91	130.59	20.32	15.88	10.20	5.68
Average w/o CPS	152.62	133.72	18.91	13.99	8.96	5.03

Table 5.A11. Price differential (€/MWh), net GB Imports (TWh), congestion income (million €), and infra-marginal surplus (million €) for coupled and uncoupled trading over IFA, by year.

We compare the inefficiency of the coupled and uncoupled markets using a range of trading inefficiency metrics, with results shown in Table 5.A12. It is straightforward to see that market coupling reduced the inefficiency of cross-border trading. On average, during 2014-2019, the share of FAPDs fell from 12.1% to a negligible 2.8%, and the Weighted FAPDs (*WFAPDs*) from 1.6% to only 0.1%. *PWIIU*, *UIIU*, and *SCUWED* also considerably decreased.

Electricity year	Market condition	Metrics				
		UFAPD	*WFAPD*	*SCUWED*	*UIIU*	*PWIIU*
2014-2015	**Coupled**	7.6%	0.3%	1.2%	6.8%	0.5%
	Uncoupled	11.7%	1.3%	9.0%	12.9%	3.7%
2015-2016	**Coupled**	4.9%	0.1%	1.0%	4.6%	0.2%
	Uncoupled	8.3%	0.8%	7.0%	9.8%	2.6%
2016-2017	**Coupled**	0.7%	0.0%	8.6%	5.6%	0.6%
	Uncoupled	15.0%	2.0%	12.4%	17.0%	4.9%
2017-2018	**Coupled**	0.2%	0.0%	7.4%	4.2%	0.6%
	Uncoupled	13.4%	2.1%	14.4%	16.2%	5.9%
2018-2019	**Coupled**	0.4%	0.0%	7.4%	4.5%	0.4%
	Uncoupled	12.3%	1.8%	13.4%	14.7%	4.8%
Average 2014-2019	**Coupled**	2.8%	0.1%	5.1%	5.1%	0.5%
	Uncoupled	12.1%	1.6%	11.2%	14.1%	4.4%
2016-2017 w/o CPS	**Coupled**	3.1%	0.1%	4.8%	6.7%	0.7%
	Uncoupled	17.2%	3.5%	17.4%	19.3%	7.0%
2017-2018 w/o CPS	**Coupled**	5.3%	0.2%	4.5%	9.5%	1.3%
	Uncoupled	20.6%	4.3%	19.7%	23.2%	10.3%

Table 5.A12. IFA trading inefficiency with and without market coupling, by year. Key: I_1, I_2, I_3, I_4, I_5 are *UFAPD* (or *FAPD*), *WFAPD*, *SCUWED*, *UIIU*, and *PWIIU*, respectively.

We also simulated the cases where the GB Carbon Price Support (CPS) is removed, finding that when GB and French day-ahead prices are reasonably close (in 2016-2018), and when markets are uncoupled, all metrics of inefficiency would be significantly higher than the cases where the CPS has been implemented and the GB price is much greater than the French price. This is because when prices are closer, it is much more difficult to accurately forecast the sign of price differentials between two markets and the direction of flows, resulting in greater trading inefficiency.

The impact of market coupling was also tested by relaxing the assumption of a British CPS and comparing differences between the coupled and uncoupled market. Average differences in price differential (€/MWh), net imports (TWh), congestion income (million €), and infra-marginal surplus (million €) for coupled and uncoupled trading over IFA between 2016-2018, are reported in the last three rows of Table 5.A11. By removing the CPS, GB prices in 2016-2018 would have been reasonably close to the French price, and so the net imports are close to zero (although this is made up of considerable imports and exports, hence the substantial congestion income). Without the CPS, the impact of uncoupling on congestion income and infra-marginal surplus are slightly higher (by €5.2 million/yr and €1.3m./yr respectively) than in cases with the CPS.

Appendix 5.8.4: Simulation results for BritNed

BritNed has an interconnector capacity of 1 GW, or half the 2 GW of IFA. Therefore, the change in flows due to market coupling (relative to uncoupling) may have lower impacts on the BritNed price differential, net imports, and private and social benefit, compared to IFA. As performed for the case of IFA, we begin by comparing the simulated 2013 BritNed DA

scheduled commercial exchange with the actual value (from ENTSO-E[121]), with results shown in Table 5.A13.

			I_1	I_2	I_3	I_4	I_5
Actual flow 2013, BritNed			15.9%	2.7%	14.2%	18.2%	7.5%
Simulated flow 2013, BritNed	**Parameter Values**						
	$\sigma_{GB,P}$	$\lambda(C''_{GB,h}\sigma)^2$					
	3	4	14.7%	2.2%	9.2%	16.4%	4.8%
	3	5	14.6%	1.9%	11.4%	16.9%	4.9%
	4	5	17.2%	3.2%	11.5%	19.1%	6.7%
	4	***6***	***16.7%***	***2.8%***	***13.7%***	***19.1%***	***6.8%***
	4	7	15.7%	2.2%	16.6%	19.2%	6.9%

Table 5.A13. Day-ahead actual and simulated flows for BritNed.

When $\sigma_{GB,P} = 4$ and $\mu = 6$, the "simulated flow 2013, BriNed" is reasonably close to the "actual flow 2013, BritNed". We therefore assume the values for parameters to simulate the uncoupled BritNed flow during 2015-2018[122] is $\sigma_{GB,P} = 4$ and $\mu = 6$.

We then assess the impact of market coupling on BritNed, with results shown in Table 5.A14. Similarly to IFA, market coupling facilitates price convergence, raises congestion revenue and infra-marginal surplus. GB also imports more thanks to market coupling because the GB price is almost always higher than the Dutch price during the period 2015-2018.

On average, market coupling reduced the price differential between GB and the Netherlands by €0.09/MWh (by 0.6%), increased net imports into GB by 0.42 TWh/yr (by 5.6%), raised congestion income by €1.9 m/yr (by 1.5%), and boosted infra-marginal surplus by €0.9 m/yr (by 0.7% of uncoupled congestion revenue). The impact of market coupling on BritNed is smaller than that on IFA. This is not only because of BritNed's lower capacity, but also because the price differential between GB and the Netherlands is much larger than that between GB and France, meaning there is less uncertainty on the sign of the GB-NL price differential. Uncoupling would therefore result in a lower share of FAPDs and an increase in congestion income and infra-marginal surplus.

Similarly to IFA, the removal of asymmetric carbon taxes would result in spot price convergence between GB and the Netherlands. As a result, uncoupling the interconnector would have higher impact on both congestion income and infra-marginal surplus.

[121] For BritNed, ENTSO-E only provides the day-ahead scheduled commercial exchange before 2015, or after 2018.

[122] As there is no freely available public data for the BritNed day-ahead scheduled commercial exchange, we use the simulated data from Guo *et al.* (2019).

	Price Difference (€/MWh)			Net Import (TWh)		
Electricity year	**Coupled**	**Uncoupled**	**Δ**	**Coupled**	**Uncoupled**	**Δ**
2015-2016	17.00	17.09	-0.09	8.27	7.89	0.38
2016-2017	15.78	15.88	-0.10	7.85	7.41	0.43
2017-2018	12.82	12.91	-0.09	7.71	7.28	0.43
Average	15.20	15.29	-0.09	7.94	7.53	0.42
2016-2017 w/o CPS	9.60	9.38	0.22	4.26	4.70	-0.45
2017-2018 w/o CPS	7.36	7.08	0.28	3.68	4.32	-0.64
	Congestion Income (million €)			**Infra-marginal Surplus (million €)**		
Electricity year	**Coupled**	**Uncoupled**	**Δ**	**Coupled**	**Uncoupled**	**Δ**
2015-2016	148.02	146.77	1.24	11.65	11.01	0.63
2016-2017	137.10	135.03	2.07	11.17	10.25	0.92
2017-2018	112.62	110.12	2.51	10.73	9.62	1.11
Average	132.58	130.64	1.94	11.18	10.30	0.89
2016-2017 w/o CPS	87.76	84.08	3.69	9.23	7.25	1.98
2017-2018 w/o CPS	68.89	65.52	3.37	8.53	6.39	2.13

Table 5.A14. Price differential (€/MWh), net GB Imports (TWh), congestion income (million €), and infra-marginal surplus (million €) for coupled and uncoupled trading over BritNed, by year.

Table A15 compares trading inefficiency for BritNed, with and without market coupling, for electricity years 2015-2018. Again, uncoupling increases trading inefficiency. *UFAPD* (*WFAPD*) increased from 3.1% (0.1%) to 7.9% (0.7%), while *SCUWED*, *UIUU*, and *PWIIU* also show substantial increases.

It is also worth mentioning that the metrics (I_1-I_5) shown in Table 5.A15 based on uncoupled markets during 2015-2018 are smaller than the metrics in 2013 (Table 5.A10), where BritNed was also uncoupled. This is because in 2013, the average GB-NL price differential is €7.11/MWh, which was much lower than in 2015-2018, shown in Table 5.A15 (on average €15.2/MWh under market coupling). This confirms our earlier finding where if prices are closer, uncoupling would have a more negative impact on trading inefficiency.

Electricity Years	Market Condition	Metrics				
		UFAPD	*WFAPD*	*SCUWED*	*UIIU*	*PWIIU*
2015-2016	**Coupled**	4.4%	0.2%	3.1%	5.4%	1.1%
	Uncoupled	6.1%	0.4%	3.6%	7.0%	1.7%
2016-2017	**Coupled**	2.5%	0.1%	6.6%	5.6%	2.7%
	Uncoupled	8.1%	0.6%	5.9%	9.5%	3.7%
2017-2018	**Coupled**	2.3%	0.1%	9.0%	6.7%	1.6%
	Uncoupled	9.6%	1.0%	7.1%	11.4%	3.1%
Average 2015-2018	**Coupled**	3.1%	0.1%	6.2%	5.9%	1.8%
	Uncoupled	7.9%	0.7%	5.5%	9.3%	2.8%
2016-2017 w/o CPS	**Coupled**	0.9%	0.0%	8.9%	11.5%	5.2%
	Uncoupled	13.4%	2.0%	13.0%	16.5%	7.4%
2017-2018 w/o CPS	**Coupled**	1.3%	0.0%	10.9%	13.5%	4.4%
	Uncoupled	16.0%	2.6%	14.2%	18.7%	7.0%

Table 5.A15. BritNed trading inefficiency with and without market coupling, by year. Key: I_1, I_2, I_3, I_4, I_5 are *UFAPD* (or *FAPD*), *WFAPD*, *SCUWED*, *UIIU*, and *PWIIU*, respectively.

Without carbon tax asymmetries, the electricity prices between GB and the Netherlands would further converge. As a result, the impact of market uncoupling would be severe, resulting in much higher inefficiency.

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bartlett.ucl.ac.uk/energy bartlett.ucl.ac.uk/sustainable
@UCL_Energy
@UCL_ISR

Central House
14 Upper Woburn Place
London, WC1H 0NN
United Kingdom