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Electrical interconnectors: Market opportunities, regulatory issues, technology considerations and implications for the GB energy sector

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ABSTRACT

The linking of different jurisdictions or markets via electrical interconnection is a long established means of offering enhanced security of supply to the wider electrical system. In recent years, new incentives around exploiting market price differentials and facilitating the growth of renewable energy have represented the primary motivation for new interconnector projects. This paper provides a comprehensive overview of the technical options for delivering interconnectors, examines historical trends and discusses the ownership models, regulatory frameworks and market structures within which the investment case for new interconnectors must be made. Drawing on both technical and market considerations, the paper sets out the potential impact that interconnectors can have on the energy market and interested actors within connected markets before discussing in more detail the policy implications of the proposed roll out of new interconnector projects to the GB energy sector and suggests a number of factors beyond the current focus on consumer welfare could be given more prominence in the policy making around interconnector investment. The ways in which the UK's withdrawal from the European Union might impact on future and existing interconnectors in Britain is also discussed.

1. Introduction

An interconnector is defined variously as "a cable or overhead line connecting two separate markets or pricing areas" [1] or for example in the EU context as "a transmission line which crosses or spans a border between member states and which connects the national transmission systems of the member states" [2]. When connecting different markets or countries (though not necessarily when connecting different pricing areas within a single market), it is clear that a key feature of an interconnector is that it necessitates an agreement between at least two parties and cannot generally be carried out within the remit of a single transmission system operator (TSO).

Interconnector projects are long established. There are many examples of HVAC transmission lines facilitating the creation of single, synchronous grids spanning national boundaries. Interconnector development had historically been motivated by security of supply issues and the desire to share capacity and reserve but more recently has been motivated by opportunities to facilitate cross-border trading between markets with a clear price differential and so an economic incentive to trade energy. Interconnection is also seen as a means of providing the necessary market access to enable the expansion and full utilisation of intermittent renewable generation [3].

Further cited benefits of interconnection include their potential to provide ancillary services, for example in frequency response and reactive power markets [4]. They can also promote competition across a wider geographical area and, as a consequence, help to drive down consumer costs. Given the stated advantages as well as the advent of ultra-high voltage alternating current (UHVAC) and high voltage direct current (HVDC) technologies capable of power transmission over long distances, global interconnection is a topic of increasing interest [5].

This paper presents a systematic review of the technological and regulatory status of the interconnector industry and offers new insights for policy makers into both the opportunities they might facilitate and their potential impacts on other energy market actors and on overall policy objectives. To achieve this, section 2 sets out the main drivers for interconnection before a thorough overview of the present state of the industry is outlined in sections 3-5. This covers three main sections: a review of the technology options for interconnectors and their key attributes in relation to provision of power transfer and ancillary services (section 3); a discussion of the available ownership and governance models which facilitate interconnector development (section 4); and a quantitative review and analysis of existing HVDC interconnector

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projects (section 5) which offers an understanding of past and recent development trends.

The understanding gained above then feeds into an analysis and discussion of the potential impact of an interconnector on a range of interested energy market participants. First, section 6 takes the perspective of potential private investors and examines the various revenue opportunities that interconnectors can be used to exploit. Next, a systematic, qualitative review of the potential impact of increased interconnector roll-out on the full range of other energy market stakeholders is presented in section 7. Lastly, section 8 presents the key policy considerations related to increased interconnector deployment including a discussion of the potential impact of the UK's decision to withdraw from the European Union.

2. Background: drivers for interconnection

2.1. Security of supply and utilisation of resources

High voltage transmission network developments were initially motivated by the interconnection of different areas to facilitate the sharing of capacity and reserve between areas [6]. This was subsequently extended to interconnections between national grid systems [7]. This echoes the drivers behind the expansion of large interconnected grids in general, namely to increase security of supply, or to satisfy a given level of security of supply at least cost, by providing shared access to a diverse generation fleet thus enabling a pooling of generation reserves and increased use of the most efficient and cost effective plant.

Perhaps the most prominent multi-jurisdictional example of interconnected grid expansion is the development of the synchronous grid of continental Europe. This was developed via the formation of the Union for the Cooperation of Production and Transmission of Electricity (UCPTE) in 1951, originally an eight country cooperative of transmission system owners and producers on mainland Europe and an early forerunner of the European Network of Transmission System Operators for Electricity (ENTSO-E).

The original objective of the UCPTE was to enable optimum operation of power plants, which at the time often meant providing a means of utilising surplus hydro power within certain regions of the cooperative whilst saving on coal consumption in others [8]. It achieved this via the gradual build-up of firstly bi-lateral HVAC interconnector projects before ring and mesh connections between the countries were formed.

In recent years, as the penetration of renewable energy sources has continued to increase within national energy portfolios new motivations and economic drivers for increased interconnection become increasingly apparent. The intermittent and uncontrollable nature of these resources means it can be difficult for system operators to match local generation and demand in real time, as indicated by often highly volatile price differences between regions. Interconnection provides a means of reducing this burden by providing access to wider and more geographically diverse demand and storage markets in times of high output and, similarly, to new generation sources in times of low output [9].

Originally, interconnectors were developed by partnerships between state-owned or regulated utilities with the agreed aim to lower mutual costs but more recently some regulators such as those in GB, Australia and the US have encouraged interconnector development on a merchant basis where independent developers are granted license by the national utility to take advantage of price differentials between markets based on tests of projected project benefits.

2.2. Market integration

The basic economic case for interconnection between two electricity markets arises if there is a price differential between them. In theory, the interconnector owner is able to generate revenue in proportion to the value of the import volume times import price minus the export volume times the export price. In addition to the benefits accruing directly to the interconnector owner, if the interconnector is sufficiently large it will also act to influence the markets that it connects by narrowing the price difference between them where prices in the lower cost export market increase and prices in the higher cost import market reduce [1].

As illustrated in Figs. 1 and 2, the presence of interconnection between two markets alters the market conditions for a given snapshot in time and leads to a net gain in total global social welfare (yellow shaded areas) as well as a redistribution of welfare between producers and consumers within each market creating winners and losers. In reality, markets do not comply with a static price model but rather fluctuate over time depending on the level of demand and the availability of generation. This means that, depending on the nature of the two connected markets, it is possible that the economic incentives and with it the import-export flows may reverse depending on time of day, month or year.

To maximise the social welfare benefits of interconnection projects there is a general realisation that markets should be increasingly integrated, especially given the advent of intermittent renewable generation that relies on geographical balancing for efficient operation [9]. Relatively few studies have attempted to estimate the financial benefits for large regions of moving towards integrated electricity markets but those which have, tend to identify large potential gains. For example [10], estimated potential total gains of a fully integrated and efficient nodal pricing structure in the PJM US market to be \$2.2bn/yr whereas [3] presented estimated benefits of coupling markets via interconnectors across Europe to be €1bn/yr for day-ahead markets and €1.3bn/yr for intra-day and balancing markets. However, realisation of such benefits depends on the price signals coming from nodal pricing or market coupling being correctly interpreted and acted on by energy market participants on both the generation and demand sides and by parties that can invest in additional network capacity.

Given the scale of such potential gains there are programmes afoot across the globe to increase market integration and increase the efficiency of utilisation of interconnectors. These broadly fall into two categories of either consolidation or coordination. Consolidation is the merging of system operations into a single control area and has been pursued for example in the USA with the expansion of both the PJM and MISO control areas which have over a number of years merged with a number of smaller system operators to have control of operations over very large areas which allows for efficient use of the existing assets. A similar consolidation occurred in Australia with the National Energy Market superseding a number of distinct state organisations. In both cases regional market price divergence reduced significantly [9].

In some places there are significant barriers to the consolidation approach especially across international borders where national governments retain responsibility for security of supply. This means interregional coordination, via the optimisation or harmonisation of cross-border flows, is the means by which energy markets can be integrated.

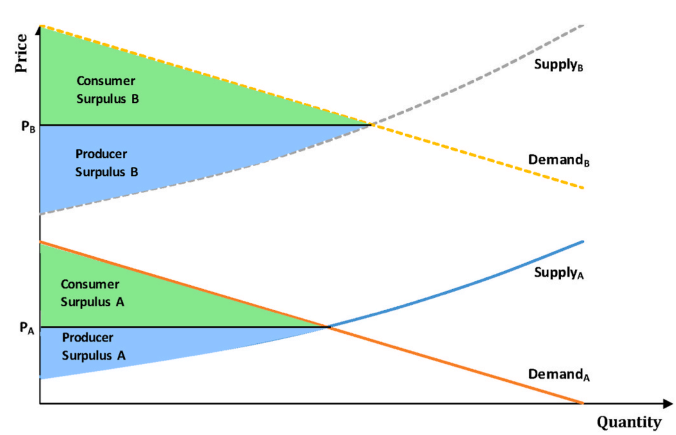

Fig. 1. Two markets without interconnection.

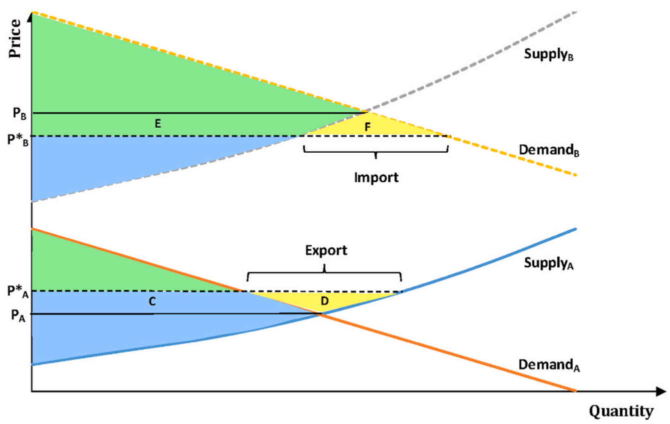

Fig. 2. Two markets with interconnection.

The clearest example of this approach is that of the move to integrate the electricity markets within the EU via market coupling.

Market coupling in the EU is currently undertaken at the day ahead market level and involves coordination between TSOs and power exchanges to provide information on available transfer capacity and offer and demand curves. These are fed into an implicit auction process whereby a market coupling algorithm utilises the available interconnector capacity and a series of zonal prices are determined dependent on the level of congestion across interconnectors. Day ahead market coupling has led to greater regional electricity price convergence indicating more efficient use of interconnection [9,11].

With high penetrations of solar and wind, day-ahead market coupling does not suffice for reaping the benefits of market coupling with inefficiencies apparent closer to real-time. Market coupling at the intra-day and balancing market level is more complex given the different platforms and products available in each country at this timescale. Due to this, integration has tended to be limited to a number of examples of bi-lateral or regional co-ordination such as the BALIT arrangement for trading replacement reserve between GB and France. The latter represents an example of a more recent trend of interconnectors contributing to ancillary services. Other examples include initiatives such as the Trans-European Replacement Reserve Exchange (TERRE) and Manually Activated Reserves Initiative (MARI) [12].

As will be discussed in sections 3 and 5, most recent interconnector developments use high voltage direct current (HVDC) technology. As the proportion of power infeed from non-synchronous sources increases, the potential for interconnectors to contribute to ancillary services becomes increasingly important and represents a possible additional source of revenue [13]. Such services are increasingly important in a decarbonised power system due to (a) the low short-run cost of low carbon generation and (b) the high variability and low inertia of systems with significant penetration of wind and solar power [14,15]. In addition, particularly in regions that predominantly import power via interconnectors, it is likely that this power is being utilised at the expense of existing generation capacity that would have otherwise provided a portion of the system ancillary services, thus further exacerbating the requirement.

3. Interconnector technology options and data

3.1. Comparison of HVAC and HVDC

High voltage alternating current (HVAC) technology has proven its effectiveness in generation, distribution and transmission of electrical energy for many decades. Its benefits include familiarity for transmission system owners and operators. It also avoids the need for active control to facilitate the sharing of frequency response and reserve between markets and allows the creation of large, higher system inertia, synchronous areas which reduces concern around system frequency stability. Further, it allows the interconnection to contribute to fault levels[1], aid system stability and contribute to reliable operation of protection [16,17]. However, HVAC technology has some limitations and challenges in the context of cross border interconnection which means that high voltage direct current (HVDC) technology is often considered as an alternative means of providing interconnection between markets. Where the interconnection requires an undersea or underground cable, it is usually the only practical option [18]. As highlighted in Fig. 3, HVDC projects are characterised by high capital expenditure which relates to the need for expensive converter stations using power electronics. These converter stations also incur losses but HVDC technology benefits from low transmission link losses. This contrasts with HVAC projects which don't require the conversion stage and so have lower up front infrastructure costs but instead suffer from higher transmission link losses and potential problems with reactive power requiring additional compensation equipment. When combined with the cable or overhead line (OHL) costs, this means that total costs rise more sharply with distance in HVAC systems than in HVDC systems. In addition, in contrast with HVDC, HVAC has limited ability to control the share of power flow between multiple lines operating in parallel with each other meaning that it may be impossible to fully utilise the total interconnection capacity. Where HVAC interconnection is relatively weak electrically, there can be a risk of unstable inter-area oscillations that can lead to areas being disconnected.

The eventual technology choice for a given project will be based on a combination of an economic assessment and a consideration of the desired technical performance requirements. The exact breakeven distance in respect of the cost of the interconnection itself will be influenced by several factors and will vary from project to project according to the main objectives and priorities of the link. For example, in OHL systems, the typical breakeven distance is variously reported to be

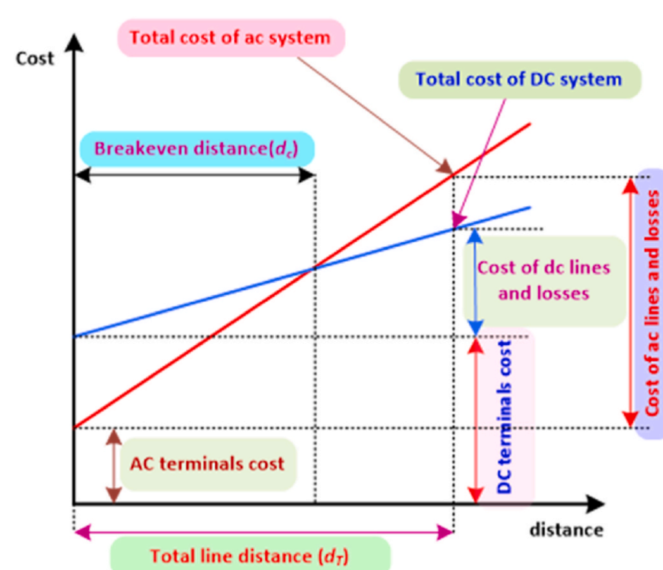

Fig. 3. HVAC and HVDC transmission cost versus distance.

[1] Fault level is a measure of the current that would flow were a short circuit fault to occur on the network. A high fault level helps with the identification of faults by protection equipment and with the support of voltages which, in turn, helps with system stability. However, fault levels must also not exceed circuit breakers' ability to safely interrupt fault currents.

anywhere in the region of 300–800 km, [19–23]. In some cases, e.g. for undersea connections or where it seems impossible to gain public acceptance of overhead lines, underground or submarine cables must be used. For such projects the distance beyond which HVDC is lowest cost is more typically in the range of 50–100 km due to the significantly increased AC losses caused by charging currents in cables although this distance may vary widely with voltage, power rating and the type of technology deployed within each technology bracket [20,24].

HVDC technology connected to a conventional AC power system involves the need for converter stations to convert power from AC to DC (exporting) and DC to AC (importing) at each endpoint of a link. Active and reactive power dispatch can be controlled to manage power flows up to the full capacity of the link and to help regulate frequency and voltage. HVDC allows for the connection of asynchronous AC systems (either with different frequencies or with the same unsynchronized frequency) and acts to decouple any connected AC networks in terms of fault propagation which can improve stability [25–27].

The two main categories of HVDC transmission technology, differentiated by the choice of circuit and device used in the converter valves, are line-commutated current source converters (LCC) and self-commutated voltage source converters (VSC). These have different characteristics in terms of voltage and power rating, physical size, converter station power losses, the way to control power flow and thus the ability to contribute to control of the AC power system to which a converter is connected and speed of reversal of power flow direction [28]. For projects using cables, the latter factor also influences the choice of the specific cable technology which in turn influences the maximum power rating of a given development. The current maximum capabilities of HVDC technologies are given in Table 1.

3.2. Potential ancillary service contributions

Increased penetration of low carbon generation sources like wind and solar power with low short run costs and high variability is placing increasing requirements and importance on balancing and reserve services [14,15].

Based on the technical attributes of the HVDC technology options for providing interconnector links, it is possible to compare the interactions and impacts of each on the AC systems to which they connect. Table 2 discusses the potential ancillary service contributions of LCC and VSC based HVDC and compares these to what would be provided by an HVAC interconnection, showing that the chosen technology can have a significant bearing on the ability of an interconnector to participate in ancillary service markets.

Both LCC and VSC technologies can be used to provide frequency response and reserve services although it should be noted that the scale of the contribution to these services is dependent on the generation at the remote end and the willingness to, for example, leave headroom on the link under normal conditions to allow for increased throughput in response to system events. Similarly, both HVDC technologies can contribute to system stability and damping if they have converter controls appropriately configured. However, the technical advantages of the VSC technology are highlighted in its ability to provide reactive power and voltage control as well as black start services to the grid. LCC in comparison has only discrete and limited reactive power and voltage control capabilities via switching of associated compensation devices and converter control, the use of which is restricted to times of low power throughput on the interconnector. VSC links can also potentially provide a small contribution to the fault level of the connected grid which is not the case for LCC technology. In contrast, a conventional HVAC link would provide a contribution to fault level via the generation connected at the remote end. Similarly, for all the other ancillary services discussed, HVAC would have an indirect ability to contribute depending on the remote end generation but none of these services would be deemed directly controllable, as they can be if provided via the appropriate HVDC technology.

Table 1
Maximum capability of HVDC converters under construction [29,30].

	LCC	VSC (MMC)
Rated continuous power transfer capability (per converter)	12000 MW	1400 MW
Rated DC voltage	±1100 kV	±525 kV
Type	OHL	underground cable

Table 2
Summary of potential ancillary service contributions of different interconnector technologies.

Service	HVAC	LCC-HVDC	VSC-HVDC
Frequency response and reserve	Indirectly through access to generation at the remote end	Directly controlled but depends on generation at the remote end	Directly controlled but depends on generation at the remote end
Reactive power and voltage control	Indirectly through access to nearby generation at the remote end	No, except at low transfer through associated filter banks and converter control	Yes
Black start	Indirectly through access to nearby generation at the remote end	No	Directly controlled but depends on generation at the remote end
Contribution to fault level	Yes, amount depends on generation at the remote end	No	Minimal, and only when converter and control system suitably configured
Contribution to system stability and damping	Indirectly through access to nearby generation at the remote end	Yes, if controls on the converter are suitably configured	Yes, if controls on the converter are suitably configured

4. Ownership and governance models

4.1. Regulated model

Regulated ownership is historically the most common model that has been used for interconnector development. In most jurisdictions, including in mainland Europe and the USA to date, regulated models are the dominant approach with interconnection often considered as part of the regulated asset base for the TSOs. Therefore, developments are typically treated as public projects. Given that interconnectors connect two market areas and these typically each have their own TSOs responsible for network ownership and system operation, more than one entity usually has to be involved in the development of a new interconnector. In such a case the TSOs would undertake and finance the project on a proportional basis and derive a regulated return on investment underwritten by their respective transmission customers in the same way as they do for normal transmission expansion. The regulated model essentially puts an upper limit on the returns that are allowed to be made on the investment and in some cases puts further mandates on the use of that revenue. For example, in Europe legislation exists which states that the interconnector revenues be used for certain purposes such as further transmission investment [31]. These rules are further extended and changed as part of the new clean energy package.

The main perceived advantage of the regulated model is that it provides a degree of transparency and revenue certainty which should in theory increase the incentive for interconnector development where beneficial and reduce the cost of capital required for it. Although in Europe the regulated model is the mandated approach (unless exemptions are applied for and granted) it might also be the only feasible way of delivering certain projects, for example those that can be identified as having social welfare benefits but that may lack a clear commercial incentive based on the expected ex post price differentials or transmission capacity payments [32,33]. Conversely, it can be argued that the regulator has ultimate power over returns which if not set at sufficient levels to incentivise development could lead to underinvestment in interconnection.

Cost allocation for a regulated interconnector project is an issue which requires careful thought as the expected benefits of a particular interconnector project may differ greatly between the different jurisdictions and stakeholders involved and may be difficult to determine in advance although methodologies are available in the literature [34]. It is generally accepted that a "beneficiary pays" principle is desirable to enable both direct and indirect stakeholder acceptance for a given project although in practice it may be difficult to achieve this. A strong cost allocation approach would look to use either upfront cost allocation or cost recovery mechanisms to avoid, for example, allocating costs to a region that does not benefit from an interconnection but incurs costs to enable the project [9]. There have been regulatory moves across the globe in recent years in Australia, the USA and Europe which look to strengthen cost allocation approaches for transmission expansion, including interconnectors [35–37].

4.2. Merchant model

Although work is ongoing to reduce the barriers to regulated interconnection it is still recognised that other means of incentivising development may be helpful or necessary in some circumstances [38]. In the merchant model a third party developer will propose and deliver the interconnector project. This entity will then be subject to the full risks and rewards associated with arbitrage opportunities reliant on difficult to predict and fluctuating market price differences. Where price differences exist the merchant model can be seen as an efficient model for encouraging interconnector development as market forces should always look to benefit from that opportunity. However, interconnection is known to inherently reduce price differences between the two connected markets which means there could be an incentive to undersize projects in order to ensure a revenue stream via congestion rent, without consideration of the wider social welfare implications. It is also argued in Ref. [39] that there are a range of issues that mean a wholly merchant model should not alone be relied upon to deliver sufficient transmission investment.

As each interconnector project will produce winners and losers (discussed further in section 7) it can be argued that the merchant model removes a contentious layer of decision making from the process as agreement between all relevant parties in the respective market areas being interconnected is not necessarily required and issues such as cost allocation between multiple parties are removed. For example, if studies suggest one market area might see net price rises due to an interconnector it may be difficult for its authorities to grant permission under the regulated model despite overall welfare gains [32].

In the USA the FERC 1000 order sought to encourage greater use of the merchant development model by reducing entry barriers to merchant developers, albeit there is little evidence to date of the market positively responding to this [36]. Australia has also experimented with merchant interconnector projects in the past through the Basslink and Murraylink projects, albeit with limited success [40]. As mentioned previously, in Europe it is possible, though still relatively uncommon, to apply for exemption from the regulated regime which then enables a merchant developer to charge and keep rents from the interconnector [41]. In GB, regulated transmission licensees are forbidden from treating Interconnector projects as part of the regulated asset base which meant, until recently, that the merchant model was the only mechanism that could be used to develop interconnection projects in Britain after application for exemption. Therefore each of BritNed, Moyle and East-West Interconnector projects were developed under a merchant model. This created an obvious tension with regulatory regimes in any of the countries to which a new GB interconnector might connect which favour interconnector development by regulated utilities. This can be seen as having somewhat motivated the new 'cap and floor' regime in Britain that is discussed in the next subsection.

4.3. Cap and floor model

A new hybrid regulatory scheme has been developed in Britain for application to the NEMO interconnector in 2013 and subsequent projects [42]. It was designed to combat an emerging view that further interconnector project investment with Europe was increasingly hard to incentivise under the merchant model. To tackle this a "cap and floor" regulatory model was developed by British Office of Gas and Electricity Markets, Ofgem, with the additional floor element designed to de-risk investment. The floor element of the model is determined via a regulated asset value (RAV) model and is based on a determination of capital expenditure, depreciated over the project lifetime and an ex-ante assessment of operational costs over the project lifetime. From this a minimum allowed return can be set which allows an efficient developer to recover their costs and ensure they are financeable but should not in itself act as a guaranteed source of value creation for the investment [42]. In other words, for a positive investment decision to be made under the scheme the forecast revenues should be higher than simply those available via the guaranteed floor price.

Value is created in the same way as with the traditional models whereby market based congestion or capacity revenues can be generated, up to the level of the cap. The principle used is that the level of the cap should be proportional to the level of risk that the developer is exposed to which means the appropriate levels of the cap and floor are inter-related. A higher floor on returns means lower risks for the developer which in turn should mean that consumers are entitled to capture more of the upside benefits via a lower cap to the revenues that the developer can keep. The cap is calculated using a capital asset pricing model (CAPM) which accounts for the long term risk free rate and the equity risk premium in each market [42].

5. Summary of existing HVDC interconnectors

As was noted in section 2, HVAC interconnections were the basis of almost all early interconnections between different jurisdictions. However, they have been much less common in recent years due to many interconnections requiring underground or submarine cables for which AC technology is not well-suited. This, coupled with its additional controllability means that HVDC has therefore been the dominant technology for interconnector development in recent years. This section provides a summary of HVDC interconnector developments identified from published sources to have been undertaken in the past five decades.

Around 100 projects are identified from publicly available data in Refs. [30,43–47]. The projects include those that are clearly interconnector projects, in that they span two jurisdictions or connect two isolated regions within a single country but also a number of selected HVDC projects within a single country which are deemed to have, at least partially, a purpose of interconnecting grid systems or crossing market areas. It should be noted that the identified projects do not represent an exhaustive list of globally operational HVDC links, with links that are primarily for the purpose of connecting remote generation, as opposed to providing two-way interconnection, typically omitted.

Fig. 4 shows a graphical representation of the identified projects in terms of the evolution of total project capacity and transmission distance by year of deployment.

The data is split into LCC and VSC and further differentiated based on whether the projects are known to be cable based, OHL based, a mix of cable and OHL or back-to-back (conversion from AC to DC and from DC back to AC with no significant distance of cable or OHL in between).

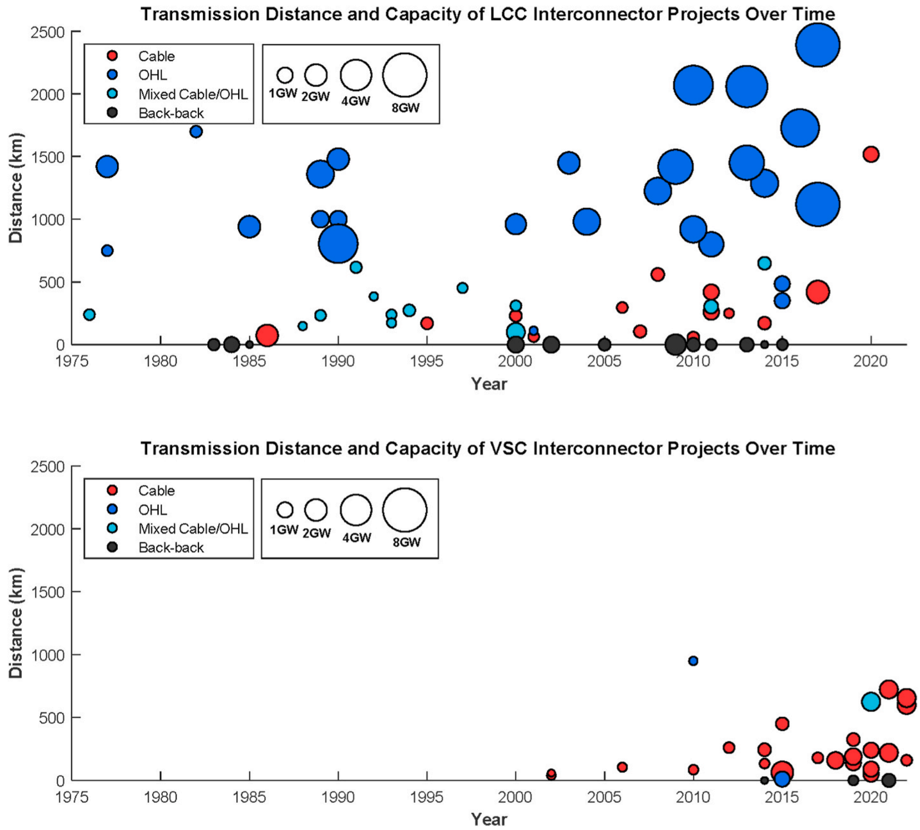

Fig. 4. Time evolution of distance and capacity of HVDC interconnectors.

There is a clear trend of an increase in recent years of the capacity of OHL based LCC projects with a number of multi-GW projects being installed but even some early examples of LCC projects were relatively large scale with capacities of 2 GW.

The newest large scale LCC projects are dominated by long distance bulk power transfer installations in large countries like China, India and Brazil with installations in excess of 2000 km now common, one example being the 2400 km, 8 GW Jiuquan-Hunan link in China. This expansion in capacity and distance is facilitated by a concurrent increase in the maximum voltage level available for use in interconnector projects, which for OHL ratings are now upwards of 800 kV. This compares with cable or mixed cable/OHL LCC based projects which are limited in capacity by the cables themselves and have expanded from typically a few hundred MWs in size to 1–2 GW more recently. Due to the high capital and installation cost of the cables and lower available voltage levels, transmission distances in cable-based projects have tended to be no more than a few hundred km although several proposed projects for the North Sea are now looking at transmission distances in the range of 600–800 km including links from Norway to Great Britain and Germany respectively. Back-to-back LCC projects also tend to be relatively low capacity ranging from 150 MW to 1.8 GW.

With regards to VSC based interconnector projects, it can be seen that they are a much newer technology although their prominence is becoming increasingly clear. The vast majority of projects are cable based and there are only two examples using OHL, three that are back-to-back and just one known mixed cable and OHL. Up until 2015 all VSC based projects had been less than 1 GW but since then and over the course of the next few years a number of installations in excess of this have been or will be built, the largest being the INELFE project at 2 GW (2×1 GW) [48]. Similarly, the transmission distances associated with VSC based cable projects tends to be limited to a few hundreds of kilometres.

6. Market structures and potential revenue streams

6.1. Market view of AC and DC interconnection

From a market perspective interconnection over an HVDC link is a more straightforward prospect as the flows are fully controllable and a given transfer can be treated as equivalent to pre-scheduled load in the exporting system and must-run generation in the importing system. This means that the interconnector can be fully utilised and, in general, the market settlement for interconnection flow can be matched to the physical delivery except in the case that the system operator needs to manage a system constraint. This compares to an HVAC interconnection which, even with phase-shifting transformers or thyristor controlled series compensation, has limited controllability and could be vulnerable to sudden changes in flow pattern due to other system faults or outages [49]. For this reason, AC interconnectors typically have to be dispatched below capacity such that they include a reliability margin that accounts for any system constraints and assures continued safe operation in the event of contingencies.

6.2. Capacity allocation methods

To determine which stakeholders gain access to use of a given interconnector, two main market based methods for capacity allocation are commonly used. These are explicit and implicit auctions respectively.

6.2.1. Explicit auction

Explicit auctions have been commonly used in the case of HVDC interconnectors between two separated markets, for example on connections from GB to Ireland or France. In this method, the TSOs determine, ex ante, the capacity available for auction and users bid for the physical right to use the capacity [50]. The bids are sorted, highest first until the capacity is completely utilised and a marginal price is determined. If a uniform clearing price mechanism is used, then all successful bids will pay the marginal price. Alternatively, if a pay as bid rule is in place then successful entrants are charged at their bid value. The size of the rights obtained can be limited to preserve competition, may be in either direction and may be interruptible [1]. It is typical for products covering different time periods, e.g. a year, a month or a day, to be sold at varying intervals. If capacity might be unused a use it or lose it rule is often employed which releases the capacity back to the market for all players. Owners of longer term rights are typically able to transfer these on in subsequent auction rounds.

6.2.2. Implicit auction

Implicit auctions require a common market mechanism between the TSOs whereby energy offers and bids are submitted in each organized market area. These are all included in a centralised dispatch which matches demand and supply optimally, or some other area price discovery mechanism. If there is sufficient interconnector capacity, then the two market areas' prices equalize (subject to how network losses are treated) but if congestion occurs (i.e. when the optimal dispatch would utilise more than the available interconnector capacity) then a price difference is visible at the two ends of the interconnector and the interconnector is fully dispatched [50]. In this market set-up the revenue returned to the owners of the interconnector rights is known as the congestion rent and is equal to the price difference between the two markets multiplied by the volume of interconnector flow. This means that implicit auctions for interconnection dispatch could be used in the day ahead market (alongside the unit commitment problem) in conjunction with an explicit auction regime that administered the capacity rights [1]. In cases where neighbouring markets with interconnection are co-ordinated and integrated via implicit auctions (as with the day ahead market in Europe) this is known as "market coupling".

6.3. Investment case and revenue opportunities

As has already been noted, the main financial value of interconnectors is their ability to exploit arbitrage opportunities over various market timescales. Although the classical representation suggests interconnectors are desirable when a straight price difference exists between two markets or countries, in reality it is often the case that price differences fluctuate over time. Therefore, arbitrage opportunities typically come in three forms as described in Ref. [51] and discussed below. In addition to traditional arbitrage opportunities, increasing focus is also moving to how interconnectors can participate in ancillary service markets.

6.3.1. Price level value

This relates to a long term sustained difference in average baseload wholesale price level due to differences in generation mix, fuel and carbon prices, or system charges. An example of an interconnection that has historically benefited from a sustained price difference between the markets is that of the IFA interconnector between Britain and France. The French system is dominated by nuclear power which generally has a low marginal cost of generation compared with the historically fossil fuel dominated British market. It is shown in Ref. [52] that across 2015 the weekly average wholesale electricity prices, taken from the Platt's European Power Index, in the UK were higher than in France and Fig. 5 shows the 5 min averaged interconnector flows on the link for the whole of that year.

It can be seen that the price level difference between the two markets leads to export of the full transmission capacity from France to Britain being the dominant usage of the interconnector with flow direction reversing in only a relatively small number of short time periods.

6.3.2. Price shape value

This relates to differences in wholesale prices due to a discrepancy in

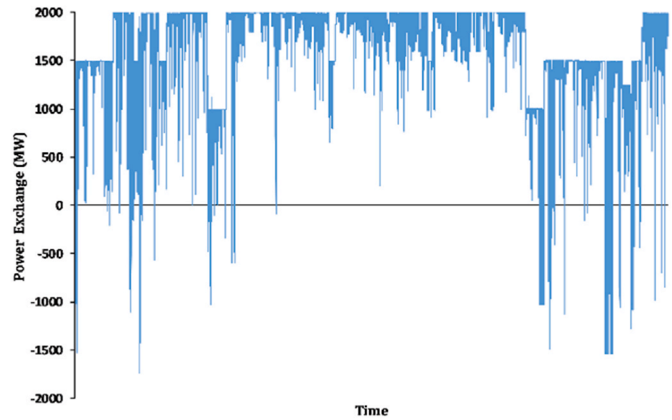

Fig. 5. Five minute average IFA interconnector flows from France to GB in 2015. Data from [53].

the timing of generation or demand patterns between the connected regions. Differences in demand profiles may be apparent, for example, when an interconnector crosses different time zones leading to an offset in the timing of demand pick up and turn down occurrences. Similarly, in circumstances where the interconnection spans areas with significantly different generation characteristics it is likely that price shape differences will be present which could lead to flows switching directions in different time periods with benefits accruing to consumers in both areas as a result. An obvious example of this are the connections between Norway and Denmark. Norway has a generation mix that is dominated by flexible reservoir storage hydro power leading to relatively stable electricity prices. In contrast, Denmark has a very high penetration of intermittent renewable generation in the form of wind energy which is known to not only lower average wholesale transmission prices but to introduce increased levels of variability [54,55]. At times of high wind output in Denmark there is likely to be an excess of generation and prices will fall leading to export of power to Norway which may take the opportunity to conserve water serving its hydro stations. Conversely, when wind output is low, prices are likely to rise in Denmark and Norway could take the opportunity to utilise some of its water resource and export its hydro power into the more expensive market. Fig. 6 shows physical exchanges of power on the Skagerrak 1–4 transmission links between Denmark and Norway for 2016 and highlights how the price shape volatility described above leads to highly changeable flow directions across the interconnectors.

6.3.3. Price volatility value

This relates to unpredictable price peaks or troughs arising from, for

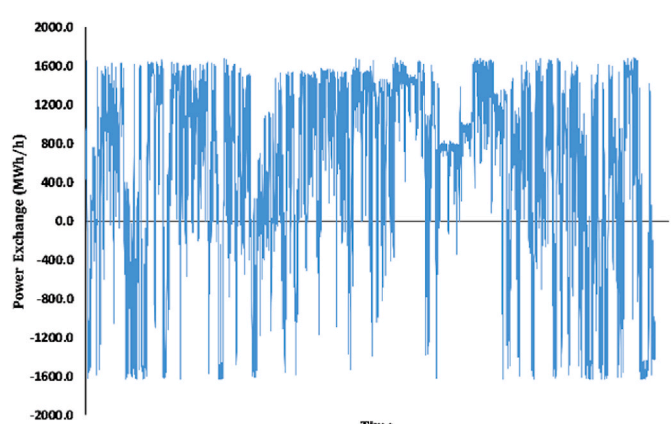

Fig. 6. Hourly physical exchange on Norway to DK-West interconnections in 2016. Data from [56].

example, outages, demand spikes or weather phenomena. The loss of large thermal generation units or a substantial portion of wind output due to extremely high winds will cause a sudden shift in dispatch which may temporarily alter power prices and change the required or desirable interconnector flows. This type of arbitrage opportunity might not represent a significant contributor to the overall economics of any particular interconnector link but such phenomena may account for some of the short term variability that is evident within Figs. 5 and 6 above.

6.3.4. Ancillary services

As was discussed in section 3.2, there are numerous opportunities for HVDC interconnectors to participate in ancillary service markets. As is outlined in Ref. [4], this is attracting interest from SOs and includes utilising their ability to quickly ramp power in either direction across the full import export range, subject to operating conditions at each end, to provide either fast frequency response or facilitate shared reserve between SOs.

To participate in the frequency response and reserve markets in particular an interconnector may have to inhibit the full use of interconnector capacity for traditional energy trading and there is an obvious economic trade-off to doing this [57]. Interconnectors to date have traditionally not entered the ancillary services market but there are some recent examples which give an indication that the financial rewards for providing ancillary services may well be attractive. On the 700 MW Skagerrak 4 link between Denmark and Norway 100 MW of the capacity was allocated for the provision of reserves for a period of 5 years with the remaining capacity kept for day-ahead trade. Despite accounting for only 14% of capacity, experience suggests that 33% of total revenues on the link came from reserve trading [9]. Finding an optimal allocation between day-ahead, intra-day and reserve trade is likely to be a challenging task that depends on fluctuating market conditions.

Looking to a near future with growing levels of interconnection it seems probable that average price differences between interconnected markets will converge and eat into traditional revenue streams. Couple this with a growing need for new ancillary service providers as traditional thermal plant are displaced from the system and it seems clear that ancillary service provision could become an increasingly important revenue stream for interconnector projects.

7. Stakeholder impact assessment

Given that the scale of expansion in interconnector projects in the coming years could be unprecedented for many regions it is possible that stakeholder knowledge of relevant implications could be low. Tables 3 and 4 have thus been designed to act as an introductory reference tool for decision makers and interested parties within each stakeholder category as to how interconnectors may impact their field. They present a qualitative assessment of the expected impact of interconnectors on the full range of electricity system stakeholders and have been collated into a single source with reference to the authors own experiences, discussions with industry experts and knowledge of the diverse existing literature in the area.

Table 3 outlines a number of high level system, market and policy impacts that interconnector build out might be expected to generate. Table 4 then summarises which of these potential impacts apply to the full range of relevant stakeholders and discusses how these may manifest in the extreme examples of predominantly importing and predominantly exporting regions. It should be noted that bi-directional flows are common in interconnector projects and it is possible that regions will see both import and export impacts at different times. As such, it should be remembered that these tables discuss indicative impacts that will also be influenced by many other variables within an ever changing and complex system. The scale and types of impact from any one interconnector project is dependent on its size relative to the markets it connects, the level of existing interconnection between the markets and the nature of the subsequent power flows.

Table 3
Summary of potential interconnector impacts.

Interconnector Impacts	Discussion
Electricity market price	Interconnectors can cause electricity market prices either to fall (if importing and facilitating the use of cheaper generation from another market) or rise (if exporting and facilitating increasingly expensive generation to run within your own market)
Generation mix	Interconnectors can impact on the generation mix within a country by displacing the need for domestic generators or facilitating their growth. This can have knock on implications for security of supply, physical network flows, network investment and government policy that may favour certain types of generation or prefer security of supply to be ensured from domestic sources.
Security of supply	Historically, interconnectors were often seen as increasing security of supply (or providing it at lower cost) by allowing access to a wider generation fleet. This remains the case in, for example, the GB capacity market [58]. They may also displace the build out of domestic providers of reserve or reduce domestic generators' income from ancillary services leading either to closure of existing plant or failure to build new generation capacity. In the event of reduced numbers of generators providing ancillary services, the ability of interconnectors to act as replacements will be a key concern and will depend on the technology used. However, the extent to which government policy and markets are content to rely on imports from other jurisdictions via interconnectors to contribute to security of supply is generally uncertain.
Network flows	Interconnectors will act as a large sink or source within an electricity system and will inherently alter the physical flows with potential knock on implications for constraint management and network investment within the domestic system.
Network investment	Interconnectors may require accompanying additional upgrades within the existing transmission systems to accommodate changes in physical system flows. If interconnectors lead to reduced or increased levels of domestic generation this may also affect the wider network investment decision making process.
Government Policy	Interconnectors can help governments achieve specific policy objectives, for example facilitating the growth of renewables by increasing the ability of the whole system to distribute and absorb these intermittent resources or by lowering the cost of electricity in an importing jurisdiction. Governments are ultimately tasked with providing a framework for producers to work in a viable industry that supplies a secure electricity supply at lowest cost to consumers and as such they will have an interest in the dynamics of all system and market impacts from interconnectors. Thus, although a first priority is generally that prices to consumers are low, falling revenues to domestic producers would also be a concern if it leads to generation closures or a decline in investment.

8. Policy implications

The preceding section raised a number of issues for energy policy makers. This section presents a discussion of policy implications through the lens of the island system of Great Britain. This is served at the time of writing in 2019 by 5 GW of interconnector capacity via two links to Ireland (1 GW total) and three more to continental Europe (2 GW to France, 1 GW to Netherlands and Belgium). Further 1 GW and 1.4 GW links to France and Norway respectively are under construction. This relatively low total measures against an observed transmission system peak demand in 2018 of 50.7 GW and installed capacity from other generation sources of 99.5 GW [59,60] which gives a present ratio of interconnector capacity to installed capacity of around 5% compared with the EU's policy objective of a minimum of 15% by 2030 [61]. GB

Table 4
Summary of indicative stakeholder impacts referenced to importing and exporting market area examples.

Stakeholder	Impact Type	Discussion of Potential Consequences	
		Predominantly Importing Area	Predominantly Exporting Area
Government	Policy Objectives, Generation mix, Electricity Market Price, Security of Supply, Network Investment	Potential to contribute to security of supply although may also displace indigenous providers. May help meet local decarbonisation targets by reducing dependency on domestic fossil fuel generation although no guarantee that global emissions will fall. Scope for expansion of local renewables although may now also be exposed to competition with renewables in the remote market. Domestic electricity prices likely to fall but may give rise to policy challenges to help domestic generation fleet.	Potential to help meet renewable energy targets by providing additional customer base but could facilitate increased use of domestic carbon intensive generation as well. Local electricity prices likely to rise.
Consumer	Electricity market price	Likely to see prices fall	Likely to see prices increase
Retailer	Electricity market price	Likely to see local prices fall; the interconnector also permits direct trade with producers in the remote market.	Likely to see local prices increase.
Transmission System Operator (TSO)	Network Flows, Security of Supply, Generation Mix	New network flows may increase the need for constraint management. Increased access to reserve generation but potential for displacement of domestic generation and reduced offering of ancillary services. Could lead to lower system inertia and increased ancillary service requirements.	New network flows may increase the need for constraint management. Increased market opportunities for domestic generation.
Transmission Network Owner (TNO)	Network Flows, Network Investment, Generation Mix	Possible need for increased network investment to facilitate new network flows and any subsequent changes in generation mix.	Possible need for increased network investment to facilitate new network flows and any subsequent changes in generation mix.
Distribution Network Owner/System Operator (DNO/DSO)	Network Flows, Network Investment, Generation Mix	Potential for localised secondary effects on distribution systems if parallel to major transmission system level network flow changes. If interconnector facilitates increased renewable generation some of this may be distribution connected and impact local networks	Potential for localised secondary effects on distribution systems if parallel to major transmission system level network flow changes. If interconnector facilitates increased renewable generation some of this may be distribution connected and impact local networks
Baseload Generator	Electricity Market Price, Security of Supply	Reduced revenue potential through lower prices. Lower load factor through increased generator competition – higher impact likely to be on gas and coal over nuclear. Increased competition in any capacity market. Increased opportunity in balancing, reserve and other ancillary service markets but also exposed to increased competition in energy markets	Increased revenue potential through higher prices. Higher load factor through an increased demand base. Increased opportunity in any capacity market. Increased opportunity in balancing, reserve and other ancillary service markets.
Load Following Generator	Electricity Market Price, Security of Supply	Reduced revenue potential through lower prices. Lower load factor through increased generator competition – low efficiency plant impacted most. Increased competition in any capacity market. Increased opportunity in balancing, reserve and other ancillary service markets but also exposed to increased competition in energy markets.	Increased revenue potential through higher prices. Higher load factor through an increased demand base – low efficiency plant benefit most. Increased competition in any capacity market. Increased opportunity in balancing, reserve and other ancillary service markets
Peaking Plant	Electricity Market Price, Security of Supply	Reduced revenue potential through reduced price volatility and lower peak prices. Lower load factor through increased generator competition. Increased competition in any capacity market. Increased opportunity in balancing, reserve and other ancillary service markets but also exposed to increased competition in energy markets.	Potential for decreased revenue due to lower price volatility and lower peak prices. Higher load factor through an increased demand base. Increased opportunity in any capacity market. Increased opportunity in balancing, reserve and other ancillary service markets
Renewable/Solar Centralized Generator	Generation Mix, Security of Supply, Network Flows	Reduced revenue potential through lower prices. Even in market areas that are net energy importers, increased export potential at times of high renewables availability but reliant on the market interactions. Reduced load factor possible but unlikely as curtailment of interconnector import likely to be prioritised ahead of renewables. Changing network flows may impact localised congestion issues. Risk of curtailment if interconnector imports plus renewables output exceed system stability limits. If imports lead to closure of domestic thermal plant, increased opportunity for participation in balancing, reserve and ancillary service markets but competition from the interconnector itself	Increased revenue potential through higher prices. Increased export potential at high output leading to higher load factor. Changing network flows may impact localised congestion issues. Increased competition in balancing, reserve and ancillary service markets
Distributed Generation	Generation Mix, Security of Supply, Network Flows	Reduced revenue potential through lower prices. Changing network flows may impact localised congestion issues. Loss of thermal plant may increase need and opportunity for participation in ancillary service markets	Increased revenue potential through higher prices. Changing network flows may impact localised congestion issues.

has a diversifying existing generation mix which relies on traditional thermal generation in the form CCGT, nuclear and decreasingly coal as well as increasing amounts of wind and solar generation amongst others [60].

With increasing levels of renewable penetration, a number of thermal generation units coming to end of life and a slow market for new generation capacity, new interconnector projects have been strongly encouraged for GB with decision making on whether to grant new interconnector projects under the previously discussed cap and floor regime based predominantly on a calculation of GB consumer welfare [62]. This means that there is a substantial number of projects either in the development pipeline or under consideration. A total of nine new interconnector projects have been granted cap and floor status with a further two projects being granted exemption for a merchant connection meaning there is over 13 GW of new interconnection capacity that could potentially come online by the mid 2020's with several further projects also mooted [60].

It can reasonably be assumed that in the short to medium term GB would continue to act predominantly as a net importer of energy via interconnection as, even with the strong level of build out expected, interconnection will remain modest relative to the level of demand thus limiting the level of convergence in wholesale energy price with mainland Europe. This means in general terms the discussion points in Table 4 relating to importing areas are likely to be applicable to GB stakeholders with lower wholesale prices leading to consumer welfare benefits. However, the existing evidence base suggests there are a number of further issues related to the potential impacts of increased interconnection on the GB system which could merit a widening of the scope or a re-evaluation of the weight given to factors within the decision making process around interconnectors. These are explored in sections 8.1-8.3 while section 8.4 discusses the potential implications that the UK's withdrawal from the European Union – "Brexit" - could have on GB's interconnection potential.

8.1. Security of supply

One motivation for building interconnectors is to either increase security of supply, or satisfy a level of security of supply at lowest cost by expanding the available asset base to provide it. The evidence suggests that interconnectors have indeed provided significant benefit in this sense with a number of empirical examples from Europe showing that Norway depends on imports from Sweden during dry years, France imports up to 10% of peak demand during cold spells and that Belgium was able to import power to compensate for a temporary loss of a nuclear plant in 2013 [63].

However, there is a degree of disagreement as to whether interconnectors can always be relied upon to provide security of supply. It can be argued that expansion of interconnection capacity necessarily comes in place of other domestic solutions such as generation build out. In an assessment of the impacts of future construction of interconnectors from Britain analysis by Aurora Energy in Ref. [64] suggests that if 10 GW of interconnection is added to the GB system it would displace 7 GW of new gas capacity which would be built in the counterfactual.

Estimating the ability of traditional thermal generation to contribute to security of supply is relatively easy using analysis of the historical availability of generating plants to determine how likely it is that they are available to contribute to system security during a stress event. For interconnectors it is possible to perform a similar historical analysis of physical availability of the interconnector assets and determine a de-rating factor. However, it is argued in Ref. [64] that this provides little certainty if, for example, the stress event is caused by cold weather and low wind speeds as there is a high chance that this could also be affecting Western Europe increasing prices there and reducing the likelihood of exports being available from the sending end even if the interconnector itself is available.

A counter-argument might contend that historical examples of such phenomena could be accounted for in a de-rating analysis of interconnector power flows and point out that you also cannot guarantee the availability of domestic generation during individual stress events. To be confident of the availability of power transfer across an interconnector, the generation adequacy analysis performed for the market at one end of the interconnector ought really to be extended to the other market. In other words, generation adequacy would be assessed for the single interconnected system with the interconnector acting as a constraint on utilisation of the generation available in any one region. As is argued in Ref. [65], for completeness this kind of analysis should also take account of network constraints and the location of generation within a region, which is a feature of the capacity market on the island of Ireland [66].

Even if price differences are apparent during a stress event, the argument has been made that interconnector flows have not always historically acted rationally in response to price triggers meaning that they could potentially reduce security of supply if they displace domestic generation because they are less reliable. However, analysis in Ref. [67] suggests that market coupling is improving the response of GB interconnectors to price differences with France and the Netherlands, thus arguably increasing their reliability during stress events. This furthers the argument that a thorough and well-founded de-rating methodology accounting not just for availability of interconnector assets but also power flows can be used to ensure interconnectors can make a sound contribution to overall security of supply.

However, another argument is that the extent to which interconnection can be relied upon may change over time. If increasing amounts of interconnection act to equalize market prices to the extent that a historically importing market, like GB, is no longer a reliable importer of power then it may be necessary to reduce the de-rating factors of interconnectors significantly leading to a need to rapidly replace this capacity deficit. Another problem that has been identified in relation to security of supply and interconnectors is that their presence in itself poses a risk to system operation and requires close coordination between the interconnected systems. It is suggested in Ref. [9] that many major recent blackouts (Italy and New York in 2003, Western Europe in 2006 and India in 2012) can, in some part, be attributable to a lack of appropriate coordination among system operators that have a shared responsibility for managing interconnector flows. Such experiences mean that interconnection might be viewed as a threat to security of supply although improved practices and learning from such events may be expected to mitigate against encountering similar problems in the future. Moreover, where an interconnection is based on HVDC technology, the power electronic converters can act as a 'fire-break' preventing the cascade of a disturbance from one region into another [68].

8.2. Market price and existing generation assets

Analysis in Ref. [64] looks at the expected impact on domestic generation of a 10 GW rise in interconnection in the GB system and finds a significant drop in available revenues. For a study period of 2015–2040 with incremental build out of interconnector capacity it was estimated that revenue potential for domestic generators would reduce by 10% on a present value basis. The majority of the drop comes from the wholesale market due to lower prices and reduced utilisation. Based on their own interconnector build out assumptions the study estimated that an extra 4.4 GW of interconnection capacity by 2020 would lead to a 3% reduction in wholesale price whereas an extra 10.2 GW by 2030 would result in a 7% reduction. Although seemingly modest, the study found that the implications of the reduced prices coupled with lower utilisation hours could be potentially severe and fall disproportionately heavily on mid to low merit-order generation assets such as lower efficiency CCGT plants which, in Ref. [64], are expected to see a roughly 60% reduction in revenue potential in total over a 25-year period from 2015 to 2040 against the scenario where there is no new interconnection. This is compared with modelled total revenue reductions for high efficiency CCGT of around 30% and for peaking plant of around 20%.

Wind generators were found to be significantly less impacted with a 6% modelled revenue fall. The reduction in profitability, alongside a perceived uneven playing field in the sense that interconnectors in GB are exempt from certain network charges and carbon taxes as well as having access to specialist funding streams, is the main reason that interconnector build out is expected to coincide with a lack of investment in new CCGT.

As discussed previously, the GB regulator's decision making on GB interconnector projects considers only impacts in GB and tends to put a much higher weighting on consumer welfare than producer welfare impacts. This can be evidenced by the decision to grant cap and floor status to certain proposed interconnector projects even if internal analysis suggests the negative impacts on the producer welfare of existing generators and other interconnector projects would cumulatively outweigh the consumer benefits [62]. A total social welfare approach, aggregated over both interconnected markets, could be argued to be a more rounded approach to determining the overall viability of an interconnection project. Indeed it could be argued that very few interconnection projects would ever be supported if all governments and regulators focused only on the local consumer welfare implications of interconnection.

8.3. Carbon emissions

One of the main motivations behind increased interconnection in recent years, has been to facilitate increased build out and utilisation of renewable energy with an overarching ambition to reduce global carbon emissions. Where financial support to renewable generation makes its development and utilisation the cheapest option from a market perspective, the development of interconnection to provide access to cheap energy should enable utilisation of renewables to be maximised. However, at least two major studies of increased interconnection in Europe have shown that facilitating renewables does not necessarily lead to a reduction in total carbon emissions, especially in the near term. A study done as part of the Twenties project in 2011 as well as the report by Aurora Energy, discussed earlier, both found that developing increased levels of interconnection across the North Sea could potentially lead to an increase in total CO_2 emissions [64,69]. Although interconnections with the GB system allow a large reduction in total emissions from Britain and therefore help to meet domestic targets, they are actually found to facilitate a relatively greater increase in emissions in the rest of Europe. The reasoning behind this is that interconnectors are indiscriminate with respect to generation technology and simply facilitate the cheapest generation at any given time. This means that, as well as enhancing the output from low cost renewable generation, interconnectors could also allow cheap coal and lignite plants from across Europe to displace cleaner forms of thermal generation such as CCGT. This serves as a reminder that, in order to facilitate global emissions reductions, the build out of interconnector capacity should be accompanied by complementary policies to increase the cost of carbon or minimise production from heavily polluting generators by some other means.

8.4. Brexit impacts

The vote by the United Kingdom to leave the European Union, the subsequent triggering and then extension of the Article 50 process means that at the time of writing, bar the granting of any further extensions or political moves to reverse the decision, the UK will legally exit the EU in October 2019 [70]. The subsequent legal frameworks that form the new relationship between the UK and the EU, 1st during a transition period and then long–term will have a significant bearing on how the GB electricity market and its interactions with the rest of Europe, including via interconnectors, are impacted.

The most obvious and immediate impact of Brexit is to create a degree of uncertainty as to the future relationship between the GB and EU energy markets. The investment models, set by the GB regulator, for the current pipeline of GB interconnector projects are likely to remain the same after Brexit from the GB perspective and Ofgem remain supportive of interconnector development but the evidence suggests the national regulators of IEM members at the other end of interconnectors are likely to be more hesitant. For example, the French regulator, CRE, has suspended decision making on all interconnectors projects not already approved, stating that it is "not in a position to decide whether any new interconnector project between France and the United Kingdom is beneficial to the European community before the withdrawal conditions of the United Kingdom from the European Union are clarified" [71]. This means that at the very least the uncertainty caused by Brexit will lead to delays in the development timeline of interconnector projects, with French projects like FAB link and GridLink already affected, while any extreme divergences brought about by a disruptive Brexit scenario could reduce the number of interconnectors that are rolled out at all. Further evidence of the potential political implications of Brexit on interconnector roll-out for GB is the advancement of plans between France and Ireland to build the proposed Celtic interconnector project [72]. Given the investment implications it seems likely that advancing the Celtic interconnector project could have knock on implications that reduce the prospect of the proposed GreenLink interconnector between Ireland and GB.

At the time of writing GB is a full member of the EU's internal energy market (IEM) which means it has benefitted in recent years from the previously discussed move towards market coupling within the region. GB and European markets are currently coupled via implicit auctions at the day ahead level (since 2013) and explicit auctions at both forward and intraday market level. There are ongoing plans to move towards implicit market coupling at intraday level as well via the XBID (cross-border intraday) arrangement. For EU members market coupling is facilitated by compliance with the current market acquis and adoption of all advanced market rules with enforcement overseen by the European Court of Justice (ECJ) [73].

Whether or not GB is able to maintain its present status and continue to reap the benefits of market coupling depends on continued membership of the IEM. At present, the UK government seeks a future relationship with the EU which ends oversight of the ECJ on UK matters. This does not preclude membership of the IEM but for it to happen the future relationship would require a separate dispute resolution body to be formed or adopted and full adherence to the present market acquis and advanced market rules. This is the position Norway has taken as a non-EU member to participate fully in the IEM but Switzerland, for example, has failed to meet all the requirements to be included in the XBID process or the day ahead market coupling.

In a Brexit scenario where GB were to leave its current and future implicit market coupling arrangements then a reversion to explicit market coupling would take place or a new arrangement formed and it is unclear whether the GB market would still have access to the interconnector flow forecasting platform administered by Coreso, which is implemented under EU legislation [73]. This would inevitably lead to a less efficient overall utilisation of interconnector assets with increased levels of reverse flows and associated negative impacts on GB energy prices. As noted in section 2.2, the cost benefits of market coupling at a European level have been estimated to be over €2bn/yr for day ahead and intraday coupling combined which suggests the costs of market uncoupling for GB could potentially be significant.

As well as potentially reducing the operational efficiency of existing and future interconnector capacity, Brexit also has potential implications for their contribution to security of supply issues. In recent years, interconnectors have been allowed to participate in the GB capacity market. Changes to the market coupling arrangement would likely have implications for the determination of the requirements of the capacity market and de-rating factors that are applied to interconnector projects within it. Furthermore, it is a long-term aim to allow non-GB generators to participate in the capacity market but work towards such a goal would only be hindered by GB no longer participating in the IEM.

9. Conclusions

This paper has sought to provide an extensive analysis of the technology, market and regulatory issues related to the development of large scale interconnector projects and how these considerations interact. A comparison of the available technology options concludes that HVDC technology is required or preferred in many interconnection scenarios and that the choice of HVDC converter technology has potentially significant bearing on the services that can be provided via the interconnector. VSC converter technology offers the greatest functionality and increases the potential for interconnectors to operate in what are likely to be increasingly important ancillary service markets whilst the more established LCC technology still has a slight advantage in terms of maximum rated voltage and capacity.

The paper underlines the market principles that drive interconnection expansion and discusses the various governance models and revenue streams that are available and highlights a growing trend towards market integration which aims to improve the efficient utilisation of interconnectors. The investment case for interconnection is explored highlighting the need for diversity between the connected markets and discussing the how ancillary service opportunities available to and offered by interconnectors could become an increasingly important component of the business model.

A quantitative summary of HVDC projects is provided along with a comprehensive qualitative analysis of the potential impact of interconnector projects on eleven key stakeholders, differentiating between the impacts in importing and exporting areas. This then informs a more detailed discussion of potential policy implications, discussed through the lens of the GB system.

The analysis highlights the increasing need for interconnector projects to be considered within a broader context than simply the financial viability of the interconnector itself in increasingly integrated energy markets and outlines the benefits that they can potentially bring. It also shows that they can have a significant impact on an array of stakeholders and that policymakers should be careful to understand that the addition of interconnectors can lead to both winners and losers and that the impacts can vary over time given changing background system and market conditions. It can be argued that a total social welfare approach to determining interconnection value is a more valid approach than the current GB focus on consumer welfare only. Careful consideration of whole system impacts is also required and there is a need for a strong regulatory framework and international cooperation to ensure end goals such as increased security of supply, ancillary service provisions and reduced carbon emissions can be met via interconnection.

Finally, the implications of the UK's withdrawal from the European Union – "Brexit" – are discussed and it is shown that there are very strong incentives for Britain to stay within or as closely aligned to the IEM as possible to allow for the full benefits of interconnection to be unlocked.

Credit author statement

Callum MacIver: Writing – Original Draft, Writing – Review & Editing, Methodology, Formal Analysis, Investigation, Visualization, Data Curation. Keith Bell: Writing – Original Draft, Review & Editing, Conceptualization, Methodology, Funding Acquisition, Supervision. Grain Adam: Writing – Original Draft, Writing – Review & Editing, Methodology, Investigation, Visualization. Lie Xu: Writing – Review & Editing, Conceptualization, Methodology, Supervision.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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