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"The European Internal Energy Market's Worth to the UK"

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The European Internal Energy Market's Worth to the UK[+]

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Abstract

This article proposes a two-country model of electricity trade under peak-load pricing. We apply the model to France and the UK to assess the benefit to the UK of trade within the European internal energy market (IEM). Calibration and simulations of the model aimed at simulating bilateral trade in the market coupling process at electricity exchanges show the following. First, the occurrence of gains from trade for both countries is highly dependent on whether imported electricity affects the price in the local market and whether imports alleviate scarcity. Second, the main effect of importing electricity is a shift in welfare from domestic producers to domestic consumers of the importing country. Finally, the UK's membership in the IEM generates additional welfare for the UK of up to 900 M€ per year across a range of scenarios in which the number of on-peak periods are exogenously varied in a conservative way relative to the actual data.

Key words: Electricity, Market Coupling, Brexit, Calibration, Simulation.

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1. Introduction

What is the future of the trade relations between the United Kingdom (UK) and the European Union (EU)? What about the exchange of such an important commodity as electricity? More than three years after the fateful referendum that put Britain on its way out of the EU, many questions remain open while economists have a range of possible scenarios to study that seemed unthinkable just a few years before. The rollback of the integration between electricity markets in the UK and abroad is among them. Indeed, even though fundamental insights from industrial organization and regulatory economics largely apply to the electricity sector, the high degree to which this sector is still regulated and was historically shaped by mostly state-owned vertically-integrated monopolies, as well as issues of essential facilities, environmental externalities, and technology set this sector apart.

What are the benefits of linking up electricity markets and how can we quantify these benefits? What do gains from trade look like in electricity markets under peak-load pricing? In this article, we rely on a computational-analytical model to characterize short-term electricity market equilibria and perform an analysis with the aim of feeding the economic policy debate surrounding the UK's political stance on the EU. Using data on the UK and France, we calibrate the model and perform simulations with the objective of assessing how valuable membership in the internal energy market (IEM) is for the UK. In the context of Brexit, this issue is of great relevance for related trade negotiations, as each side will demand economically sound proof for demands raised by its counterpart.

The events that this study refers to evolved rapidly while this research was undertaken. Less than three weeks after the official request to leave the EU had been sent to Brussels by the British Government, Reuters reported that the British Secretary of State for Energy and Climate Change strongly advocated for the UK to remain part of the IEM.[1] The same report mentions that in 2016 the UK imported 6% of its electricity from abroad, invested in more interconnectors with Ireland, and expects imports to cover up to 20% of peak-demand by the early 2020s.[2] Given the context of Brexit and the expressed interest of British politicians to continue membership in the IEM, this article investigates the value of the gains from trade that arise under market coupling.[3]

Both the coupling of markets and the idea that trade enhances welfare have received much attention in the energy literature. Neuhoff and Newberry (2005) have examined the welfare consequences of electricity markets coupling and the prospects of market integration in the European context. While arguing for potential welfare gains stemming from market integration, these authors caution that initially there could be price increases and that regulatory cooperation is important to achieve the full potential of market integration. In her study of market integration between the UK and Ireland, Valeri (2009) finds that welfare increases with interconnector capacity and concludes that relying on private incentives alone may lead to underinvestment in interconnector capacity.

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[1] See Chestney (2017).

[2] "Interconnector" is the technical term for an electricity link that connects different countries' national electricity grids.

[3] The interest of the UK in retaining the benefits of the single European electricity market has further been expressed in the letter addressed by the UK Prime Minister to the President of the European Council on August 19, 2019. See https://www.gov.uk/government/publications/pm-letter-to-donald-tusk-19-august-2019.

This article seeks to contribute to the energy literature both in the question analyzed and the methodology used to answer it. Overall, it is somewhat surprising that the study of electricity trade has mainly been considered at a national/firm level rather than at an international/country level. Our article seeks to contribute to filling this void. To the best of our knowledge this article is not only one of the first attempts to analyze gains from electricity trade between neighboring countries, namely, Britain and France, but also to explore the economic consequences on a specific sector of the Brexit political event. Nevertheless, concerning the electricity sector, we should mention a quite recent article by Geske et al. (2019). While this article is close to ours in that it explores the cost of the UK's withdrawal from the IEM, it differs in a few respects.

First, Geske et al. (2019) look at the potential costs of market uncoupling for a 2030-scenario based on data from before market coupling took place. In this article, we use recent (2016) data of the coupled British and French markets to simulate the demand and supply structure of the two markets. Second, the source of inefficiency introduced by these authors is market uncertainty as markets for transmission rights and electricity do not clear simultaneously without market coupling. In fact, even their most extreme scenario, the "Hard Elecxit," assumes some interconnector capacity and trade. In contrast, we use a mechanism that looks directly at the welfare impacts of changes in price that arise from the absence of trade. In this sense, our version of market decoupling is more radical as it compares the *status quo* to the case with no trade.[4] Third, and as is to be expected from the previous remark, our model yields higher potential welfare losses from decoupling.[5]

Adopting a country- rather than a firm-level approach, however, comes at the cost of having to neglect some of the market failures implications of imperfect competition, although our choice of timing in the model somewhat mitigates such a concern.[6] Moreover, we feel that the potential benefits of contributing to understanding the economic consequences on various sectors of such a big political event as the withdrawal of a major country from the EU more than compensate for the costs of making some simplifying modeling assumptions. In fact, some authors have already shown how the economic approach is useful to analyze important political economy issues concerning electricity markets. Among others, Lilliestam and Ellenbeck (2011) have used a bargaining approach to figure out whether the EU would be vulnerable to extortion if it decided to import large quantities of solar energy from North Africa. Our article perhaps shares the theme of this stream of the literature, if not the methodology.

[4] While we don't claim that the existing links will be broken the day Britain leaves the EU, this radical view has the advantage of comprehensively quantifying the benefits that trade generates.

[5] As we will see, our simulations show that these welfare losses surpass 900M€ for the UK alone. This contrasts with the estimate of *circa* 600 M€ for the UK and France, of which more than 50% is born by Great Britain, in the "Hard Elecxit" scenario considered by Gaske et al. (2019). Ambec and Crampes (2019) argue that these authors' estimate might even prove to be too high.

[6] In our model, the level of prices is determined by the cost of the available production technologies. Hence, if a firm with market power increased the price of a technology above cost, it could obtain rents. Although this could have a numerical impact on how consumer surplus and producer surplus are split and allow foreign exporters to increase prices, the resulting flow of electricity would not change as long as the merit order of technologies was not fundamentally changed. This "umbrella effect," of market power, which is more commonly known from the study of cartels, could then even increase the gains from trade in the form of exporters' profit. On umbrella effects, see, e.g., Inderst et al. (2014). Demand, transmission capacity, and capacity would, however, be unchanged by such a price increase.

Turning to methodology, in this article we adopt a computational-analytical approach. More specifically, we formulate a simple theoretical model and illustrate its inner working via a numerical example, before answering the question of interest by a calibration of the model fueled by data on electricity consumption and production in France and the UK. Simulations provide a strong alternative to the traditionally used systems of equations when assumptions that are needed to take into account real-life constraints permit no elegant closed-form solution. Nevertheless, there is a debate on whether economists shun less elegant or less general simulations in favor of models that can be solved analytically.[7] By grounding the calibration of our model with empirical evidence and demonstrating the internal coherence of the model with a large number of simulations, in this article we give the priority to what we see as a more realistic solution over mathematical elegance.

The article is organized as follows. Section 2 describes the legislative and institutional framework surrounding the IEM, which is characterized by national, international, and supranational actors, both private and public, and a set of organizations that coordinate them. This legislative and institutional picture will serve the purpose of helping us in the setting up of the model. Section 3 presents a computational model of two interconnected countries facing stochastic demand and producing with base-load, peak-load, and renewable electricity supply technologies that we use to assess welfare effects of trade. This section also provides, as a check of the coherence of the model, a numerical illustration of the results obtained by simulating it. Section 4 presents a calibration of the model to the case of UK-France electricity trade and discusses the gains from trade for each party. Section 5 concludes. Additional tables and figures used in the discussions are provided in an appendix.

2. The European Internal Energy Market

The institutional framework surrounding the trade of electricity within the EU is quite complex and involves many actors. Both for the better understanding of the underlying economic questions and the justification of our modeling assumptions, this section seeks to give an overview of this framework as far as electricity is concerned. First, we describe the legislation that framed the IEM. Then, we present the current set of actors and their respective roles in the IEM. Finally, we explain the technology and market design that make cross-border electricity trade work between the UK and the rest of Europe.

The legislative framework

The development of the IEM by the EU is defined by the legacy of incumbent electricity generating companies, national regulatory agencies (NRAs), and nationally designed grids. It is also defined by the forward-thrusting initiatives of the EU that have been trying to create the IEM through an expansion of interconnection capacity, harmonized rules for cross-border electricity trade, competition, and greater institutional coherence over the last 20 years. Table 1 below lists the main legislations that shaped the development of the IEM.

[7] Miranda and Fackler (2004) state: "When essential features of an economic system being studied cannot be faithfully captured in an algebraically soluble model, a choice must be made. Either essential features of the system must be ignored in order to obtain an algebraically tractable model, or numerical techniques must be applied. Too often economists chose algebraic tractability over economic realism."

Table 1 - The IEM legislative framework (Electricity)

Year	Legislation	Issue(s)
1990	– Council Directive 90/377/EEC	– Transparency of prices charged to industrial end-users
1990	– Council Directive 90/547/EEC	– Transit of electricity through transmission grids
1996	– Directive 96/92/EC of the European Parliament and of the Council	– Rules for the internal market in electricity – Rules for generation, transmission, and distribution of electricity – Creation of TSOs and interconnectors
2003	– Directive 2003/54/EC of the European Parliament and of the Council	– Rules for the internal market in electricity, repealing Directive 96/92/EC – Production efficiency – Competition in generation, market dominance and predatory behavior – Access to transmission and distribution networks
2009	– Directive 2009/72/EC of the European Parliament and of the Council – Regulation (EC) 713/2009 of the European Parliament and of the Council – Regulation (EC) 714/2009 of the European Parliament and of the Council – Regulation (EU) 2019/942 of the European Parliament and of the Council	– Rules for the internal energy market, repealing Directive 2003/54/EC – Unbundling of energy generation and networks – Creation of the Agency for the Cooperation of Energy Regulator (ACER) – Coordinate the development of network codes within a common organization (European Network of Transmission System Operators for Electricity, ENTSO)

While some of the first EU legislation referencing the IEM was passed in 1990 with Council Directive 90/377/EEC in order "to improve the transparency of gas and electricity prices charged to industrial end-user" (European Commission, 1990a) and Council Directive 90/547/EEC dealing with "the transit of electricity through transmission grids" (European Commission, 1990b), Meeus et al. (2005) date the first real steps towards the IEM to 1996 with the Directive 96/92/EG (European Parliament and Council of the European Union, 1996). This piece of legislation "establishes common rules for the generation, transmission, and distribution of electricity," including the creation of Transmission System Operators (TSOs), in charge of operating and maintaining (national) transmission services, as well as interconnectors with other systems.

This first approach addressed, among other issues, some concerns regarding vertical integration, calling for separate accounts and separate management where TSOs are integrated with the owners of the transmission infrastructure. In 2003, it was succeeded and replaced by Directive 2003/54/EC (European Commission, 2003) acknowledging the "benefits that may result from the internal market in electricity, in terms of efficiency gains, price reductions, higher standards of service, and increased competitiveness", while raising market power concerns. Its main focus at the time was to create "a level playing field in generation and reduce the risks of market dominance and predatory behavior, ensuring non-discriminatory transmission and distribution tariffs through access to the network on the basis of tariffs published prior to their entry into force." The directive established compliance rules for TSOs that were vertically integrated with transmission owners, rules regarding third-party access, and a gradual opening of electricity markets on the demand side, first to industrial customers and then to all customers by 2007.

Finally, the next major step in the development of the IEM was reached in 2009 with the passing of the so-called "Third Energy Package" consisting of two directives, Directive 2009/72/EC for electricity and Directive 2009/73/EC for gas, one authority creation regulation, Regulation (EC) No. 713, and two access regulations, Regulations (EC) No. 714/2009 and 715/2009 for electricity and gas, respectively. The two directives define common rules for the electricity and gas markets while the electricity access regulation defines conditions for access to the network for cross-border exchanges, the gas access regulation defines conditions for access to the natural gas transmission networks, and the authority creation regulation establishes an Agency for Cooperation of Energy Regulators (ACER).

This package sets conditions with regards to the unbundling of transmission capacity and operation and retail competition, as well as provisions concerning natural gas (European Commission, 2009). The ACER replaces the European Regulator Group for Electricity and Gas (ERGEG) since neither ERGEG nor the NRAs were deemed fit to cope with EU-level regulation (European Commission, 2011). In addition, the technical details regarding third-party access, security, and interconnection are dealt with through the so called "Network codes," drafted by the European Network of Transmission System Operators (ENTSO) in accordance with the "Framework guidelines" set by ACER.

Another focus of the 2009 legislation was consumer protection and price transparency. The previous legislation from 2003 was repealed in 2009, namely, Directive 2009/72/EC (European Commission, 2009). This legislation on rules and institutions was accompanied by investment strategies of the European Commission, such as the "Energy 2020" and "Energy 2030" strategies. The current state of the IEM is regularly reported in progress reports from the European Commission to the other bodies of the EU.[8] The EU seeks to reconcile both economic and political goals with its policies. Apart from cost savings, economic growth, and jobs, the EU Commission's sets goals to the development of the IEM that include stability and security of energy supply and the reduction of greenhouse gas emissions, most importantly, carbon dioxide.

Key aspects of the EU electricity market structure

The market structure of the European electricity sector has become increasingly complex over time due to a flurry of EU regulation that has created an unwieldy amount of institutions, each playing a role in the creation of the IEM. Table 2 summarizes some

[8] See European Commission (2012 and 2014).

important aspects of EU electricity market structure, from both the value chain and property rights and physical side, which we discuss next.

Table 2 - EU electricity industry's main actors and their role: Value chain and property rights and physical side

Value chain		Property rights and physical side	
Actor(s)	Role	Option 1	Option 2
Producers	Generate electricity		
Energy exchange	– Aggregation of bids to supply and demand curves – Matching of bids according to a merit order	Producers dispatch energy	Producers dispatch energy
Wholesalers	– Submission of bids – Electricity trade	Producers own the grid	TSOs own the grid
Retailers	– Selling electricity to final consumers	ISOs manage the grid	TSOs manage the grid
Consumers	– Electricity consumption	Consumers receive electricity	Consumers receive electricity

On the local level there are electricity generators and consumers. The demand from consumers and the supply from electricity producers are matched at electricity exchanges where wholesale agents or retailers bid for electricity offered by the producers.[9] The matching process typically happens in the form of forward auctions, e.g., day-ahead markets for short-term contracts and is usually accompanied by financial contracts that allocate the risk of price fluctuations between the parties.

The transmission of electricity happens through high-, medium-, and low-voltage links that have been historically owned by large electricity-producing companies, but which in some cases have been transferred to independent companies. In any case, with respect to EU law, the management and maintenance of these transmission links has to be separated from the generation of electricity. The reason for this is that transmission capacity serves as part of the value chain from electricity generation to retail and that vertical integration of these activities is therefore deemed undesirable from a competition standpoint as it raises concerns of market power and foreclosure.

Directive 2009/72/EC leaves EU member states with different options to implement this separation. The management and maintenance of the transmission links may be allocated to TSOs, which can be natural or legal persons separate from electricity producers and are subject to strict compliance rules to ensure their independence. The goal here is to allow

[9] Two examples of such exchanges are *Nord Pool,* covering the Nordic and Baltic countries, Germany, and the UK and *EPEX Spot*, operating mainly in Germany, France, the UK, and the Benelux countries. Several exchanges can be competing in the same country.

access to the transmission network to all producers under equal conditions, thus creating a level playing field and preventing large electricity producers owning transmission links from foreclosing rivals.

Alternatively, where ownership of transmission links remains with producers, the creation of ISOs is an option. ISOs are entities owned by the electricity producing companies but are under strict rules to exclude conflicts of interest with the transmission owners, mainly to ensure third-party access without interference of the transmission owner. This form of independent management can be organized in the form of a fully owned subsidiary with a separate branding.[10]

In any case, each TSO is represented at the European level through the European Network of Transmission System Operators (ENTSO) the main responsibility of which is to design the network code and set the technical specifications that allow the flow of electricity between different markets. However, even though TSOs appear to be the more divested option, there are some political concerns, especially in the UK, about the possibility of conflicts of interest with TSOs being "system operators and for-profit owners of energy infrastructure" (a point raised in a report by the law firm Pinsent Masons LLP, 2016).

Table 3 below lists the main actors of the energy sector, namely, NGOs, private operators, and regulators at the European, international, and national level. NRAs are in charge of enforcing the rules and laws that govern the European electricity markets. They also act to protect consumers. Recognized by EU directives, they are mandated to be independent of the national executive branch of governments and other actors in the electricity market. At the European level, they form two bodies, namely, the Agency for the Cooperation of Energy Regulators (ACER) and the Council of European Energy Regulators (CEER). With the phasing out of the European Regulators Group for Electricity and Gas (ERGEG) in 2011, some of its tasks have been taken over by ACER, which is an independent body of the EU and mainly charged with legislation, while CEER focuses on cooperation in other complementary fields of pan-European interest, such as smart grids, sustainability, and customer issues. Even though both work towards the realization of the IEM, their tasks are complementary and not overlapping.

Table 3 - Energy NGOs, private operators, and regulators at the European, international, and national level

Level	Actor(s)				
European	EURELECTRIC	EFET	ACER	CEER	ENTSO
International	(Most) energy companies	Energy exchanges			
National	National trade associations		NRAs		

On the business side, the European Federation of Energy Traders (EFET) is the trade association of electricity exchanges in Europe that represents the common interest of

[10] Note that ISOs are more common in the United States.

electricity exchanges at the European level. The electricity generating companies have a similar body named EURELECTRIC, the union of national trade associations in the electricity-generating sector.

Electricity trade between the UK and the rest of Europe

How is the UK electricity network connected to the rest of Europe? Currently, *National Grid*, the UK's TSO, is involved in several business ventures. First, there is the High Voltage Direct (HVDC) Cross-Channel interconnector that is a bi-directional link with a capacity of 2,000 megawatt hours (MWh) operational since 1986 between the British and French electricity grids.[11] It is jointly owned and managed by a subsidiary of *National Grid*, namely, *National Grid Interconnectors Limited*, and the French TSO *Réseau de Transport d'Électricité* (RTE). Another interconnector with capacity of 500 MWh links the UK and Ireland and further interconnectors between the UK and France, Belgium, Denmark, and Iceland are being planned.

In addition to these interconnectors, the 260-km interconnector *BritNed* links the UK and the Netherlands since 2011. This interconnector with a capacity of 1000 MWh is bi-directional and is operated by *BritNed Development Ltd*, a joint-venture of *National Grid* and *NLink*, a subsidiary of the Dutch-German TSO *TenneT*. The trade of electricity passing through this interconnector is organized in both explicit auctions, run on a proprietary platform of *BritNed Development Ltd*, and implicit auctions, run on *EPEX Spot*, an electricity exchange.[12]

These interconnectors facilitate international trade of electricity through a mechanism called "Market Coupling." Following information provided directly by *EPEX Spot*, this mechanism works as an addition to the regular auctions that are organized at each electricity exchange (EPEX Spot, 2017). Each bidder provides a series of bids, where each bid specifies a quantity that the participant wants to buy or sell at a specific price. Auctions are blind, i.e., the participants do not see other bids. The set of bids allows the exchange to specify individual supply and demand curves that are aggregated and used to return an auction outcome. All of this happens nationally. However, when two markets are coupled and connected through an interconnector, the exchange changes the allocation so that the price difference between the two markets is as small as possible, subject to the capacity constraint of the interconnector. As a result of efficient market coupling, greater price convergence is thus expected to happen.[13]

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[11] This HVDC interconnector, or *Interconnexion France-Angleterre* in French, is operated under the English Channel to import or export electricity between France and Britain depending upon market demand conditions. This link will be at the center of the calibration exercise of the two-country model that we perform in this article.

[12] In explicit auctions transmission capacity on an interconnector is auctioned off separately from the electricity itself. In contrast, implicit auctions integrate the trade of electricity and the respective transmission rights. According to industry members (See, e.g., EPEX Spot, 2017 and Nord Pool, 2017), implicit auctions are more efficient as they aggregate more information and prevent inefficient underutilization or adverse flows of electricity resulting in welfare losses.

[13] In our model, we assume that first the market clears nationally and then opportunities for trade are realized. In the literature, spot prices correlation and price convergence have been widely used as an indication of the degree of integration of electricity markets. See, among others, Brunekreeft et al. (2005) and Zachmann (2008). Our goal in this article, however, is to study the economic impact of market coupling, particularly on the trading countries producers' and consumers' welfare.

3. The Model

Our modeling approach draws on work that goes back to the seminal contributions of Marcel Boiteux on peak-load pricing (Boiteux, 1949, 1951). In an efficient market, at equilibrium, electricity is priced at the marginal cost of the technology with the highest marginal cost that is used to satisfy demand. The available generation technologies are ordered according to their marginal cost and supply obeys the so-called "merit order" according to which the technologies with lower marginal cost are dispatched first and more expensive generation units are successively brought online as demand increases. When future demand is unknown though, a market needs more capacity than the expected level of demand in order to minimize the possibility of excess demand.[14] As future demand is unknown, it is not possible, let alone economically feasible, to guarantee that demand is satisfied at all times.

To find the appropriate price when demand cannot be satisfied, different approaches have been proposed. Bental and Ravid (1982) develop a pricing mechanism based on firms' revealed preferences while Anderson and Taylor (1986) provide an overview of different other methods resting on the determination of the "social cost of unsupplied electricity," including some based on willingness-to-pay. The issue of pricing the value of electricity that cannot be supplied is also central to the literature on reserve capacity.[15] It is closely related to the concept of the average marginal willingness to pay of all consumers that cannot be served, the so-called "Value of Lost Load" (VoLL).

According to the principles of peak-load pricing, the VoLL would be the efficient peak price. From a dynamic perspective, Joskow and Tirole (2007) consider the VoLL as the cap to which prices should spike at times of excess demand to ensure correct capacity investment incentives. In our model, we will introduce the notion of VoLL, but we will assume a fixed amount of installed capacity, treating investment as sunk and exogenous, hence abstracting away from investment incentives issues. Moreover, VoLL is introduced as an exogenous parameter used to determine market price when capacity is insufficient.[16] Laffont and Tirole (1993) emphasize that peak prices must be high enough to cover long-run marginal cost including the cost of capital. Stoft (2002) argue that these "scarcity rents" are needed to cover the fixed cost of capital of the plant with the highest variable costs.

This section introduces our model of two countries that cover their electricity demand with supply coming from three different technologies, namely, renewable, base-load, and peak-load. We first describe the key defining variables and parameters of the model (Section 3.1). Then, we discuss how exactly we simulate the model in what we consider in this article as the "benchmark" scenario, namely, the case without trade (Section 3.2). Next, we

[14] Network capacity planning is an important aspect of security of electricity supply. See, e.g., Finon and Pignon (2008) for an introduction to capacity planning.

[15] Reserve capacity generally refers to installed equipment that is in excess of that required to carry peak load and hence, as such, it concerns a broad range of economic activities.

[16] Léautier (2016) argues that while precise estimation of VoLL is impossible, commonly accepted values are in the 10,000-20,000 $/MWh range. In a 2013 report prepared for the UK regulator, OFGEM, and the former British government department, DECC, the London Economics consultancy company estimated the VoLL for the UK to around 19,700 €/MWh (London Economics, 2013).

introduce trade (Section 3.3). Finally, we illustrate the working of the model using a numerical example (Section 3.4).[17]

3.1 Notation

An iteration, denoted by the period index t in the model, corresponds to the electricity market with two countries producing, consuming, and trading electricity at a certain hour on a certain day. Each country $i\epsilon\{A, B\}$ faces stochastic demand for electricity, measured in MWh, and produces electricity using three technologies:

- Renewable (rw) energy sources that produce a varying, but fixed amount of electricity $Q^i_{rw,t}$. The amount that is produced is stochastic, according to some known cumulative distribution function (cdf) F with a probability density function (pdf) f, at a constant per-unit cost c^i_{rw}.
- Base-load (bl) generating plants in total number N^i, e.g., nuclear reactors, each with a fixed and lumpy electricity output of α^i, so that each country can generate output from this technology, $Q^i_{bl,t}$, up to $\bar{Q}^i_{bl} \equiv \alpha^i N^i$ at a constant "virtual" marginal cost c^i_{bl}.[18]
- Peak-load (pl) generating plants that can generate an amount of electricity $Q^i_{pl,t}$ up to $\bar{Q}^i_{pl}$ at a constant per-unit marginal cost of c^i_{pl}.

We assume that the marginal costs satisfy $c^i_{rw} \leq c^i_{bl} \leq c^i_{pl}$, an inequality that is in line with the basic properties of most electricity generating technologies. Indeed, sun and wind are free (although biomass, also a form of renewable energy, is not), the fuel costs of big base-load nuclear power plants are low relative to their output, while more flexible fossil fuel plants like coal and particularly gas have higher fuel costs.[19] Installation costs are all sunk so that we consider short-term equilibria where production and dispatch decisions are driven by marginal costs.

Electricity is dispatched according to the merit order. Hence, to cover demand, first all renewable energy enters the grid, then the optimal number of base-load plants to dispatch electricity is determined. Peak-load electricity is generated if either demand exceeds renewable energy generation plus base-load capacity or it is more efficient to dispatch peak-load electricity than dispatching an additional base-load plant.[20] Following the peak-load

[17] In Section 4, we run the model by first calibrating it to British and French 2016 data on consumption and production.

[18] The term "virtual" here reflects the fact that base-load plants supplies of electricity, $Q^i_{bl,t}$, are only available in chunks of α^i, so that bringing in one more generator online always costs $\alpha^i c^i_{bl}$ regardless of the proportion of electricity that is effectively used. Essentially, this could also be considered an average production cost per reactor. Surplus electricity that is not exported is thus wasted.

[19] Note that only c^i_{pl} is a marginal cost in the classical sense, i.e., it is the effective cost of one more unit of electricity produced with peak-load technology. As already indicated, base-load production is not incremental in the model. Renewable energy production is random and always fully dispatched so that no incremental production decision can be made.

[20] This will be the case if the remaining demand, net of renewable electricity and all fully utilized base-load reactors, is small relative to the capacity of one base-load plant. This is described further below in section 3.2 under the "in-between case."

principle, the wholesale price is assumed to be equal to the marginal cost associated with the technology with the highest variable cost. As mentioned above, base-load plants are assumed to be lumpy. Hence, base-load generation output only takes values

$$Q_{bl,t}^{i} = \left(\frac{n_t^i}{N^i}\right) \bar{Q}_{bl}^{i} = \alpha^i n_t^i \quad (1)$$

where $n_t^i \in \left[0, N^i\right]$ is the number of base-load generation units put online in period t.

The hourly demand for electricity D_t^i is inelastic in each period, but varies stochastically between periods according to a known cumulative distribution function (cdf) G with a probability density function (pdf) g. The realization of demand is observed at the beginning of the period. In the numeral example that we have produced and later discuss, we confine ourselves to independent and identically distributed (i.i.d.) random variables representing demand while in section 5 we synthesize actual demand data in a linear functional form to capture real-life fluctuations.

Electricity generators behave competitively, resulting in marginal cost pricing with the qualifications given above. Although this may admittedly appear as a strong assumption given the oligopolistic market structure in many electricity markets, efficient auctions design at electricity exchanges should induce competitors to truthfully reveal their costs, hence resulting in an efficient allocation.[21] The VoLL of country i is denoted by $VoLL^i$. As indicated above, for an iteration t, this parameter represents both consumers' willingness-to-pay and the price to which electricity will spike when demand exceeds the maximum production capacity, which is given for any period by

$$\bar{Q}_t^i = Q_{rw,t}^i + \bar{Q}_{bl}^i + \bar{Q}_{pl}^i \quad (2)$$

For completeness, we denote total electricity production by

$$Q_t^i = Q_{rw,t}^i + Q_{bl}^i + Q_{pl}^i \quad (3)$$

3.2 The no-trade case

We describe the model first in the simple case without trade, i.e., under autarky. At the beginning of any iteration the realizations of demand and renewable energy production become known. The program then proceeds as follows.

Partial blackout

The program first checks whether or not the total capacity suffices to cover demand. Should demand exceed the production capacity in the country, we are in a situation of (partial) blackout. In terms of production and prices this means that all electricity resources are utilized, i.e., all base-load plants are online and peak-load generation is at its maximum

[21] For the case of the US, Salant (2004) provides an overview of different types of auctions. Joskow and Tirole (2000) analyze market power in electricity transmission.

capacity, and the wholesale price of electricity, denoted by P_t^i, spikes to $VoLL^i$. Hence, consumer surplus, producer surplus, and total surplus are respectively given by

$$CS_t^i = \left(VoLL^i - P_t^i\right)\left(Q_{rw,t}^i + \bar{Q}_{bl}^i + \bar{Q}_{pl}^i\right) \quad (4)$$

which is equal to 0 in the case of partial blackout ($P_t^i = VoLL^i$)

$$PS_t^i = \left(VoLL^i - c_{rw}^i\right)Q_{rw,t}^i + \left(VoLL^i - c_{bl}^i\right)\bar{Q}_{bl}^i + \left(VoLL^i - c_{pl}^i\right)\bar{Q}_{pl}^i \quad (5)$$

$$TS_t^i \equiv CS_t^i + PS_t^i = \left(VoLL^i - c_{rw}^i\right)Q_{rw,t}^i + \left(VoLL^i - c_{bl}^i\right)\bar{Q}_{bl}^i + \left(VoLL^i - c_{pl}^i\right)\bar{Q}_{pl}^i \quad (6)$$

Abundant renewables

If there is no blackout, the program then checks whether or not the renewable energy production alone suffices to cover demand. If it does, then the total electricity production is equal to renewable production. No electricity from base- or peak-load sources is dispatched and $P_t^i = c_{rw}^i$. We thus have in this case

$$CS_t^i = \left(VoLL^i - c_{rw}^i\right)D_t^i \quad (7)$$

$$PS_t^i = c_{rw}^i\left(D_t^i - Q_{rw,t}^i\right) \quad (8)$$

$$TS_t^i = VoLL^i \cdot D_t^i - c_{rw}^i \cdot Q_{rw,t}^i \quad (9)$$

Excess electricity in this case is merely lost. The producers have no way of reducing renewable energy production below the stochastic realization and therefore cannot recover their costs in that period. While these costs will be the determinants of prices at the margin, we must say that neither in the calibration exercise nor under any plausible values of simulation parameters will we observe renewables as playing a pivotal role in price setting. Still, the value of c_{rw}^i impacts the results of the model through the channel of welfare, which is determined by the consumers' willingness-to-pay net of production costs.[22]

In-between case

In the "in-between case," some combination of base-load and peak-load generation units are used to cover demand. First, given the residual demand after dispatching renewable energy, the program computes the number of base-load plants that can operate at full-capacity among the available base-load plants. Then, it computes the cost of covering the residual volume, after dispatching renewable and these full capacity base-load plants, either with one additional base-load plant (subject to availability) or with peak-load electricity. This residual volume, denoted by Δ_t^i, is given by

[22] Excitement about a peak in German renewable generation representing a high percentage of demand that even reached the business press is a good illustration of how much of a fringe case high renewable generation is (Shankleman, 2016).

$$\Delta_t^i = D_t^i - Q_{rw,t}^i - \alpha^i \underline{n}_t^i \quad (10)$$

where $\underline{n}_t^i$ is the minimum of the number of base-load power plants that can be operated at full capacity and the number of available base-load plants.

Note that by having checked for a partial blackout earlier, at this stage it is always possible to cover demand by dispatching all base-load and peak-load units. Since peak-load electricity has a higher marginal cost but base-load electricity only comes in lumps of α^i, it is "more likely" that peak-load electricity is used to cover the residual if it is small relative to the production of one additional plant. But, it is "more likely" to bring online one additional base-load plant if it can operate at high capacity, i.e., if Δ_t^i/α^i is close to 1. Indeed, an additional available base-load plant will be dispatched if

$$\alpha^i c_{bl}^i < \Delta_t^i c_{pl}^i \quad (11)$$

In both cases, the market price for electricity is equal to the generation marginal cost, i.e., c_{pl}^i in the former case and c_{bl}^i in the latter. Consumer surplus, producer surplus, and total surplus are computed as in the partial blackout case of the no-trade situation described above and the results of this simple setup will serve as the benchmark against which we compare the outcome of the two-country trade we introduce next.

3.3 The two-country trade case

We now consider the setup where the first stage of national market clearing is followed by a second stage in which trade occurs. We assume that the electricity markets of Countries A and B are linked through an interconnector with a maximum transmission capacity of Q_K. In each of the three cases of the first stage, two additional variables are introduced, namely, the amount of electricity that a country can offer for trade, V_t^i, and the price at which this electricity is offered, pv_t^i. The values of these two variables depend on the first-stage result.

In the case of partial blackout in Country i, it offers no electricity to sell. Hence, no export occurs from this capacity-constrained country so that $V_t^i = 0$ and $pv_t^i > \max\{VoLL^A, VoLL^B\}$.[23] In the case of abundant renewable production, the difference between demand and production, i.e., the excess renewable energy that went to waste under autarky is now offered for export at a price equal to marginal cost. Hence, $V_t^i = D_t^i - Q_{rw,t}^i$ and $pv_t^i = c_{rw}^i$. In the in-between case and when Country i decides to dispatch one additional base-load power plant to operate at less than full capacity to cover residual demand, the excess electricity from this plant is offered at a price equal to its virtual marginal cost. Thus, $V_t^i = (\alpha^i - \Delta_t^i)$ and $pv_t^i = c_{bl}^i$. If instead there is positive production of peak-load electricity, the difference between the maximum peak-load capacity and the peak-load capacity used is offered in the market at a price equal to marginal cost. Formally, $V_t^i =$

[23] In the simulation presented in section 4, we set pv_t^i to an arbitrarily chosen high value.

$\left(\bar{Q}_{pl}^{i}-\Delta_{t}^{i}\right)$ and $pv_{t}^{i}=c_{pl}^{i}$. In the empirical analysis, the countries' imports are denoted by $Import^{i}$, $i\epsilon\{A,B\}$.

There is a consequence of this program that is worthwhile pointing out here. Observe that in no case is a power plant ever turned online solely for the purpose of exporting electricity. Only residuals are exported. In practice, this could lead to an inefficiently low amount of trade, for example when one country only offers unused electricity from a base-load plant but could in theory profitably dispatch peak-load electricity in addition. This constraint of the model does, however, mirror the market-coupling program described in section 2.

After this first stage of production decision with simultaneous definition of export quantities and prices, each country checks its demand for electricity. If Country A's market price is above the price at which Country B offers to export, Country A imports as much electricity as it can, constrained either by the interconnector capacity or the exporting country's supply. Then, if imported electricity becomes "pivotal," the resulting price changes in the importing country are computed as well as the consumer, producer, and total surpluses as above.[24]

For the very purpose of this article, we resort to a numerical approach to solve the model. Let us note that the model admits multiple solutions. Denote by (P^{A},P^{B}) the pair of prices that prevail in Countries A and B. Then, the total number of possible such pairs of prices, $\{\#(P^{A},P^{B})\}$, is given by

$$\begin{aligned}\{\#(P^{A},P^{B})\} &= \left|\left\{\left\{c_{rw}^{A},c_{bl}^{A},c_{pl}^{A},VoLL^{A}\right\}\times\left\{c_{rw}^{B},c_{bl}^{B},c_{pl}^{B},VoLL^{B}\right\}\right\}\right| \\ &\quad + \left|\left\{(c_{rw}^{A},c_{rw}^{A});(c_{rw}^{B},c_{rw}^{B});(c_{bl}^{A},c_{bl}^{A});(c_{bl}^{B},c_{bl}^{B});\left(c_{pl}^{A},c_{pl}^{A}\right);\left(c_{pl}^{B},c_{pl}^{B}\right)\right\}\right| \\ &= 22 \end{aligned} \quad (12)$$

More explicitly, it is equal to 16 (4×4), the number of possible price pairs obtained by crossing the two sets $\left\{c_{rw}^{A},c_{bl}^{A},c_{pl}^{A},VoLL^{A}\right\}$ and $\left\{c_{rw}^{B},c_{bl}^{B},c_{pl}^{B},VoLL^{B}\right\}$, i.e.,

$$\left\{\begin{aligned}&(c_{rw}^{A},c_{rw}^{B});(c_{rw}^{A},c_{bl}^{B});\left(c_{rw}^{A},c_{pl}^{B}\right);(c_{rw}^{A},VoLL^{B});(c_{bl}^{A},c_{rw}^{B});(c_{bl}^{A},c_{bl}^{B});\\ &\left(c_{bl}^{A},c_{pl}^{B}\right);(c_{bl}^{A},VoLL^{B});\\ &\left(c_{pl}^{A},c_{rw}^{B}\right);\left(c_{pl}^{A},c_{bl}^{B}\right);\left(c_{pl}^{A},c_{pl}^{B}\right);\left(c_{pl}^{A},VoLL^{B}\right);(VoLL^{A},c_{rw}^{A});(VoLL^{A},c_{bl}^{B});\\ &\left(VoLL^{A},c_{pl}^{B}\right);(VoLL^{A},VoLL^{B})\end{aligned}\right\} \quad (13)$$

[24] The term "pivotal" is used here to indicate that it is the price of the imported electricity that effectively determines the price. Imports become pivotal if they allow to cover demand when there is a partial black-out or if they crowd-out a costlier technology from the energy mix in a given period.

to which the 6 pairs of prices corresponding to the cases where a price determined by one of the three technologies' cost carries over from one country to the another through trade, i.e.,

$$\{(c_{rw}^A, c_{rw}^A); (c_{rw}^B, c_{rw}^B); (c_{bl}^A, c_{bl}^A); (c_{bl}^B, c_{bl}^B); (c_{pl}^A, c_{pl}^A); (c_{pl}^B, c_{pl}^B)\} \quad (14)$$

are added. In practice, depending on the cost parameters and the capacity of different technologies relative to demand, fewer combinations of prices will eventually emerge.[25] However, the outcome can be affected by the quantities traded in each iteration and depends on demand and production of electricity from renewable sources, both of which are assumed to be stochastic in the model.

Further complexities militate for a numerical solution option. Indeed, the realization of the random variables in the first stage in which national market clearing occurs can lead to up to 16 different cases, each leading in the second stage either to no trade or trade in one or the other direction, subject to several constraints. The trade algorithm allows for possible "feedback effects" from the second stage to the first stage, e.g., when Country A imports from Country B so that the market price in Country A decreases after accounting for trade and producer surplus in Country A has to be adjusted downwards.

3.4. A numerical example

To further discuss the implications of the different cases presented above, we now consider a numerical example. Table 4 below lists the model's variables that are country- and period-specific, the model's parameters that are either only country-specific or common to the two countries, and their designations. Let us assume the following values for the parameters of the model:

$$c_{rw}^A = c_{rw}^B = 0.1;\ c_{bl}^A = 1.1, c_{bl}^B = 1.0;\ c_{pl}^A = 2.2, c_{pl}^B = 2.0;\ VoLL^A = VoLL^B = 10 \quad (15)$$

$$N^A = N^B = 10;\ \alpha^A = \alpha^B = 250;\ \bar{Q}_{pl}^A = \bar{Q}_{pl}^B = 500 \quad (16)$$

$$Q_{rw}^i \sim F(0{,}400), D^i \sim G(2700, 300), i \epsilon \{A, B\} \quad (17)$$

where F and G are the cumulative functions of the uniform and normal distributions respectively. While in this example we model the production of electricity from renewable technology and demand as random variables following the uniform and normal distributions respectively, in the next section we fit actual data on these variables to linear functions. We further assume that the maximum transmission capacity on the interconnector that links the electricity markets of Countries A and B is equal to 100 MWh, i.e., $Q_K = 100$. To simulate the solution and approximate the welfare levels associated with these parameter values, we run 1,000,000 iterations of the model.[26] Table A.1, given in the appendix, reports the

[25] The numerical example provided in the next section will produce only 12 different price pairs.

[26] These simulation results have been obtained with a seed of a random number generator that allows for replication. The program used is available from the authors upon request.

minimum, the first quartile, the median, the mean, the third quartile, and the maximum values of variables of the model the designations of which are given in Table 4.

Table 4 - Variables and parameters of the model+

Variable/Parameter	Designation
Q_{rw}^{i}	Electricity production with renewable technology in country *i* (MWh)
(F, f)	Cumulative distribution and density of the renewable technology
c_{rw}^{i}	Per-unit cost of the renewable technology (€/MWh)
Q_{bl}^{i}	Electricity production with base-load technology in country *i* (MWh)
N^{i}	Total number of base-load plants in country *i*
α^{i}	Electricity generation per base-load plant in country *i* (MWh)
n_{bl}^{i}	Number of active base-load plants in country *i*
$\bar{Q}_{bl}^{i}$	Max. electricity production with base-load technology in country *i* (MWh)
c_{bl}^{i}	Per-unit cost of the base-load technology (€/MWh)
Q_{pl}^{i}	Electricity production with peak-load technology in country *i* (MWh)
c_{pl}^{i}	Per-unit cost of the peak-load technology (€/MWh)
$\bar{Q}_{pl}^{i}$	Max. electricity production with peak-load technology in country *i* (MWh)
D^{i}	Demand for electricity in country *i* (MWh).
(G, g)	Cumulative distribution and density of demand for electricity
$\bar{Q}^{i}$	Max. production capacity in country *i* (MWh)
Q^{i}	Total electricity production in country *i* (MWh)
P^{i}	Price of electricity in country *i* (€/MWh)
CS^{i}	Consumer surplus in country *i* (€ equivalent)
PS^{i}	Producer surplus in country *i* (€ equivalent)
TS^{i}	Total surplus in country *i* (€ equivalent)
Δ^{i}	Residual volume not covered by *rw* and full capacity *bl* in country *i* (MWh)
$\underline{n}^{i}$	Min. {# full-capacity base-load plants, # available base-load plants}
$bmCS^{i}$	Consumer surplus before trade (benchmark) in country *i* (€ equivalent)
$bmPS^{i}$	Producer surplus before trade (benchmark) in country *i* (€ equivalent)
$bmTS^{i}$	Total surplus before trade (benchmark) in country *i* (€ equivalent)
bmP^{i}	Price of electricity before trade (benchmark) in country *i* (€/MWh)
Q_{K}	Interconnector capacity (MWh)
V^{i}	Surplus electricity available for trade in country *i* (MWh)
pv^{i}	Price at which electricity is offered by country *i* for trade (€/MWh)
$Import^{i}$	Imports of country *i* (MWh)
$Shortfall^{i}$	Difference between domestic electricity demand and capacity when domestic demand exceeds capacity (before trade) in country *i*
$IndBlackout_{t}^{i}$	Dichotomous indicator of a peak at period t in country *i*
$bmIndBlackout_{t}^{i}$	Dichotomous indicator of a peak at period t before trade (benchmark) in country *i*
$Blackout^{i}$	Total number of peak periods in country *i* (sum over t of $IndBlackout_{t}^{i}$)
$bmBlackout^{i}$	Total number of peak periods before trade (benchmark) in country *i* (sum over t of $bmIndBlackout_{t}^{i}$)

+ For simplicity of presentation, for each of the variables of the model the superscript *i* indicating the country is kept, but the subscript *t* indicating the period is dropped, except for period indicators for blackout.

It is worthwhile noting that most entries in Table A.1 are of a descriptive nature, reporting some statistics of the variables and parameters listed in Table 4. Some of these variables are more important for the computations within the model, but not for the interpretation of the outcome, for example $Shortfall^i$, which describes the difference between domestic production and domestic demand before trade whenever the latter exceeds the former. The prefix "bm", used as an abbreviation for "benchmark", designates values of a variable measured before trade to allow comparison of the values of this variable before and after trade. This is particularly the case of the couples of variables $\left(Blackout^i, bmBlackout^i\right)$, $i\epsilon\{A, B\}$, given in Table A.2, that inform us about the number of on-peak periods before trade and after the model has been computed with trade and hence allow us to compare them. However, for the purpose of this article, the most relevant values to compare are the couples of variables corresponding to consumer surplus, producer surplus, and total surplus.

As can be seen from Table A.1, the stochastic variables Q^i_{rw} and D^i, $i\epsilon\{A, B\}$ behave as expected given the values assumed for the first and second moments of their distributions. The base-load plants run almost always at full capacity of 2,500 MWh in both countries with mean volume of 2,375 MWh (See the columns of Q^i_{bl}, $i\epsilon\{A, B\}$). Prices P^i, $i\epsilon\{A, B\}$ vary between 1, the unit-price of base-load electricity in Country B, and 10, the value of $VoLL$, which has been fixed at the same value for both countries in this example. To get a further idea of the accuracy of the simulations, one can compare the relative occurrence of each case to the probability determined by the distributions and the program. Table A.3 shows the frequency of the pairs of observed prices, (P^A, P^B), after trade occurs. Each cell reports the number of times the corresponding pair of prices occurred in the 1,000,000 iterations. This table shows, e.g., that in 3,590 of the 1,000,000 cases we obtain (10,10), i.e., a simultaneous partial blackout.[27]

Indeed, comparing the levels of consumer surplus, producer surplus, and total surplus under the benchmark situation without trade with the levels attained under trade, i.e., $bmCS$, $bmPS$, and $bmTS$ versus CS, PS, and TS allows us to assess the welfare effects of trade in each country. As shown in the corresponding columns of Table A.1, in the simulation of the model, trade increased the average level of consumer surplus in both countries. It appears then that, overall, trade has unambiguously, though not surprisingly, benefited consumers in both countries.

The situation is however not that unambiguous when it comes to producer surplus. We found that in Country A the introduction of trade decreased average producer surplus. In Country B, the introduction of trade also decreased average producer surplus. When we examine the aggregate effect of trade, we see that all the statistics of total surplus increase consecutive to trade as can be seen from Table A.1. Based on these results, it seems reasonable to say that, globally, while trade has increased the sum of consumers' and producers' surpluses in both countries, it did not result in a Pareto welfare improvement for consumers and producers.

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[27] The interested reader might want to compute the probabilities of ending up in each of the twelve cases shown in Table A.4.

What seems to be happening is the following. Country A tends to import more electricity than Country B, which is to be expected given its higher cost for all technologies. From Table A.1, we see that in each period, Country A imports on average 45.03 MWh and uses the full 100 MWh capacity of the interconnector in more than three-quarters of all periods as can be seen from the 3rd quartile of the distribution. Country B imports only 12.6 MWh on average and nothing at all in most periods, although in some periods Country B also makes use of the full capacity of the interconnector by importing 100 MWh. In Country A, the imports will only benefit consumers when cheaper foreign electricity is pivotal or alleviates a blackout. If, however, transmission capacity is small, this will rarely be the case.[28] In these cases, it follows from the description of the model that producer surplus in Country A may fall if the producers now sell less electricity from a base-load plant without being able to shut it off and decrease their costs, wasting electricity. Aggregate welfare in Country A might then be lower because producers have the same costs, less revenue, and no domestic party can appropriate any of the gains from trade. Only the exporting industry of Country B will enjoy a benefit, limited as it is by transmission capacity. Overall, Country B's producers can lose too, because whenever trade can prevent a partial blackout in this country, its producers lose some of their most profitable periods.

The overall effect is a shift in welfare from producers to consumers. For example, average consumer surplus per period in Country A rises from 20,318 € to 20,909 € and in Country B from 20,767 € to 21,349 €, which represent an increase of 2.8 and 2.9%, respectively. Meanwhile, average producer surplus per period decreases from 3,671.9 € to 3,123.9 € in Country A and from 3,484.6 € to 2,983.2 € in Country B, i.e., by 14% and 15%, respectively. The overall change in total surplus is positive in both countries, although small. As can be seen from Table A.1, average total surplus per period increases from 23,990 € to 24,033 € in Country A and from 24,251 € to 24,332 € in Country B, i.e., by 0.18% and 0.33%, respectively. The change on a period-by-period basis can be relatively large for producers but tends to be relatively small for consumers. This is so because in most periods producers make only small inframarginal rents so that the partial blackouts are relatively "valuable" while consumer surplus does not vary as much across off-peak periods for the chosen values of the parameters, in particular, a willingness-to-pay, expressed through $VoLL^i$, which is much higher than the production cost.[29]

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[28] The meaning of the term "small" in this context depends on the size and variability of demand and production. In the periods with the greatest discrepancy between domestic demand and domestic production, reported as the maximum of the variable $Shortfall^i$, this discrepancy approximately represents a volume of 1,000 MWh, which is ten times as high as the capacity of the interconnector.

[29] In some cases, trade increases total surplus for both countries individually and collectively. Take the case when one country produces more base-load electricity than it uses. This electricity would be wasted under autarky. When it is sold, producers in this country gain additional revenue at no additional cost. The importing country might use this electricity to overcome a shortfall in electricity and move from being "on-peak", to prices equal to the cost of peak-load electricity generation. Producers in the importing country lose revenue, first, because prices fall from the willingness-to-pay to the price of producing peak-load electricity and second, as they reduce peak-load electricity generation. Consumers in the importing country fully appropriate the welfare loss of producers in the importing country from falling prices as their own surplus. Additionally, they gain surplus from all the additional electricity that is now consumed but would not have been consumed under autarky. This quantity can be larger than the quantity by which producers in the importing country reduce their production.

The model is generally well-behaved and changes in key parameters have a predictable impact on final outcomes. Notably, changes to $VoLL^i$ result in changes to consumer welfare that are linear in the quantity consumed in off-peak periods and changes to producer welfare that are linear in the quantity produced in on-peak periods. Variations in the cost spread between base-load and peak-load electricity have a smaller impact, which is directly related to the proportion of base-load electricity sold in a country in periods when prices are above the cost of producing base-load electricity in that country. The proportion of such periods depends in turn on the realizations of demand and renewable energy, as well as the parameters that govern the “lumpiness” of base-load electricity (number of plant and production per plant).

4. Application to UK-France trade

In the introduction of this article we have directed attention to the fact that British officials have publicly claimed that the UK values access to the IEM. Can we quantify the worth of access to the IEM to the UK? This is the question we seek to explore next by calibrating the model developed in the previous section using data on the UK and France.

Let us assume that the trading countries in the model developed in Section 3, Countries A and B, are the UK and France respectively. Now, the resolution algorithm works exactly as already described but, to better reflect the case of the UK-France trade, instead of inputting random realizations of renewable source electricity generation and total electricity demand as drawn from the distributions F and G, we use the fitted values of dependent variables obtained from regressions of observed renewable source electricity generation and total demand for electricity on time of day and month. By doing so, our purpose is not to accurately predict the dependent variables but rather to capture the seasonal and daily movements of electricity produced from renewable source and demand in order to give the model a more realistic backdrop. One factor to keep in mind when simulating hourly trade decisions between the UK and France is that these countries are in different time zones. In fact, this is interesting from a trade analysis perspective as, e.g., shifting the lunch and dinner time peaks by one hour is a way by which electricity demand in the two countries is "de-correlated" and increases possibilities for gains from trade.

When deciding how to translate other pieces of data reflecting the Britain and French context and incorporating them in the set parameters of the model, we have to emphasize that we evaluate gains from electricity trade by comparing total welfare under trade between these two countries and total welfare under no trade. However, this estimate must be taken only as an initial estimate that will be made more accurate as richer and more realistic data get incorporated in the model. In particular, given the reality of the electricity trade between the UK and the rest of Europe, as described in Section 2, our framework should be generalized from one to several interconnectors and account for the fact that the electricity markets of Northern Ireland and the Republic of Ireland are fully integrated. Concentrating however on the French-British trade allows us to get a lower bound of the UK’s stake in trading its electricity within the IEM.[30] Let us now discuss in turn the data sources, the way we

[30] This work thus suggests that an approach that combines calibration of a theoretical model and its simulation might prove useful to explore relevant policy questions concerning a given sector (see also Geske et al., 2019).

categorize the electricity production technologies and set some other important parameters of the model, the regressions we use to capture the monthly and hourly patterns of demand and renewable electricity generation, and the simulation results that help us provide answers to the questions posed above.

Our main source of data is the website *gridwatch.templar.co.uk*, which offers free data sets of electricity demand and generation from different sources for the British and French electricity networks. Their source of data, in turn, is the French TSO *RTE France* for the French data and *Elexon*, the provider of the "Balancing and Settlement Code", for the UK supplemented by live data from the University of Sheffield for data on solar power generation. For the UK, data are available in 5-minute intervals while for France they are available in 15-minute intervals. Even though data are available going back as far as 2009 for the UK and 2014 for France, we decided to confine ourselves to 2016 data. This way, we avoid dealing with macro trends for demand and get a consistent view on a recent set of plants, while retaining a sufficiently large number of observations, more specifically, over 35,000 for France and over 100,000 for the UK, to get reliable demand estimates.

For each point in time, the data set provides information on demand and contribution of different electricity sources and interconnectors, which can be positive or negative, as well as the frequency in the grid. For France, the data set reports electricity production from oil, coal, gas, nuclear, wind, solar, hydro, pumped storage, and biomass. It also provides in/out flows from/to Germany, England, Belgium, Spain, Italy, and Switzerland. For the UK, the data set reports production from coal, nuclear, combined cycle gas turbines (CCGT), wind, pumped, hydro, oil, open cycle gas turbines (OCGT), solar and others, as well as in/out flows from/to France, the Netherlands, the East-West Interconnector (between Britain and Ireland), and the Irish interconnector (Northern Ireland-Republic of Ireland). The calibration of the theoretical model requires two steps to which we turn next. First, we need to categorize each sort of electricity into the three technologies assumed in the model, namely, renewable, base-load, and peak-load. Second, we need to characterize the patterns of renewable energy and demand in the UK and France.

Given the different technologies, we categorize all renewable, low marginal cost sources, namely, wind, solar, hydro, pumped, and, in the case of France, biomass as renewables in the sense of our model. In fact, electricity in pumped storage is technically not renewable as in this case it is water that is pumped into reservoirs at times of excess electricity and used to produce hydroelectricity in times of scarcity. As such, we would expect it to be countercyclical and to move against other sources of renewable energy. Table A.4 reports the correlation coefficients between different kinds of renewable energy and pumped energy production levels in the energy mix of the UK and France as observed in the data. Given that the correlation between the supply of pumped energy and other types of technologies is positive, with the exception of wind energy in France, we decide to aggregate pumped energy into the renewable energy category.

An important issue is how to categorize the other fuel-based technologies. While nuclear is a clear candidate for base-load, due to its lumpiness, high start-up costs, and low per-unit costs, some large and efficient coal power plants run permanently as part of the base-load electricity mix as well. This is a problem of aggregation in the data, as they do not allow us to distinguish between large and small plants. We tackle this problem by examining the variation of the electricity produced from each of the non-renewable sources. Figures A.1 through A.8 show the fluctuation in the generation of electricity from each of these sources in five-minute intervals for the UK and in fifteen-minute intervals for France. The examination of these data leads us to decide to classify only nuclear as base-load and all other sources of electricity as peak-load technology because of their very reactive and variable production throughout the year. For example, for the French time series, the overall standard deviation of nuclear electricity generation is 7,033 MWh relative to a mean of 43,475, while coal and gas have standard deviations close to 728 MWh relative to a mean of 813 MWh and 2,404 MWh relative to a mean of 4,074 MWh respectively. The UK time series exhibits similar dispersion features.

Indeed, a first look at Figures A.1-A.8 suggests that the similarity in shape between the fossil technologies and the nuclear electricity doesn't justify classifying anything as base-load apart from nuclear, even though it should be noted that, e.g., the contribution of French gas in winter and fall (the first and last periods) almost never falls below 2,000 MWh as can be seen from Figure A.7. Note that the one-day figures are almost stacked on top of each other so that intra-day variations become very apparent. Figures A.3 and A.4 show that in the UK CCGT generation is typically in the 10-20,000 MWh levels while OCGT generation is negligibly small in the vicinity of 0-200 MWh.

Instead of relying on data from separate sources on theoretically installed capacity, we set the maximum capacity of nuclear power for each country simply equal to the observed maximum in the data set. These maxima are given by 8,868 MWh and 59,289 MWh for France and the UK respectively. We then divide these maxima by the number of nuclear reactors obtained from the World Nuclear Association, namely, 15 for the UK and 58 for France, to obtain the value of the electricity generation per base-load (nuclear) plant, α, as 592 MWh for the UK and 1,022 MWh for France.[31] For the number of base-load plants N, we set it to 15 for the UK and 58 for France. Consequently, the full base-load capacity in our simulation is 8,880 for the UK and 59,276 for France. The interconnector linking the UK and France is assumed to have a capacity Q_K of 2,000 MWh, a volume corresponding to most observations of electricity transmitted over it.

For the capacity of peak-load, $\bar{Q}_{pl}$, one could simply take the maximum production for each of the technologies defined as peak-load and add them up. This would yield values of 43,926 MWh for the UK and 15,294 MWh for France. Using these figures, there would not be a single hour where demand exceeds capacity. However, this would lead to errors if we don't take into account the electricity flows from other interconnectors and other sources, that is, the whole information in the data set. It would be akin to over-fitting our model to the part of the data that is closely represented in the model while ignoring important complementary information that is less relevant to the model. Also, we have to consider the fact that in the data set some demand spikes are extremely high and exceed the highest observed levels generation at any point. These few demand peaks are mitigated in the linear regressions we perform. Since we are more interested in the effect of trade on welfare, and that mostly means

[31] Information retrieved from the UK and France profiles as published in the Website of the World Nuclear Association (https://www.world-nuclear.org/information-library/country-profiles.aspx) on July 30, 2019.

prices, we will use the peak-load capacity to fine-tune the model to different numbers of blackouts.

We ask how many periods there are in the data where demand exceeds domestic electricity generation and how many periods are there when demand exceeds domestic electricity generation plus imports from the other country. In the data set, electricity demand is higher than production plus imports in 4,392 out of 35,067 periods in France and 71,277 out of 104,859 periods in the UK. Especially for the UK, but also for France, these numbers are very high if they were interpreted as on-peak periods. If this information were accurate, it would mean that there were 1,098 on-peak hours in France and 5,939.75 in the UK out of a total of 8,784 hours in 2016. As this seems to overestimate the number of on-peak periods and hence the effects of trade, we adjust the capacity for the peak-load technology to directly determine how many periods with blackout there would be without trade. We vary the number over a conservative range of scenarios that remain below the number of implied on-peak periods in the data. Since the base-load capacity, renewable production, and demand are known at this stage, we can adjust peak-load capacity to the effect we want. We chose the high values taken from the data, namely, 15,294 MWh and 43,926 MWh, as upper limits and then vary through lower values that consecutively give us higher numbers of blackouts.

The prices cannot be directly observed from our data set. As mentioned earlier, the UK is a big net importer of electricity and this strongly suggests that costs are higher in the UK than in France. There is scant information about the short-run marginal costs for different energy sources in each country. Most data sources report levelized cost of electricity (LCOE), a measure that takes into account capital costs and describes the minimum price at which electricity has to sell for a plant to break-even over its lifetime. This measure is useful for decision makers who have to decide whether investing in capacity of a certain technology will be profitable. It is less relevant to a bidder deciding at which market price to operate a plant. The World Nuclear Association (2018) suggests that the UK generally faces higher generation costs than France for all technologies. However, it is not clear if that only includes capital costs or also fuel costs. The International Energy Agency (2010) provides information only from 2010 and fails to deliver much information on the UK. In contrast, it provides information on fuel cost for France that is also given by the World Nuclear Association and on the general pattern of trade with the UK being a big importer.

These different sources of information suggest that in the UK costs are slightly higher than in France. This led us to choosing base-load per unit cost, c_{bl}, of 12.4667 €/MWh for France in 2010.[32] For the UK, we added 5% in the baseline model and used then the figure of 13.09 €/MWh. We set fuel costs for renewables, c_{rw}, to zero even though this is not entirely accurate for biomass as for the latter the cost is much smaller than for wind and solar. As to peak-load technologies, since they seem to be used at the same time, we set their cost, c_{pl}, using the reported cost of gas fueled electricity generation, which averages at about 60 €/MWh for CCGT in the European countries. We therefore set the cost of peak-load at

[32] This figure is for 2010. Thus, given that our analysis is for 2016, an issue that we should have dealt with is the effect of inflation. However, we refrained from adjusting for price changes as the GDP deflator might not accurately reflect changes in natural gas and uranium prices and commodity price changes may or may not accurately represent fuel prices that plant owners face.

60 €/MWh for France and 63 €/MWh, again assuming the 5% cost gap between the UK and France.

Actual demand for electricity depends on the seasons and the daily life of consumers. Electricity demand is clearly relatively higher in the evening and around noon and in the cold seasons. Figures A.9 and A.10 illustrates the patterns of electricity demand in the first week of January for the UK and France. One way to extract these patterns is to run regressions of demand on dummy variables representing each hour of the day and each month. The same is true for renewable energy generation. For country $i \epsilon \{UK, FR\}$ and its corresponding couple of data samples $\{D_t^i\}_{t=1,\cdots,T}$ and $\{RW_t^i\}_{t=1,\cdots,T}$, where D_t^i and RW_t^i are respectively country i's electricity demand and renewable source electricity generation in observation t, we specify an econometric equation of the form

$$Y_t^i = \alpha^i + \sum_{h=2}^{24} \beta_h^i Hour_{ht}^i + \sum_{m=2}^{12} \gamma_m^i Month_{mt}^i + \varepsilon_t \quad (16)$$

where, neglecting the observation index t, Y^i represents either country i's total electricity demand, D^i, or renewable source electricity generation, RW^i, $Hour_h^i$, $h = 2, 3, \cdots, 24$ are dichotomous dummy variables representing the hour spans $1{:}00am - 1{:}59am, 2{:}00am - 2{:}59am, \cdots, 11{:}00pm - 11{:}59pm$, and $Month_m^i$, $m = 2, 3, \cdots, 12$ are dichotomous dummy variables corresponding to the months February, March, …, December.[33]

In the estimation, we adjusted all French time stamps by one hour to account for the fact that the UK and France are in different time zones. Tables A.5 through A.8 show the results of regressing hourly electricity demand and renewable source electricity generation on hour and month dummies for the UK and France. As expected, the estimation results are satisfactory. In the demand equation for the UK, out of the 35 coefficients associated with the hour and month dummies, all but the one of $Hour_2^{UK}$, i.e., the hour $1{:}00am - 1{:}59am$ are significant at a 5% level. In this country's renewable source electricity generation, out of the 35 coefficients, all but the ones of $Hour_2^{UK}$, $Hour_3^{UK}$, $Hour_4^{UK}$, $Hour_5^{UK}$, and $Hour_6^{UK}$, i.e., respectively, the hours $1{:}00am - 1{:}59am$, $2{:}00am - 2{:}59am$, $3{:}00am - 3{:}59am$, $4{:}00am - 4{:}59am$, and $5{:}00am - 5{:}59am$ are significant. As to the regressions concerning France, in both regressions all the 35 coefficients associated with the hour and month dummies are significant a 5% level.[34]

We have seen in the numerical example presented in the previous section that the main effect of trade in the model is a shift in welfare from producers to consumers. As a base-case, we set peak-load capacity very high so that we observe no blackouts before trade. Then, we consider 10 cases where we reduce the capacity in France, 10 cases where we reduce the capacity in the UK, and 10 cases where we simultaneously reduce the capacity in both

[33] The baseline hour and month are $Hour_{1t}^i$ and $Month_{1t}^i$ respectively corresponding to the hour $00{:}00am - 00{:}59am$ and the month of January. The dichotomous variable $Hour_{ht}^i$, $h = 2, 3, \cdots, 24$, takes on the value 1 if the observation t is in the hour h and 0 if it is in any of the other hours of the day. Similarly, the variable $Month_{mt}^i$, $m = 2, 3, \cdots, 12$ takes on the value 1 if the observation t is in the month m and 0 if it is in any of the other months of the year.

[34] We should add that a visual comparison of the actual demand in the first week of 2016 given in Figures A.9 and A.10 and the predicted values from the fitted regressions shown in Figures A.11 and A.12 shows that the model fits the patterns well.

countries. Each step will be just large enough to satisfy electricity demand in one less state of the world, each state of the world occurring 28 to 31 times since it is determined by hour of the day and month.

Now, to answer our original question, i.e., what the value to the UK of its membership in the IEM is, we first take the difference between the mean of total welfare per period before and after trade to obtain the average welfare improvement per hour brought by trade and then scale it to the length of the year by multiplying it by 8,784 in a leap year like 2016 and by 8,760 in a regular year. Table 5 gives the results. Each cell of this table reports the increase of total welfare in the UK following trade in 30 scenarios. As indicated, each scenario corresponds to a combination of one of 10 numbers (0 through 9) of partial blackouts no-trade (benchmark) situation and one of three cases, namely, the case in which we adjust UK's peak-load capacity only to induce between 0 and 9 hour/month-combinations with on-peak prices under autarky, the case in which we only adjust France's peak-load capacity, and the case in which we adjust both UK's and France's capacities.

Table 5 - UK gains from trade[+]

Peak-load K adjust # of partial blackouts (autarky)	UK only	France only	UK and France simultaneously
0	2,310,480.82	2,310,480.82	2,310,480.82
1	2,522,997.76	2,124,502.53	2,337,019.47
2	2,681,862.92	1,969,999.75	2,341,381.86
3	50,375,371.16	1,796,683.38	49,861,573.71
4	177,963,781.74	1,613,500.74	177,266,801.65
5	268,715,312.37	1,440,906.66	267,845,738.21
6	288,605,702.78	1,305,498.66	287,713,612.09
7	446,553,135.46	1,311,667.78	445,687,208.89
8	521,680,666.65	1,443,727.78	520,949,683.08
9	634,157,471.71	1,459,723.78	914,559,269.97

[+] Units are 2016 €.

We see from Table 5 that for the UK, when we vary the number of national capacity shortages from 0 to 9, the gains from trade increases by 634,157,471.71 €. In the case of the simultaneously varied peak-load capacity, gains from trade go up to 914,559,269.97 €. In the case where the UK can always nationally satisfy its electricity demand, but France cannot, total welfare gains through trading for the UK go only as high as 1,459,723.78 €. This is consistent with the observation that gains from trade occur largely to consumers. Figures A.13, A.16, and A.19 report the percent change in total surplus for each country from introducing trade as a function of the number of partial blackouts that would happen without trade.[35] Figures A.14, A.15, A.17, A.18, A.20, and A.21 show the percentage change in consumer and producer surplus for the UK and France in the three situations. Notably, the decrease in producer surplus after trade is relatively high, e.g., between 40 and 60% for the UK in the scenario where UK capacity is adjusted (see Figure A.15). In one scenario, the

[35] As an illustration, at the point $(x, y) = (3, 0.91044)$ of the red line in Figure A.14, the UK sees its consumer surplus increase by 0.9% through trade when its peak-load capacity is sufficient to cover all but the three states of the world with the highest demand.

decrease is even greater than 80 %. The change in consumer welfare after trade is much smaller because consumer surplus in most periods is much closer to the value of $VoLL$, set at 20,000 €, which is much lower than production cost. For example, as can be seen in Figure A.20, the increase in consumer surplus in the scenario where capacity in both countries is simultaneously adjusted remains below 4 %. Still, the overall effect of trade on total surplus is positive in any case. In a nutshell, assuming that trade alleviates scarcity in some high-demand periods in the UK, a reasonable ballpark estimate of the gains from electricity trade for the UK is in the range of 600 M€ - 900 M€.

5. Conclusion

This article introduces a model of an electricity market with peak-load pricing, inelastic demand, and perfect competition to study through simulations the welfare effect of trade between two countries. Under some assumptions on willingness-to-pay and other key parameters of the model, we find that producers make inframarginal and scarcity rents, but that trade diminishes them whenever it becomes pivotal in the price determination process or alleviates scarcity. As a result, gains from trade largely accrue to consumers. The model is then calibrated to data on the UK and France and simulated to estimate the value of the European IEM for the UK. We find that the answer depends on how many hours there are during which trade alleviates scarcity in the UK, which is an electricity importer as often as it nationally faces excess demand given its production capacity. Letting the number of states of the world in which there is excess demand vary between 0 and 9, or roughly from 0 to 270 peak hours, the annual gains from trade are in the 0-175 M€ range at 4 states of the world with excess demand to well over 900 M€ in the case of 9 states of the world where demand exceeds capacity in both France and the UK. While these figures are instructive, they should be taken with caution for at least the following reasons.

First, we assume inelastic demand yet, even though private consumers may not react to daily changes in price, large industrial consumers might realistically do. While under inelastic demand lower prices do not increase the quantity traded and, thus, most gains from trade occur when imports alleviate a capacity shortage, introducing elastic demand would increase welfare gains whenever trade decreases price in the importing country. Second, in our model consumer surplus depends on wholesale prices whereas in reality many consumers pay fixed/flat rates for electricity. Two factors however speak in favor of our assumption. One can think of electricity retail companies and final consumers as one economic agent, focusing on the final consumer benefit from using electricity and the retailer's cost of purchasing it and regarding the retail price scheme as a transfer between the two that should not impact the total consumer welfare under efficient contracting. More importantly, retail prices paid by consumers should reflect wholesale prices at large provided that the retail market for electricity is competitive. In such circumstances, retailers should on average break even and thus if international trade lowers wholesale prices, these price drops should be passed on to prices paid by consumers.

Despite these caveats, this article has presented a useful tool for policy analysis that is also open to extensions. The possibility to assign environmental costs to peak-load production is certainly a promising avenue of future research. Future research could also explore the beneficial effects of changing the dispatch plan at the second stage of this model, thus emulating a truly integrated European market where all electricity-generating assets are used most efficiently to satisfy aggregate demand instead of just realizing trade opportunities after each market has cleared. This could lead to a better utilization rate of cheaper and less flexible nuclear plants as well as a reduction from fossil fuel plants' pollution. An extension to trade among more than two countries would also be a natural extension that could increase the accuracy of the model. Additionally, loop-flow considerations that are an important issue in Europe would need to be taken into account. Nevertheless, in spite of these open flanks and qualifications, the model can serve as a stepping-stone towards the study of market coupling.

Appendix - Tables and Figures

Table A.1 - Simulation results

Statistic	D^A	D^B	Q^A_{rw}	Q^B_{rw}	Q^A_{bl}
Min.	1,315	1,212	0.0004	0.0004	1,000
1st Qu.	2,497	2,497	99.9046	100.5058	2,250
Median	2,700	2,700	200.0305	200.2806	2,500
Mean	2,700	2,700	200.0191	200.1716	2,375
3rd Qu.	2,903	2,902	300.1887	299.9114	2,500
Max.	4,375	4,158	399.9993	399.9998	2,500

Statistic	Q^B_{bl}	Q^A_{pl}	Q^B_{pl}	Q^A	Q^B
Min.	1,000	0.00	0.00	1,333	1,249
1st Qu.	2,250	0.00	0.00	2,538	2,535
Median	2,500	0.00	82.91	2,724	2,739
Mean	2,375	93.59	131.50	2,713	2,719
3rd Qu.	2,500	158.22	215.28	2,909	2,925
Max.	2,500	500.00	500.00	3,400	3,400

Statistic	P^A	P^B	CS^A	CS^B	PS^A
Min.	1.100	1.000	0	0	-136.3
1st Qu.	1.100	1.000	20,216	20,644	368.3
Median	2.200	2.000	21,884	22,342	2,890.5
Mean	2.168	2.004	20,909	21,349	3,123.9
3rd Qu.	2.200	2.000	23,143	23,620	3,179.7
Max.	10.00	10.00	27,267	27,788	30,108.7

Statistic	PS^B	TS^A	TS^B	$Import^A$	$Import^B$
Min.	-123.5	11,915	11,097	0.00	0.0
1st Qu.	370.7	22,398	22,702	0.00	0.0
Median	2,673.5	24,164	24,463	36.43	0.0
Mean	2,983.2	24,033	24,332	45.03	12.6
3rd Qu.	2,949.0	25,840	26,135	100.00	0.0
Max.	30,459.4	30,852	31,193	100.00	100.0

Statistic	V^A	V^B	pv^A	pv^B	$bmCS^A$
Min.	0.00	0.00	1.100	1.000	0
1st Qu.	65.45	65.61	1.100	1.000	20,002
Median	240.52	240.61	2.200	2.000	21,747
Mean	238.36	238.52	4.294	4.099	20,318
3rd Qu.	411.14	411.17	2.200	2.000	23,010
Max.	500.00	500.00	42.000	42.000	26,498

Statistic	$bmCS^B$	$bmPS^A$	$bmPS^B$	$bmTS^A$	$bmTS^B$
Min.	0	-136.3	-124.1	11,915	11,097
1st Qu.	20,426	297.2	266.3	22,349	22,588
Median	22,209	2,892.3	2,627.7	24,129	24,387
Mean	20,767	3,671.9	3,484.6	23,990	24,251
3rd Qu.	23,490	3,186.6	2,894.0	25,815	26,097
Max.	27,188	30,108.7	30,459.9	30,109	30,460

Statistic	bmP^A	bmP^B	$Shortfall^A$	$Shortfall^A$	n^A_{bl}
Min.	1.100	1.000	0.00	0.000	3.00
1st Qu.	1.100	1.000	0.00	0.000	9.00
Median	2.200	2.000	0.00	0.000	10.00
Mean	2.355	2.188	8.29	8.204	9.21
3rd Qu.	2.200	2.000	0.00	0.000	10.00
Max.	10.000	10.000	1,185.30	950.623	10.00

Statistic	n^B_{bl}
Min.	3.000
1st Qu.	9.000
Median	9.000
Mean	9.209
3rd Qu.	10.000
Max.	10.000

Table A.2 - Blackout occurrence

Occurrence	$Blackout^A$	$Blackout^B$	$bmBlackout^A$	$bmBlackout^B$
Yes	36,716	36,352	60,603	59,733
No	963,284	963,648	939,397	940,267
Total	1000,000	1000,000	1000,000	1000,000

Table A.3 - Cross-distribution of countries' prices

Country B Country A	1	2	2.2	10	Total
1.1	84,000	192,873	0	12,368	289,241
2.2	193,685	441,642	18,322	20,394	674,043
10	12,302	20,824	0	3,590	36,716
Total	289,987	655,339	18,322	36,352	1,000,000

Table A.4 - Correlation between types of energy production levels+

UK

	Wind	Solar	Hydro	Pumped
Wind	1			
Solar	0.08	1		
Hydro	0.32	-0.01	1	
Pumped	0.02	0.06	0.49	1

+ Note that "Biomass" does not appear as an energy category in the UK data.

France

	Wind	Solar	Hydro	Biomass	Pumped
Wind	1				
Solar	-0.14	1			
Hydro	0.02	0.08	1		
Biomass	-0.10	0.06	-0.10	1	
Pumped	-0.10	0.23	0.47	0.02	1

Table A.5- UK electricity demand[+]

Variable	Coefficient	Standard error
Constant	30,531.22*	65.82
$Hour_2^{UK}$ (1:00am-1:59am)	-37.47	77.06
$Hour_3^{UK}$ (2:00am-2:59am)	-593.20*	77.06
$Hour_4^{UK}$ (3:00am-3:59am)	-938.36*	77.16
$Hour_5^{UK}$ (4:00am-4:59am)	-961.60*	77.06
$Hour_6^{UK}$ (5:00am-5:59am)	433.58*	77.04
$Hour_7^{UK}$ (6:00am-6:59am)	3,811.13*	77.04
$Hour_8^{UK}$ (7:00am-7:59am)	7,015.79*	77.05
$Hour_9^{UK}$ (8:00am-8:59am)	8,319.21*	77.00
$Hour_{10}^{UK}$ (9:00am-9:59am)	8,702.65*	76.98
$Hour_{11}^{UK}$ (10:00am-10:59am)	8,615.63*	76.99
$Hour_{12}^{UK}$ (11:00am-11:59am)	8,566.19*	76.96
$Hour_{13}^{UK}$ (12:00am-12:59pm)	8,379.76*	76.94
$Hour_{14}^{UK}$ (1:00pm-1:59pm)	7,853.32*	77.01
$Hour_{15}^{UK}$ (2:00pm-2:59pm)	7,825.18*	77.02
$Hour_{16}^{UK}$ (3:00pm-3:59pm)	8,772.15*	77.08
$Hour_{17}^{UK}$ (4:00pm-4:59pm)	10,729.24*	77.07
$Hour_{18}^{UK}$ (5:00pm-5:59pm)	12,222.64*	77.08
$Hour_{19}^{UK}$ (6:00pm-6:59pm)	12,447.87*	77.00
$Hour_{20}^{UK}$ (7:00pm-7:59pm)	11,629.88*	76.98
$Hour_{21}^{UK}$ (8:00pm-8:59pm)	9,944.52*	77.02
$Hour_{22}^{UK}$ (9:00pm-9:59pm)	7,0755.11*	77.04
$Hour_{23}^{UK}$ (10:00pm-10:59pm)	3,355.18*	77.04
$Hour_{24}^{UK}$ (11:00pm-11:59pm)	583.79*	77.04
$Month_2^{UK}$ (February)	88.53*	55.12
$Month_3^{UK}$ (March)	-1,320.35*	54.19
$Month_4^{UK}$ (April)	-4,528.97*	54.63
$Month_5^{UK}{}_4$ (May)	-7,913.99*	54.19
$Month_6^{UK}$ (June)	-7,453.86*	54.64
$Month_7^{UK}$ (July)	-8,817.02*	54.19
$Month_8^{UK}$ (August)	-9,128.07*	54.19
$Month_9^{UK}$ (September)	-7,411.23*	55.11
$Month_{10}^{UK}$ (October)	-4,041.17*	54.19
$Month_{11}^{UK}$ (November)	639.90*	54.64
$Month_{12}^{UK}$ (December)	-124.40*	54.22
Obs: 104,859		
R^2: 0.72		

[+] Figures are rounded to the second decimal and a "*" indicates significance at a 5% statistical level.

Table A.6 - UK renewable energy generation+

Variable	Coefficient	Standard error
Constant	3,824.94*	27.23
$Hour_2^{UK}$ (1:00am-1:59am)	-32.48	31.88
$Hour_3^{UK}$ (2:00am-2:59am)	-50.66	31.88
$Hour_4^{UK}$ (3:00am-3:59am)	-31.49	31.92
$Hour_5^{UK}$ (4:00am-4:59am)	-19.31	31.88
$Hour_6^{UK}$ (5:00am-5:59am)	13.47	31.87
$Hour_7^{UK}$ (6:00am-6:59am)	281.89*	31.87
$Hour_8^{UK}$ (7:00am-7:59am)	582.38*	31.87
$Hour_9^{UK}$ (8:00am-8:59am)	747.15*	31.85
$Hour_{10}^{UK}$ (9:00am-9:59am)	875.36*	31.85
$Hour_{11}^{UK}$ (10:00am-10:59am)	951.49*	31.85
$Hour_{12}^{UK}$ (11:00am-11:59am)	1,035.04*	31.84
$Hour_{13}^{UK}$ (12:00am-12:59pm)	1,039.95*	31.83
$Hour_{14}^{UK}$ (1:00pm-1:59pm)	991.18*	31.85
$Hour_{15}^{UK}$ (2:00pm-2:59pm)	945.18*	31.86
$Hour_{16}^{UK}$ (3:00pm-3:59pm)	939.59*	31.89
$Hour_{17}^{UK}$ (4:00pm-4:59pm)	1,161.76*	31.88
$Hour_{18}^{UK}$ (5:00pm-5:59pm)	1,446.03*	31.88
$Hour_{19}^{UK}$ (6:00pm-6:59pm)	1,456.59*	31.85
$Hour_{20}^{UK}$ (7:00pm-7:59pm)	1,223.77*	31.85
$Hour_{21}^{UK}$ (8:00pm-8:59pm)	940.51*	31.86
$Hour_{22}^{UK}$ (9:00pm-9:59pm)	685.90*	31.87
$Hour_{23}^{UK}$ (10:00pm-10:59pm)	344.21*	31.87
$Hour_{24}^{UK}$ (11:00pm-11:59pm)	81.96*	31.87
$Month_2^{UK}$ (February)	-459.69*	22.80
$Month_3^{UK}$ (March)	-1,566.40*	22.42
$Month_4^{UK}$ (April)	-1,619.67*	22.60
$Month_5^{UK}$ 4 (May)	-1,841.83*	22.42
$Month_6^{UK}$ (June)	-2,867.49*	22.60
$Month_7^{UK}$ (July)	-2,237.43*	22.42
$Month_8^{UK}$ (August)	-1,933.71*	22.42
$Month_9^{UK}$ (September)	-1,422.34*	22.80
$Month_{10}^{UK}$ (October)	-1,348.58*	22.42
$Month_{11}^{UK}$ (November)	-202.03*	22.60
$Month_{12}^{UK}$ (December)	153.19*	22.43
Obs: 104,859		
R^2: 0.33		

+ Figures are rounded to the second decimal and a "*" indicates significance at a 5% statistical level.

Table A.7 - France electricity demand[+]

Variable	Coefficient	Standard error
Constant	61,999.66*	190.09
$Hour_2^{FR}$ (1:00am-1:59am)	-1,195.15*	222.48
$Hour_3^{FR}$ (2:00am-2:59am)	-3,702.59*	222.48
$Hour_4^{FR}$ (3:00am-3:59am)	-4,886.92*	222.48
$Hour_5^{FR}$ (4:00am-4:59am)	-3,957.79*	222.48
$Hour_6^{FR}$ (5:00am-5:59am)	-834.49*	222.48
$Hour_7^{FR}$ (6:00am-6:59am)	3,148.03*	222.52
$Hour_8^{FR}$ (7:00am-7:59am)	5,512.54*	222.52
$Hour_9^{FR}$ (8:00am-8:59am)	7,374.16*	222.48
$Hour_{10}^{FR}$ (9:00am-9:59am)	8,101.12*	222.48
$Hour_{11}^{FR}$ (10:00am-10:59am)	8,461.65*	222.48
$Hour_{12}^{FR}$ (11:00am-11:59am)	9,147.76*	222.33
$Hour_{13}^{FR}$ (12:00am-12:59pm)	8,420.46*	222.33
$Hour_{14}^{FR}$ (1:00pm-1:59pm)	6,295.27*	222.41
$Hour_{15}^{FR}$ (2:00pm-2:59pm)	4,879.77*	222.33
$Hour_{16}^{FR}$ (3:00pm-3:59pm)	3,803.55*	222.41
$Hour_{17}^{FR}$ (4:00pm-4:59pm)	3758.79*	222.33
$Hour_{18}^{FR}$ (5:00pm-5:59pm)	5,836.87*	222.48
$Hour_{19}^{FR}$ (6:00pm-6:59pm)	8,026.65*	222.33
$Hour_{20}^{FR}$ (7:00pm-7:59pm)	6,508.14*	222.33
$Hour_{21}^{FR}$ (8:00pm-8:59pm)	4,267.90*	222.44
$Hour_{22}^{FR}$ (9:00pm-9:59pm)	3,895.15*	222.48
$Hour_{23}^{FR}$ (10:00pm-10:59pm)	5,887.05*	222.48
$Hour_{24}^{FR}$ (11:00pm-11:59pm)	3,703.46*	222.48
$Month_2^{FR}$ (February)	-666.29*	159.28
$Month_3^{FR}$ (March)	-3,427.96*	156.68
$Month_4^{FR}$ (April)	-12,498.95*	157.93
$Month_5^{FR}{}_4$ (May)	-19,923.79*	156.63
$Month_6^{FR}$ (June)	-21,143.46*	157.92
$Month_7^{FR}$ (July)	-20,998.07*	156.63
$Month_8^{FR}$ (August)	-22.937.64*	156.63
$Month_9^{FR}$ (September)	-19,940.83*	157.92
$Month_{10}^{FR}$ (October)	-14,706.24*	156.60
$Month_{11}^{FR}$ (November)	-5,302.98*	157.93
$Month_{12}^{FR}$ (December)	1,639.76*	156.72
Obs: 35,067		
R^2: 0.73		

[+] Figures are rounded to the second decimal and a "*" indicates significance at a 5% statistical level.

Table A.8 - France renewable energy generation[+]

Variable	Coefficient	Standard error
Constant	7,559.96*	69.70
$Hour_2^{FR}$ (1:00am-1:59am)	-623.70*	81.58
$Hour_3^{FR}$ (2:00am-2:59am)	-1,426.77*	81.58
$Hour_4^{FR}$ (3:00am-3:59am)	-1,814.88*	81.58
$Hour_5^{FR}$ (4:00am-4:59am)	-1,626.46*	81.58
$Hour_6^{FR}$ (5:00am-5:59am)	-367.26*	81.58
$Hour_7^{FR}$ (6:00am-6:59am)	1,760.12*	81.59
$Hour_8^{FR}$ (7:00am-7:59am)	3,209.56*	81.59
$Hour_9^{FR}$ (8:00am-8:59am)	4,427.23*	81.58
$Hour_{10}^{FR}$ (9:00am-9:59am)	5,232.58*	81.58
$Hour_{11}^{FR}$ (10:00am-10:59am)	5,629.24*	81.58
$Hour_{12}^{FR}$ (11:00am-11:59am)	5,863.28*	81.52
$Hour_{13}^{FR}$ (12:00am-12:59pm)	5,541.83*	81.52
$Hour_{14}^{FR}$ (1:00pm-1:59pm)	4,720.57*	81.55
$Hour_{15}^{FR}$ (2:00pm-2:59pm)	3,815.85*	81.52
$Hour_{16}^{FR}$ (3:00pm-3:59pm)	3,220.54*	81.55
$Hour_{17}^{FR}$ (4:00pm-4:59pm)	3,360.57*	81.52
$Hour_{18}^{FR}$ (5:00pm-5:59pm)	4,302.76*	81.58
$Hour_{19}^{FR}$ (6:00pm-6:59pm)	5,292.81*	81.52
$Hour_{20}^{FR}$ (7:00pm-7:59pm)	4,393.87*	81.52
$Hour_{21}^{FR}$ (8:00pm-8:59pm)	3,040.39*	81.56
$Hour_{22}^{FR}$ (9:00pm-9:59pm)	2,502.36*	81.58
$Hour_{23}^{FR}$ (10:00pm-10:59pm)	3,164.47*	81.58
$Hour_{24}^{FR}$ (11:00pm-11:59pm)	1,908.58*	81.58
$Month_2^{FR}$ (February)	2,861.60*	58.41
$Month_3^{FR}$ (March)	1,548.87*	57.45
$Month_4^{FR}$ (April)	1,213.30*	57.91
$Month_5^{FR}{}_4$ (May)	534.98*	57.43
$Month_6^{FR}$ (June)	1,261.40*	57.90
$Month_7^{FR}$ (July)	-974.45*	57.43
$Month_8^{FR}$ (August)	-2,615.64*	57.43
$Month_9^{FR}$ (September)	-3,701.50*	57.90
$Month_{10}^{FR}$ (October)	-4,342.31*	57.41
$Month_{11}^{FR}$ (November)	-1,840.59*	57.91
$Month_{12}^{FR}$ (December)	-2,414.29*	57.47

Obs: 35,067

R^2: 0.69

[+] Figures are rounded to the second decimal and a "*" indicates significance at a 5% statistical level.

Figure A.1 - UK nuclear electricity generation in MWh in 2016 in 5-mn intervals

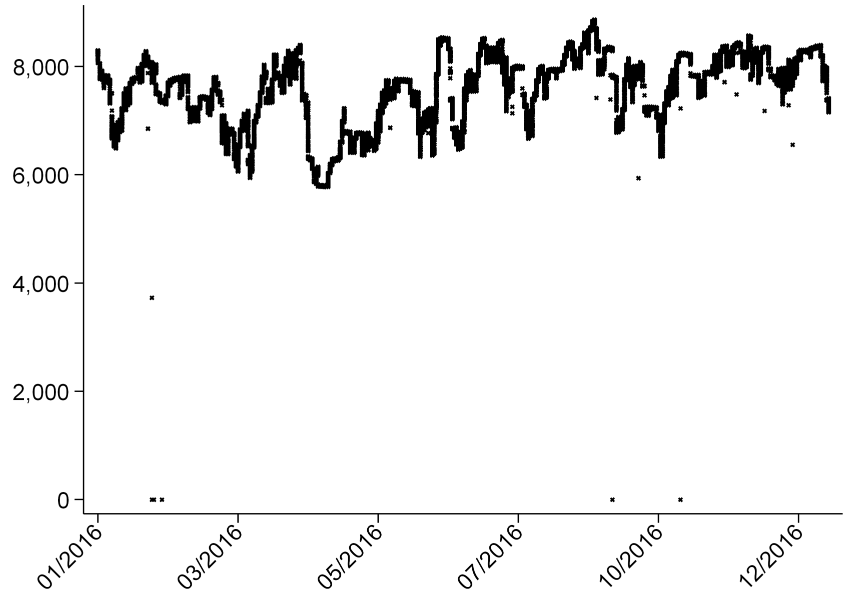


Figure A.2 - UK coal electricity generation in MWh in 2016 in 5-mn intervals

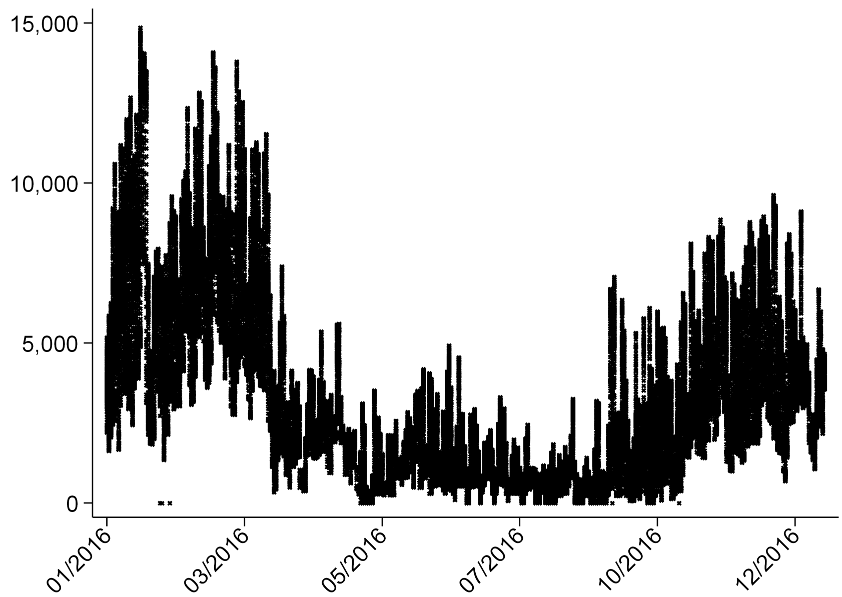


Figure A.3 - UK CCGT electricity generation in MWh in 2016 in 5-mn intervals

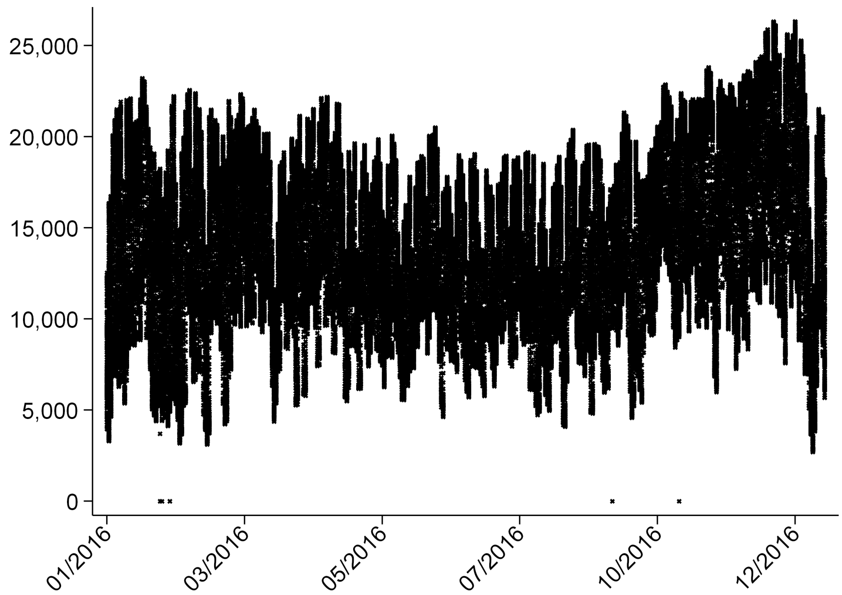


Figure A.4 - UK OCGT electricity generation in MWh in 2016 in 5-mn intervals

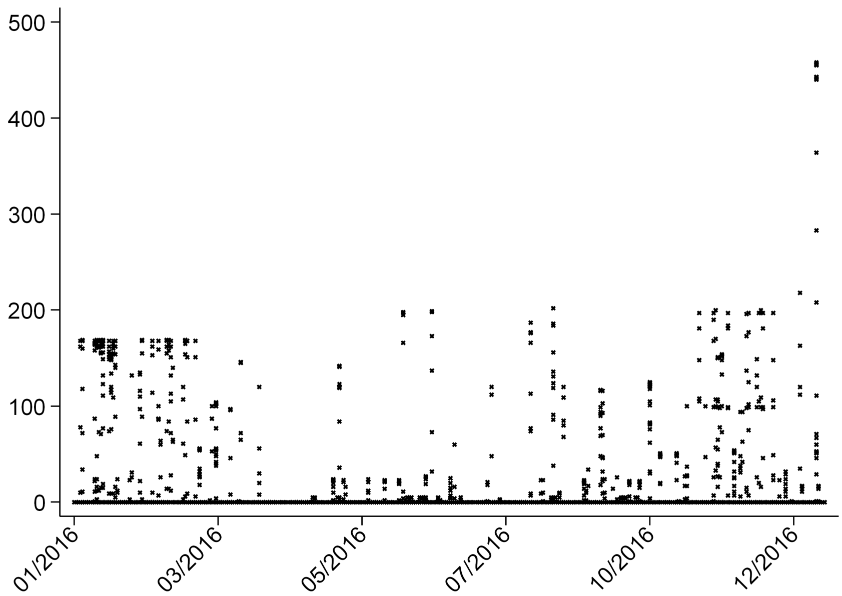


Figure A.5 - France nuclear electricity generation in MWh in 2016 in 15-mn intervals

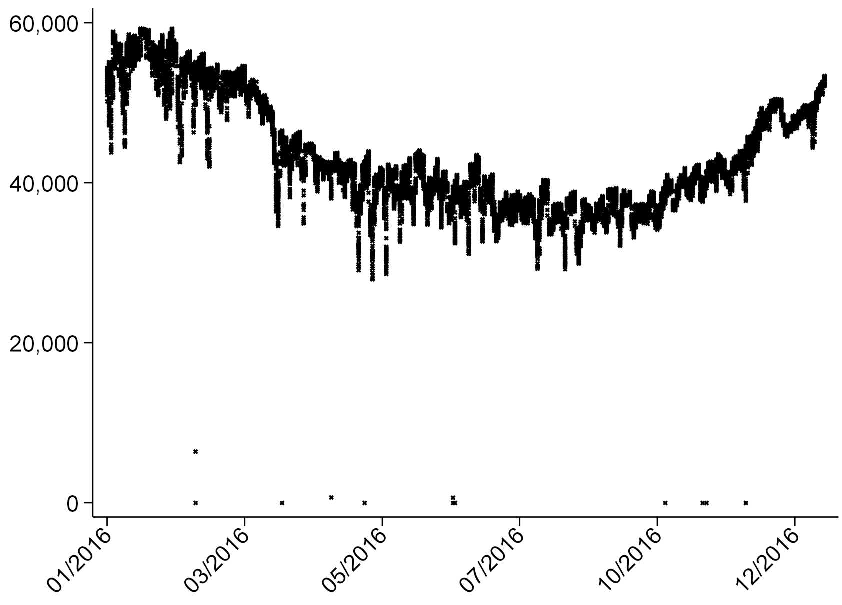


Figure A.6 - France coal electricity generation in MWh in 2016 in 15-mn intervals

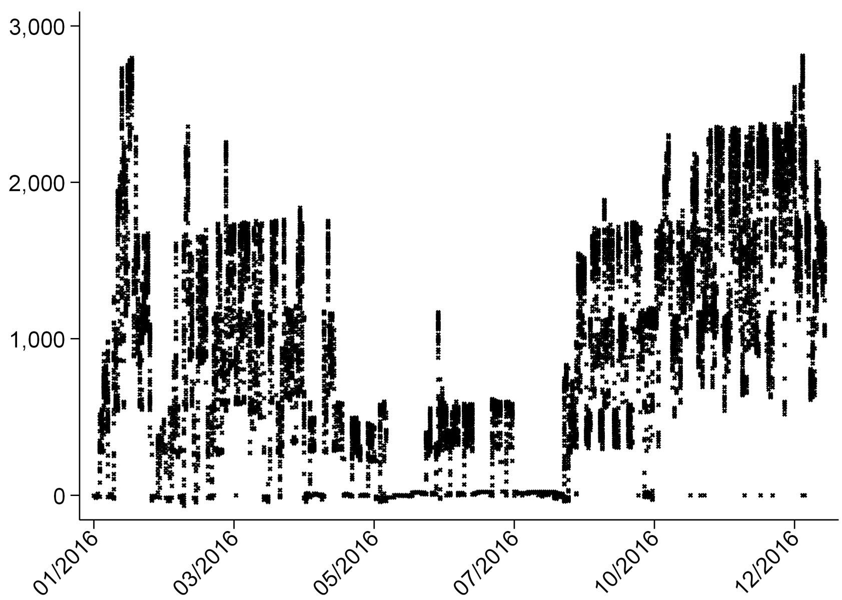


Figure A.7 - France gas electricity generation in MWh in 2016 in 15-mn intervals

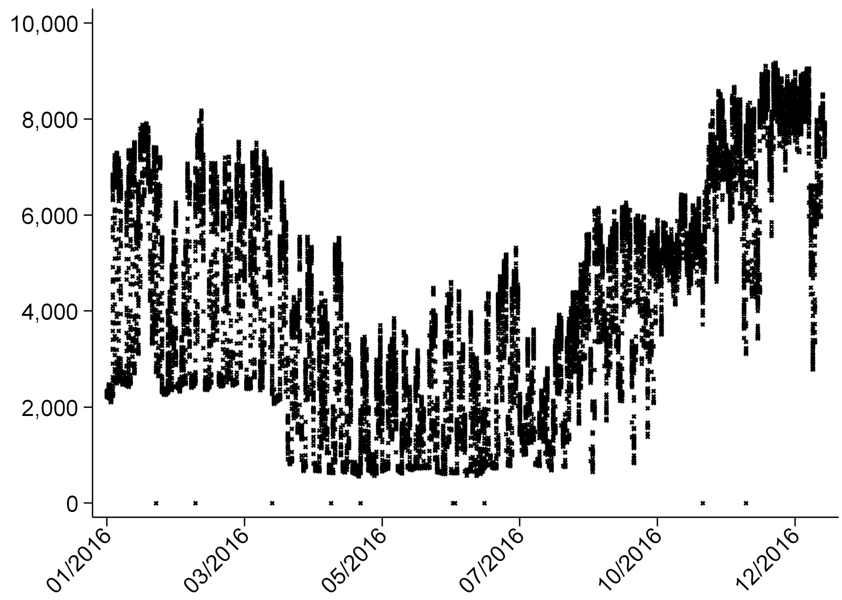


Figure A.8 - France oil electricity generation in MWh in 2016 in 15-mn intervals

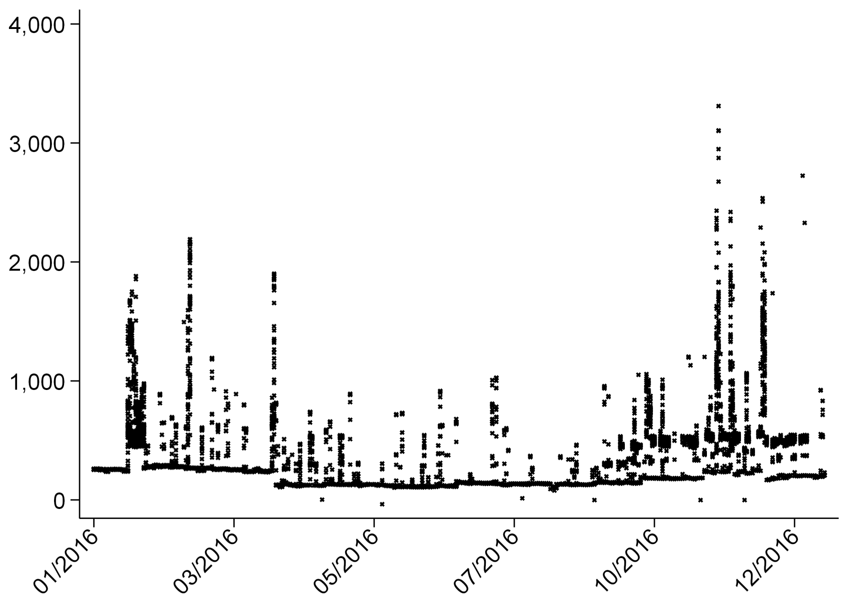


Figure A.9 - UK electricity demand in MWh in the first week of 2016 in 5-mn intervals

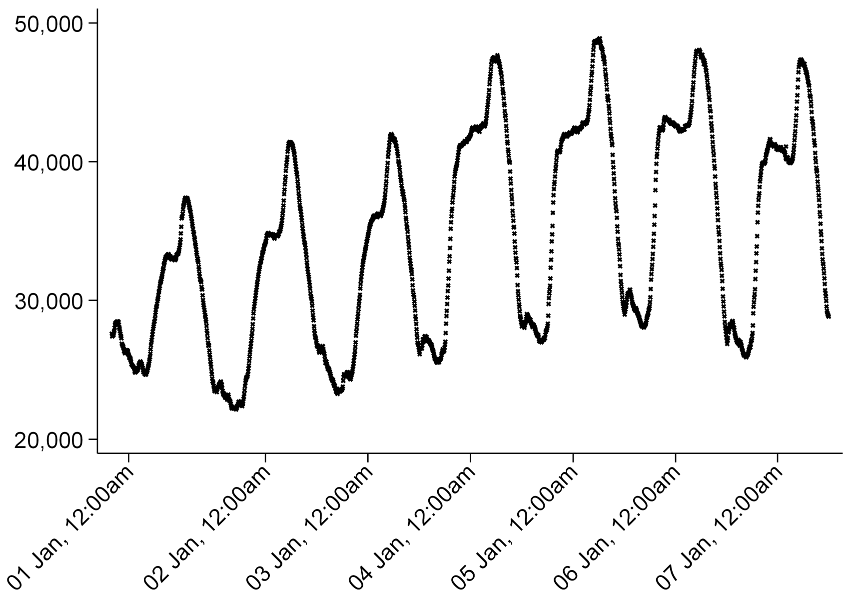


Figure A.10 - France electricity demand in MWh in the first week of 2016 in 15-mn intervals

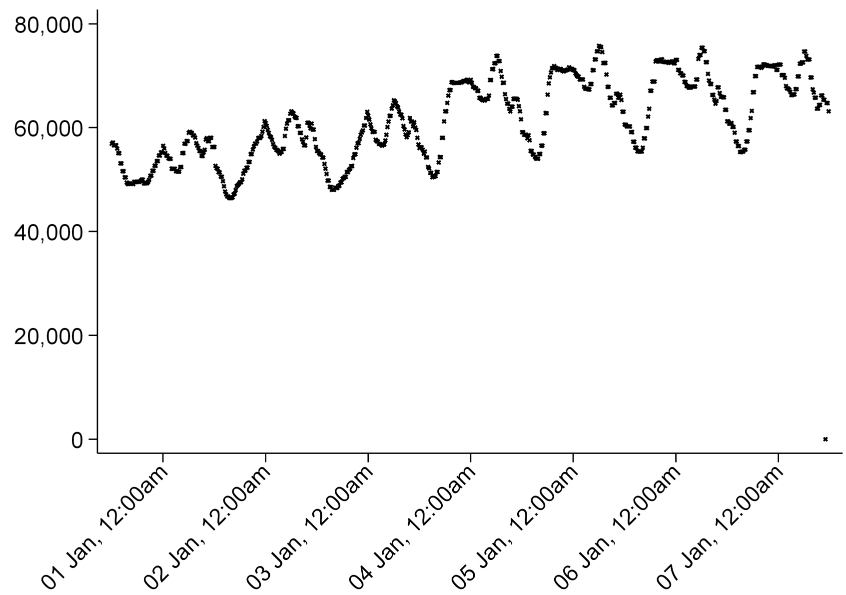


Figure A.11 - Predicted UK electricity demand in MWh in the first week of 2016

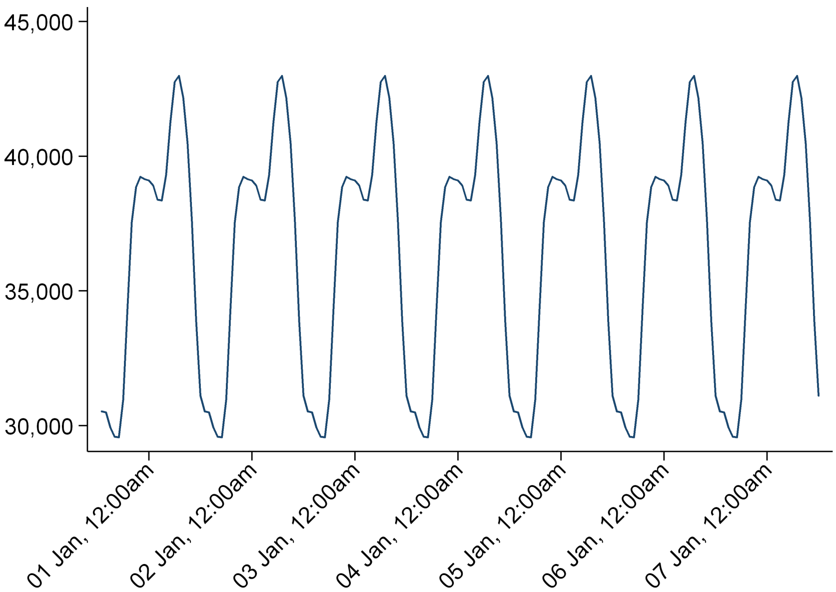


Figure A.12 - Predicted France electricity demand in MWh in the first week of 2016

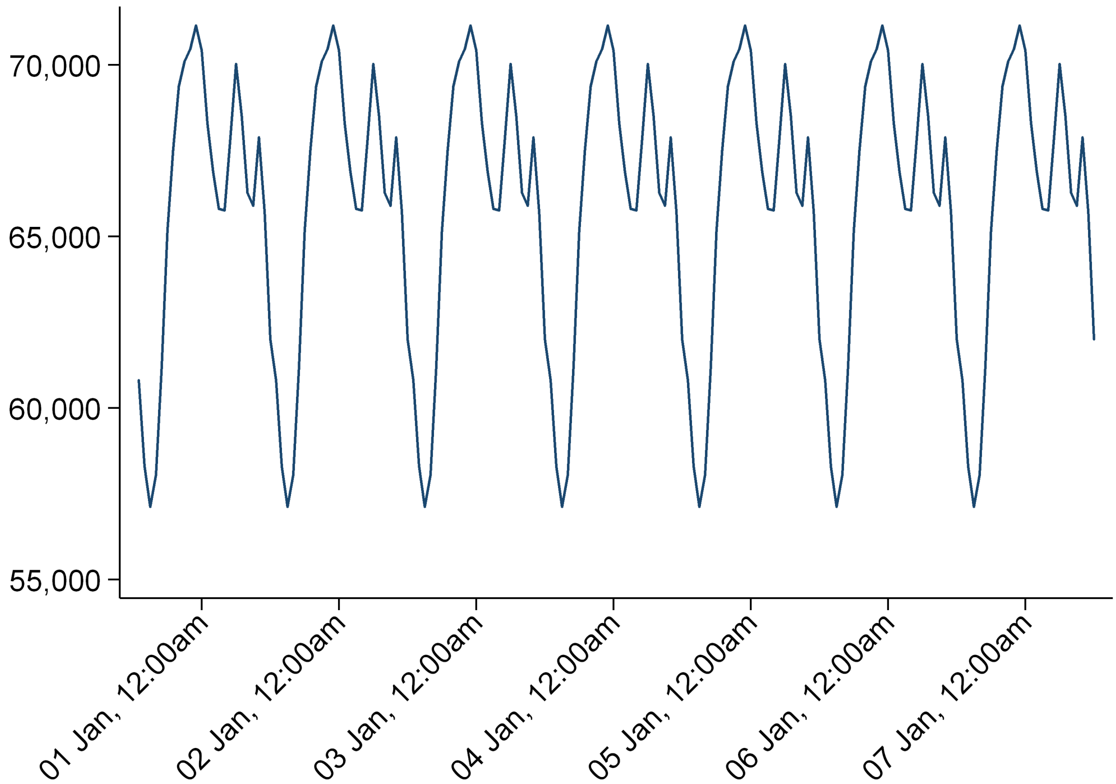


Figure A.13 - UK total surplus gains from trade as the number of peak periods in the UK increases

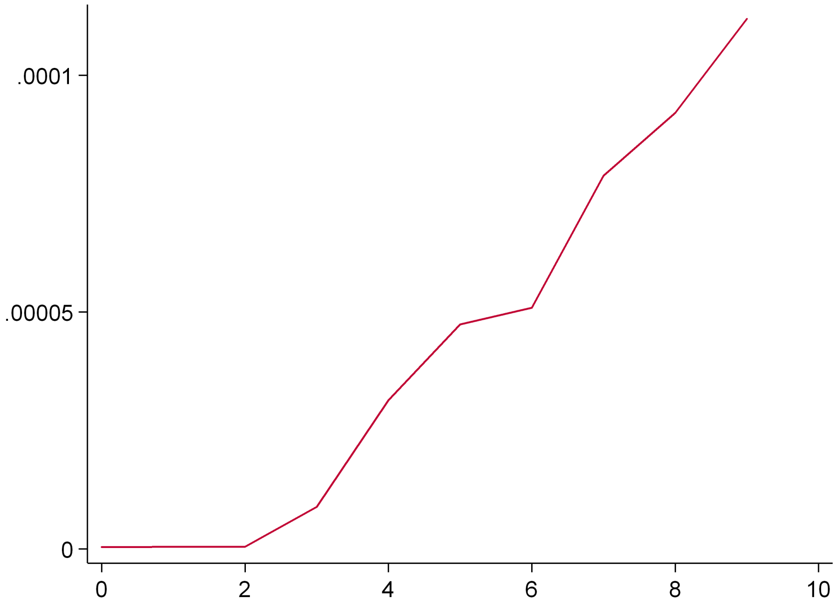


Figure A.14 - UK consumer surplus gains from trade as the number of peak periods in the UK increases

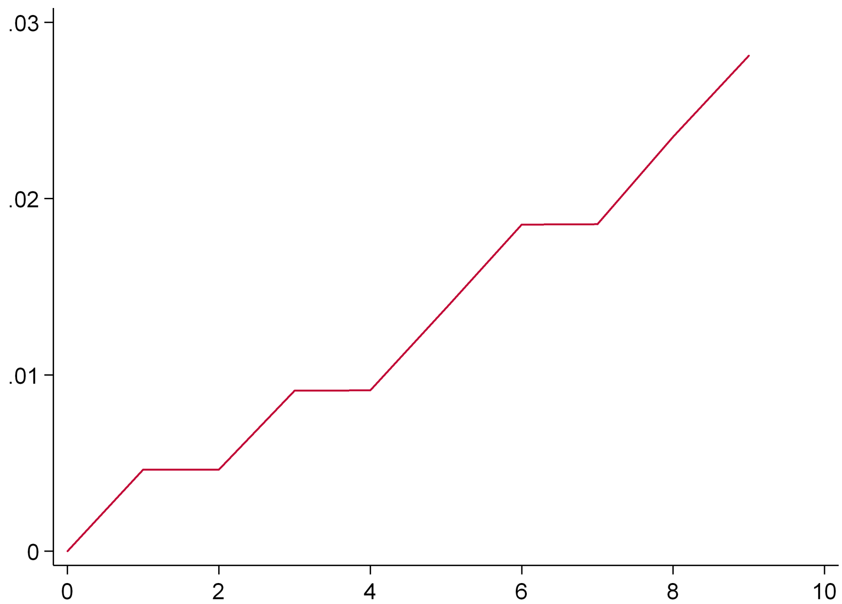


Figure A.15 - UK producer surplus gains from trade as the number of peak periods in the UK increases

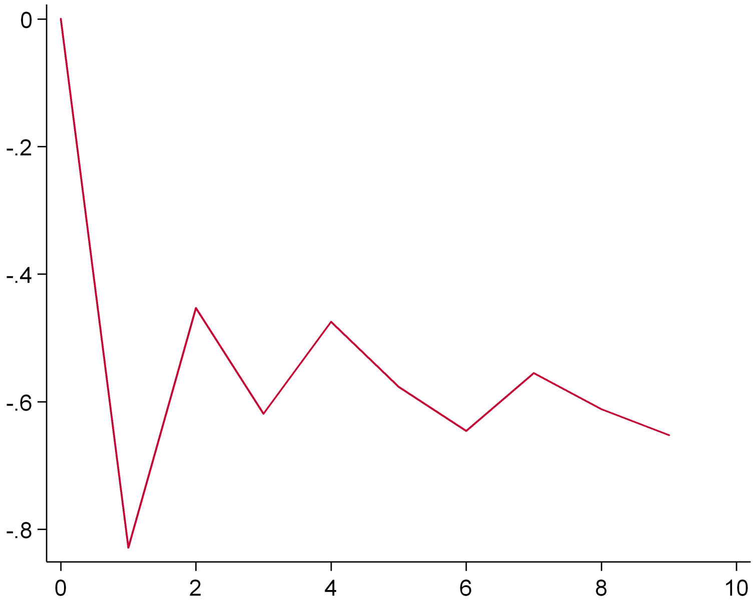


Figure A.16 - France total surplus gains from trade as the number of peak periods in France increases

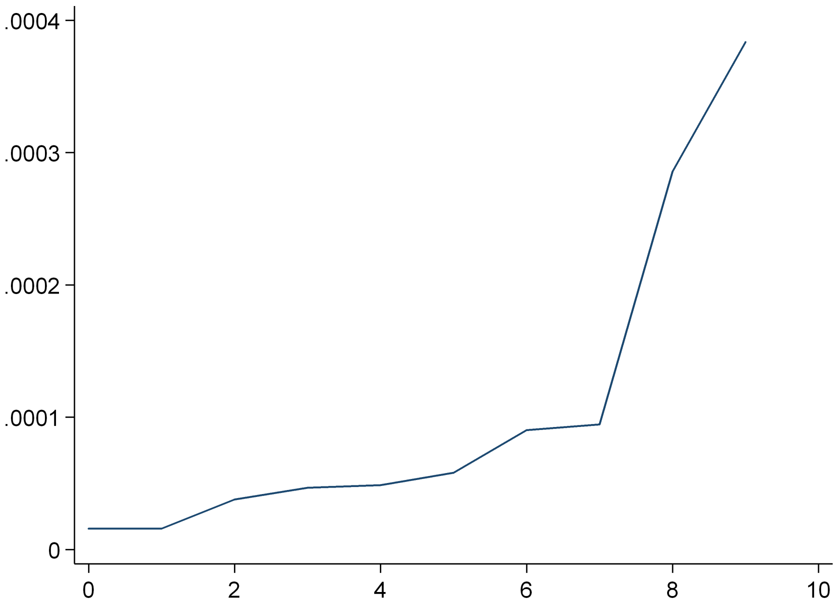


Figure A.17 - France consumer surplus gains from trade as the number of peak periods in France increases

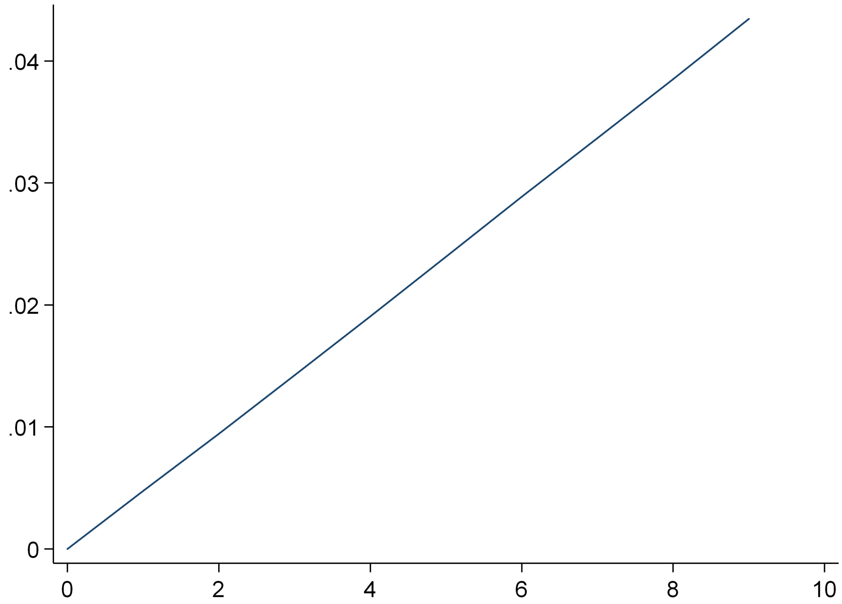


Figure A.18 - France producer surplus gains from trade as the number of peak periods in France increases

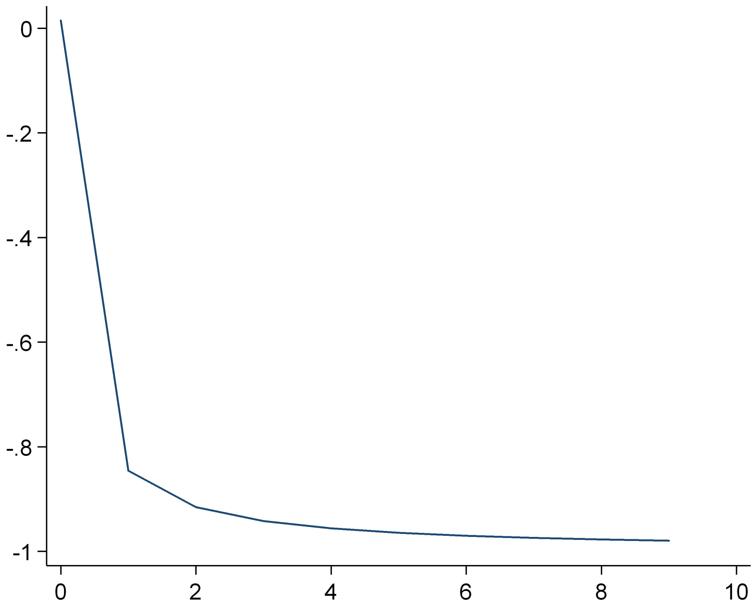


Figure A.19 - UK and France total surplus gains from trade as the number of peak periods in France and the UK increases

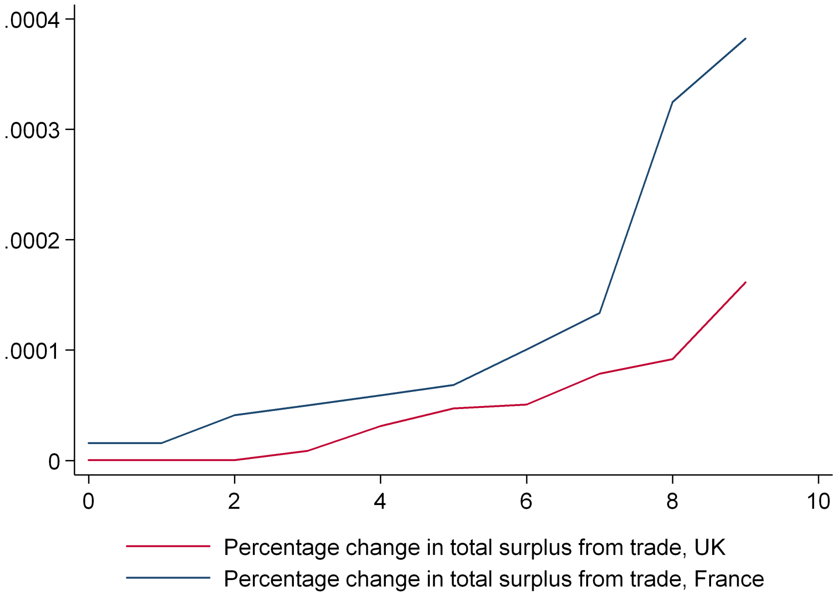


Figure A.20 - UK and France consumer surplus gains from trade as the number of peak periods in France and the UK increases

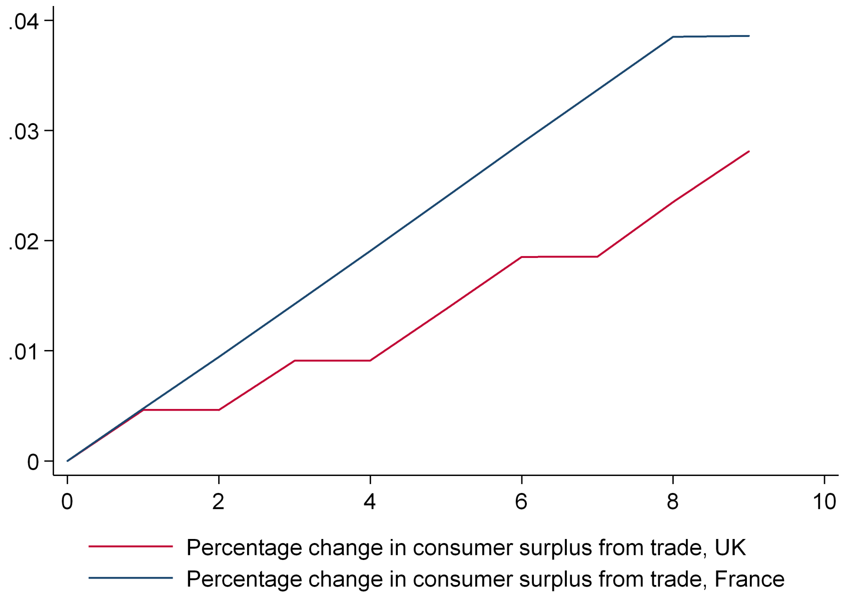
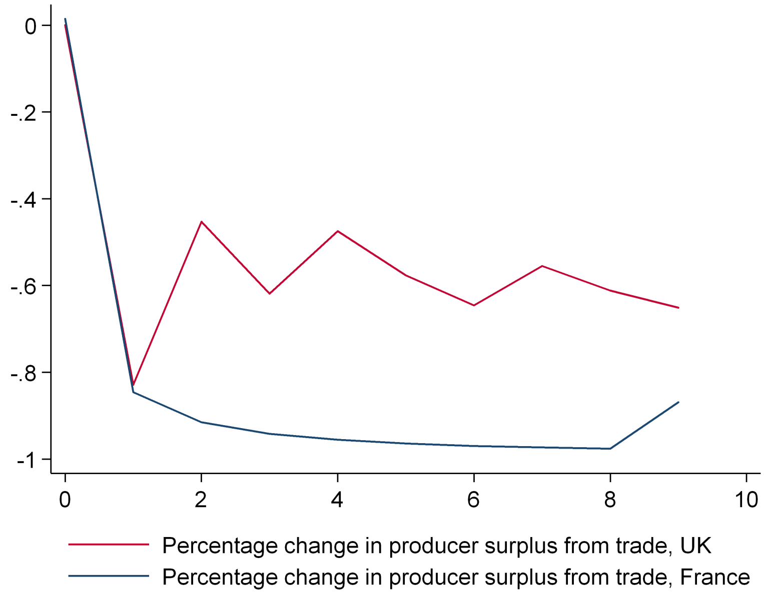


Figure A.21 - UK and France producer surplus gains from trade as the number of peak periods in France and the UK increases



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