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Batteries and interconnection: Competing or complementary roles in the decarbonisation of the European power system?

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A B S T R A C T

Significant increases in renewable energy are needed in electricity systems in order to reduce greenhouse gas emissions, particularly in the face of increasing electricity demand arising from the electrification of heat and transport. Greater flexibility is required in the electricity system to facilitate this, using proven flexibility providers such as batteries and interconnection or new technologies yet to be proven. This paper investigates how the relationship between battery and interconnection development and carbon price can impact carbon dioxide emissions and renewable energy curtailment. The study simulates twenty-eight scenarios and sensitivities using a unit commitment and economic dispatch model of a 2030 European power system that acknowledges that coal will not be fully eliminated from the 2030 generation mix. The results show that interconnection and battery deployment can alleviate renewable energy curtailment by over 2.4 TWh for the basecase, but a high carbon price is critical to ensuring their deployment plays a complementary role in reducing emissions. The paper also examines the impact of batteries and interconnection on solar and wind energy curtailment. It reveals that battery development nearly doubled the solar energy benefits achieved by interconnection development in some cases, while wind energy benefited more from interconnection development.

1. Introduction

The Paris Climate Agreement 2015 signifies a unity of purpose among the 196 signatories towards reducing peak Greenhouse Gas (GHG) emissions. The latest United Nations (UN) Intergovernmental Panel on Climate Change (IPCC) report details the climate changes that have already been witnessed due to global warming of 1 °C above pre-industrial levels. It also highlights the stark reality that to limit global warming to a 1.5 °C requires net zero CO_2 emissions globally circa 2050 and concurrent extensive reductions of other GHG emissions [1]. The European Union has established the European Green Deal (EGD) that includes a GHG emissions reduction of 55% by 2030 relative to 1990 levels [2]. The EGD deems this necessary to stay on course to achieve be a climate neutral continent by 2050. There are many aspects of the EGD, including increases in Renewable Energy Sources (RES) in every sector from transport to heat to agriculture and forestry [3,4].

Increased electrification met by carbon free electricity presents an opportunity to reduce emissions [5] and expedite decarbonisation in sectors such as transport, heat and industry. The share of electricity in final energy demand is expected to increase from 19% today to at least 55% by 2050 [6]. Generation from RES in the European electricity sector has increased from 16% of final electricity consumption in 2005 to 34% in 2019 [7] and is likely to continue to increase significantly [8]. Nevertheless, highly emissive fossil fuels will still feature in the generation mix in 2030 albeit to a smaller extent (typically ~5% generation) [9–11]. Completion of phase-out plans for the EU countries most heavily reliant on coal for power production is over a decade off or yet to be finalised: Germany in 2038 [12], Romania in 2032 [13], Czechia the end date is yet to be decided, and Poland currently does not have a formalised plan.

Higher penetration of RES in electricity systems will require greater system flexibility than today [14,15]. This additional flexibility could be provided by interconnection to other power systems which shifts electrical power geographically [16]. Resources such as Demand Side Response (DSR), batteries and Power-to-Gas (P2G), all of which effectively shift demand and/or generation in time, could also provide additional flexibility. Power-to-gas (P2G) is gaining traction as a potential technology to leverage surplus renewable generation and provide such flexibility with some studies showing that it may feature in the

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Nomenclature

Abbreviations

ATC	Available Transfer Capacity
BTM	Behind the meter
CCGT	Combined Cycle Gas Turbine
CO_2	Carbon dioxide
DSR	Demand Side Response
ENTSO-E	European Network of Transmission System Operators of Electricity
ESMA	European Securities and Market Authority
EU	European Union
GHG	Greenhouse gas
IPCC	Intergovernmental Panel on Climate Change
MILP	Mixed integer linear programme
OCGT	Open Cycle Gas Turbine
P2G	Power to Gas
PV	Photovoltaic
RES	Renewable Energy Sources
SEM	Single Energy Market
SRMC	Short Run Marginal Cost
TSO	Transmission System Operator(s)
TYNDP	Ten Year Network Development Plan
UN	United Nations
VRE	Variable renewable energy
V2G	Vehicle to grid
VRES	Variable renewable energy sources

Units

GJ	Gigajoule
GW	Gigawatt
GWh	Gigawatt hour
MW	Megawatt
MWh	Megawatt hour
t	tonne
TWh	Terawatt hour

electricity mix in 2050 [17]. However, for the timeframe out to 2030 it is essential to explore how technologies that are proven and are ready to deploy can assist in ensuring that emissions reduce as quickly and efficiently as possible. This mitigates the risk of new technologies failing to mature quickly enough, as the sooner that emissions peak and start to decline the less onerous the task is later [18].

Researchers have observed that increased decentralisation is an inevitable component of the energy transition [19,20]. In previous work we suggested four possible future visions of electricity systems starting with a centralised system with distributed generation and other options having increased decentralisation up to a fully decentralised system [21]. With increasing renewables penetration driving decentralisation and a push towards centralisation through increased interconnection between countries and electrically islanded systems [22], the most likely vision for the pan European power system will be a mix of centralised and decentralised but the proportions of that mix are unknown.

This work fills a gap in the literature by exploring the relationship between carbon price and the development of interconnection, a centralised technology, and batteries, a technology which can be considered centralised or decentralised depending on scale and location. The study considers a 2030 European power system base scenario, capable of achieving the emissions reduction in Europe to limit global temperatures to 1.5 °C, proposed by the European Network of Transmission System Operators of Electricity (ENTSOE) in the latest Ten Year Network Development Plan (TYNDP) [23]. It is a scenario that acknowledges that fossil fuels will still feature in the energy mix in 2030. We examine the effect of increasing interconnection and increasing battery deployment on emissions and curtailment for the target year. We conduct several sensitivities to provide extra depth to the analysis. Uniquely, the study highlights how each technology affects curtailment of wind and solar and not just total Variable Renewable Energy (VRE) curtailment. A strength in our approach is that we consider a policy relevant scenario for the year 2030 that is consistent with emissions reduction targets and expected growth of electricity demand in sectors such as transport and heat. A weakness in our approach is that we examine one year (2030) only, and so longer intertemporal effects are ignored and the pathways to and beyond 2030 are not examined.

This paper is organised in five sections. In section 2, a literature review is presented highlighting the contributions of this work. The data and methods used in the study are described in Section 3. In section 4, the results are presented and discussed, followed by a conclusion in section 5 and future work in section 6.

2. Literature review

The history of cross-border interconnection in Europe goes back to the 1920s [24]. The flexibility provided by interconnection is in the ability to leverage generation and demand resources from the connected power systems. Due to the larger geographic areas covered by interconnected systems there can be a smoothing effect on the variability of demand and renewable energy such as wind and solar [25]. In addition to leveraging diverse generation portfolios, interconnection offers the opportunity to increase the integration of renewables, share reserves between the interconnected parties and lower overall system investment and operating costs [26]. However, projects may take many years if not decades to develop for a variety of reasons including public opposition [27].

Batteries have a long history yet the use of grid-scale batteries in electricity systems is a more recent development [28]. Globally, utility scale installations accounted for two thirds of total battery capacity added in 2020 and across all battery installation sizes lithium-ion continued to be the dominant technology. Despite the global trend, there was a reduction in utility scale installations in Europe in 2020 but there was strong growth in BTM installations, particularly in Germany [29]. Anecdotally, the timeline from application to completion of large commercial and utility scale batteries in the UK is typically 18 months [30]. Although, this likely varies from jurisdiction to jurisdiction, large scale BESS projects can usually be deployed in a much shorter timeframe than cross-border interconnection and BTM batteries in an even shorter timescale again.

Suitably located batteries can defer network investments by managing network congestion. In particular, the benefits of batteries located in the low voltage (LV) grid, which are typically BTM, go beyond the low voltage level to medium and high voltage levels [31]. In addition to assisting in energy balancing, batteries can provide system services such as blackstart capability, frequency regulation and flexible ramping [28] and when co-located can be used to firm renewable generation capacity. Historically, battery costs have been prohibitively high, but in recent years there has been significant cost reductions. This downward trend in costs is forecasted to continue for many battery technologies including lithium-ion batteries [32].

The choice of power system modelling approach depends on the study objective as well as the perspective being considered. For gaining an understanding of the implications of short-term changes in a power system, Marginal Emissions Factors are useful. They are determined using historical data and reflect the intensity of marginal generation to a change in system demand. However, when considering future power systems where significant changes are expected in the generation mix, the usefulness of MEFs based on historical data is limited. The significance of examining the impact of storage on emissions [33] and the impact of storage on emissions depending on the generation mix have been demonstrated [34] using MEF studies previously. The role of interconnection was not a key aspect of these works and comparisons of storage and interconnection in terms of impact on curtailment and emissions were not performed. The significant role of interconnection in facilitating higher penetration of VRES is highlighted in Ref. [35], which conducts a statistical analysis of historical data, however storage is not a feature of the study.

For studies looking at more significant changes to the power system, an optimization model could be used. These normally have a single objective, for example to minimise overall cost. Unit Commitment and Economic dispatch (UCED) and capacity expansion planning studies are typical optimization models. A UCED study identifies when generators should start up and shut down and the output of each generator and input/output of storage at each time interval to meet electricity demand subject to operational constraints. They are typically used for short to medium term operational planning and have high temporal resolution. If provided with exogenously determined future generation and transmission capacities, as we have in this work, a UCED study can be used to explore power system operation many years in the future whether it has been optimally developed or not. A capacity expansion planning study is used to determine the optimal investment in generation, storage, and grid, to ensure the power system meets specific reliability requirements over the long-term, considering a set of defined expansion options and assumptions on future fuel prices, technology costs, generation end of life dates and electricity system demand amongst others. Typically, capacity expansion planning studies have lower temporal resolutions than UCED only studies and use time slices to capture seasonal effects. The investment cost assumptions used in a capacity expansion model can strongly influence the development of the optimal portfolio.

Capacity expansion planning studies have previously been used to investigate interconnection and storage. Knezovic et al. presented an expansion study on a '*reduced representative*' pan European system. The work combined a typical capacity expansion planning approach with a UCED model to capture the optimised weekly operation cost for 8 representative weeks per investment step over a 40-year time horizon. The study concluded interconnection is the most economic option for integrating large amounts of VRE sources (VRES) [36]. Another capacity expansion study focused on 5 countries in the Continental European grid. The methodology was also a combination of a capacity expansion planning tool with a UCED with hourly time resolution. To reduce complexity, however, detail that would typically be included in a standalone UCED was omitted such as minimum generation levels [17].

Unlike traditional capacity expansion models which consider existing transmission and generation assets, Bussar et al. adopted a greenfield investment approach. An evolutionary strategy is used to identify the optimal mix of technologies for each of the 21 regions considered in the larger geographic area of Europe, the Middle East and North Africa, to minimise both operation and investment costs. The work examined how different technology mixes and constraints impact the least cost 100% renewable electricity system for 2050 and highlighted how constraints on cross-border interconnection capacity or long duration storage can significantly increase costs [37].

Steinke et al. determined the optimal level of storage to minimise backup energy requirements for different grid connection levels, ranging from local level to the perfect European grid, for a 100% renewable European electricity system. The novel but simple approach adopted was to scale up installation capacities so that at a regional level wind met 65% and solar met 35% of annual electricity consumption and for each grid size identify the level of back up energy to meet the residual demand using a single optimization. Secondly, for the smallest grid size (50 km by 50 km), storages with different durations were considered to reduce the backup energy demand. Existing cross-border interconnection was not considered, and it appears that hydro generation is not included in the study. Wind and solar data with high spatial resolution was used to determine wind and solar generation profiles. Albeit the benefit of this was limited by the lack of similar resolution for the capacities of wind and solar and the system demand time series, which had to be assumed to be uniformly distributed from national/control region values to match the higher resolution wind and solar data. An economic analysis of grid and storage options was also performed. Besides storage in the form of pumped hydro, hydrogen or batteries, other potential backup energy providers were not explicitly included in the optimization or economic analysis, although biomass, coal and gas were briefly mentioned in the discussion section [38].

Child et al. using a bottom-up techno-economic energy system model examined if a centralised or decentralised approach resulted in the best solution for a 100% renewable European electricity system and suggested that a hybrid approach may be the most beneficial option. A larger geographic area than our study was represented in the model but with fewer nodes. Two scenarios were considered, one with interconnection between regions and one without [39].

Notably, in the literature that has investigated batteries and interconnection, there is a focus on 2050 [37], complete decarbonisation [17], and 100% RES-E [37–39]. These studies are useful for policy makers to understand optimums and ideals in the long-term. In 2030, coal phase out across Europe will not be complete. Technology options for meeting demand at times of low RES-E in some studies tend to omit fossil fuels such as natural gas and/or coal completely from the models [17,37] or else consider backup energy as a whole within the model without explicitly modelling the individual fossil fuel technologies that may be included in meeting that backup energy [38]. The next decade has been recognised as crucial in the fight against climate change [1,40] and by then RES-E will be closer to 60% rather than 100% in Europe. Thus, focussing on the year 2030 is of great importance. The studies examined that did include coal the energy mix for the transition year 2030, only used a small number of representative weeks rather than a full year and did not discuss 2030 in detail [36] or limited the investigation of cross-border interconnection to zero or optimum levels [39]. Development by investors in a liberalised electricity market adopting a profit maximisation approach may not result in the optimum renewable and storage mix unless the correct market structures are in place [41]. Furthermore, none of the studies investigated the impact of different carbon prices on the role of interconnection and storage as our study does. Thus, our work fills a gap in the literature as it compares interconnection and storage on a like for like basis for a scenario focussing on the year 2030 that still features fossil fuels. Moreover, it investigates this for the optimum situation of a power system where the grid, renewable and thermal portfolio have been optimised and a suboptimal one.

Increased investment in renewables will be required if increased demand due to electrification is to be met by renewables. Curtailment, which is effectively lost energy, is a risk of increasing importance for investors in renewable energy technologies [42]. Utilising curtailed energy and minimizing the amount of curtailment is an active area of research. Researchers have investigated using curtailed energy for hydrogen production [43], off-grid applications [44], reducing emissions associated with EV charging [45], mitigating curtailment by shifting load between data centres [46]. The mix of wind and solar in a power system is important as they are not closely correlated. Thus, having solar in the renewable energy mix along with wind takes advantage of their natural complementarity [47] and can assist in reducing VRE curtailment [25]. With increasingly renewable systems it is reasonable to assume that there will be some increase in renewable curtailment and the case has been made for managing curtailment rather than minimizing it [48]. Understanding how these different flexible technologies (interconnection and battery storage) may impact on curtailment of different renewable technologies is important for policy makers that may be targeting a particular renewable technology mix in the future. This study compares the impact of interconnection and battery deployment on wind and solar curtailment rather than focussing on the impact on one technology or total VRE curtailment.

In summary, this work fills a gap in the literature for three reasons. Firstly, it investigates the impact of different carbon prices on the role of batteries and interconnection in decarbonisation of the European power system. Secondly, it focuses on the year 2030 in detail, with a policy relevant scenario that includes coal, and considers the optimum situation of a power system where the grid, renewable and thermal portfolio have been optimised and a suboptimal one. And thirdly, to the best of the author's knowledge, this paper presents the first differentiated analysis of the impact of flexible technologies on curtailment of individual renewable technologies in the literature. Additional novelty is found in the results, which reveal that battery development benefits solar energy more, while wind energy benefited more from interconnection development.

3. Data and methods

In this section the data and methodology utilised to explore the relationship between battery and interconnection development and carbon price are described.

3.1. Selection of base scenario

The ENTSOE is the association ensuring co-operation of TSOs in Europe. Its mission is to ensure "*security of the interconnected power system in all time frames at pan-European level and the optimal functioning and development of the European interconnected electricity market*" [49]. In fulfilling this function, ENTSOE publishes a TYNDP every 2 years. As each TSO feeds into the development of TYNDPs and the draft plans are subject to public consultation, the plan is a comprehensive set of perspectives of development of the pan European power system.

For this study the 'Global Ambition' scenario, which aligns with the 1.5 °C ambition of the Paris Climate Agreement, was selected as the base scenario. It reflects a pan European power system achieving approximately 60% RES-E, with significant renewables build out and an improved interconnection and battery capacity relative to current levels. The cross-border transmission capacities of the 'Expanded Grid' in the ENTSOE scenario data files were used. This 'Expanded Grid' along with the renewable and thermal capacities in the Global Ambition scenario are the outcomes of an optimization process bounded by a maximum annual emissions level. For the rest of this paper the 'Expanded Grid' will be referred to as the enhanced grid.

3.2. Model

An hourly power systems model of the pan European power system was used to analyse the impacts of modifying interconnector import capacity and battery capacity over the target year. The model synthesised the ENTSOE Global Ambition scenario using Energy Exemplar's *PLEXOS ® Integrated Simulation Software* [50]. The base scenario utilises the generation, DSR and interconnector capacities as well as electricity demand and fuel prices from the 'Global Ambition' scenario in ENTSOE 2020 TYNDP for the year 2030.

Disaggregated electricity demand time series for electric mobility and heating or assumed volumes of heat pumps and electric vehicles by country were not available for any of the ENTSOE 2020 TYNDP scenarios, which impeded the authors directly modelling the flexibility of these assets within this study. However, electric heat and smart charging are modelled implicitly within the Global Ambition scenario demand profiles used as the impact of temperature and electric vehicles are endogenous with "*an inherent level of smart charging that shifts consumer behaviour away from peak periods*" [51].

In this work each country is represented as a single node as shown in Fig. 1. Similarly, multiple cross border interconnectors between countries are modelled as a single line with a combined transmission capacity to reduce computational complexity in the model. As grid congestion within countries is not modelled in this study, the locational impact of batteries and interconnectors is not captured within this analysis. It is also assumed that the Available Transfer Capacity (ATC) of interconnectors does not deviate from the maximum values.

The objective function within the model seeks to minimise the total

Fig. 1. Map of interconnection in model.

generation costs while meeting demand across the entire system and respecting the technical and operational constraints included in the model. The problem is formulated as a mixed integer linear programme (MILP). The model resolution is hourly with a rolling 24-h horizon. Generator heat rates, minimum on/off times, minimum stable levels, ramp rates, CO_2 costs, fuel costs and generator start-up costs are all considered within the optimization. Due to the complexity of the European power system and to reduce problem solving time, generator characteristics were standardised per generator type as indicated in Table 1. Eleven generator categories were included in the model: biofuels, natural gas Combined Cycle Gas Turbine (CCGT), natural gas Open Cycle Gas Turbine (OCGT), hydro-generation, nuclear, lignite, hard coal, oil, other non-renewable energy sources (NonRES), wind, solar and other RES. Similar approaches were adopted in previous studies [52,53].

Fossil fuel fired generator efficiencies are provided in Table 2 and are within the ranges of those provided in the TYNDP [54].

Direct CO_2 emissions from fuels are captured within the model and the emissions factors are based on those published by the Sustainable Energy Authority of Ireland [55] and are aligned to those in the 'IPCC 2006 Guidelines for National Greenhouse Gas Inventories' [56]. The model simulation has perfect foresight and competitive bidding behaviour was not included in the analysis so that power stations are dispatched based on their short-run marginal cost (SRMC). The fuel prices used were taken from the ENTSOE 2020 TYNDP [57] and are shown in Table 3 below.

Wind is modelled as two generators at each node with aggregated capacity for offshore and onshore wind. No distinction is drawn between ground-mounted or roof-mounted solar Photovoltaic (PV), which like wind is modelled as one generator with aggregated capacity. As is often the case in real time system operation, wind, solar and hydro are not assigned any marginal costs and effectively act as price takers within the model. The normalised wind and solar profiles used in this analysis were based on historical data available in ENTSOE Pan European Climate Database [58]. For hydro-generation, country specific monthly capacity factors based on average historical outputs available from ENTSOE Transparency Platform were used [59].

The operation of BTM batteries is often optimised to minimise the consumers' costs rather than the system costs. In the model, we do not distinguish between BTM and utility scale batteries as research has shown that aggregation of BTM batteries results in greater savings for all consumers and reductions in wholesale electricity prices [60]. Instead, we assume that the BTM batteries are grouped to make the aggregated capacity of a grid scale battery. Battery characteristics are standardised with a typical maximum power of 100 MW, a 3-h duration, and an efficiency of 90%. Like renewables, batteries in the model are not assigned a marginal cost as the study is seeking to understand their potential impact on decarbonisation when dispatched to minimise system costs. While batteries can be deployed to reduce network investments as well as providing a range of system services such as frequency containment reserve and ramping, these were not considered in this work. It is worth noting that the cost saving in deferring network investment that can be achieved by deploying batteries, particularly at LV, can be significant. For example, a BTM storage project was considered by New York utility, Con Edison, as an alternative to a US$ 1.2bn substation upgrade [28]. To quantify the cost saving of deferred network investments the location and size of storage within the grid would have to be quantified and costed and compared to the cost of the alternative of network expansion and/or substation upgrades. This would require detailed modelling of the existing and forecasted transmission and distribution networks including substation component ratings within each country. Due to the geographic scale of this model, it is outside the scope of this work.

Table 1
Standard generator characteristics.

Generator Type	Capacity (MW)	Start Cost (€/Start)	Minimum Stable Factor[a] (%)
Biofuel	300	10,000	30
Natural gas CCGT	450	80,000	40
Natural gas OCGT	100	10,000	20
Hydropower	200	0	10
Nuclear	1200	120,000	50
Lignite	300	80,000	30
Hard Coal	300	80,000	30
Oil	400	75,000	40
Other NonRES	300	5000	30

[a] Minimum stable factor is the level of generation required to maintain stable operation expressed as a percentage of the Max Capacity of the unit.

Table 2
Standard efficiency of generators used in model.

Fuel/Generator Type	Standard Efficiency in NCV terms (%)
Coal	40
Lignite	40
Gas - CCGT	51
Gas - OCGT	35
Nuclear	33

Table 3
Fuel Prices used in the analysis.

Fuel	Price (€/GJ)
Lignite	1.1
Natural Gas	6.91
Hard coal	4.3
Nuclear	0.47
Heavy Oil	14.6

3.3. EU carbon price

The EU carbon price saw an almost threefold increase in 2021 from approximately €30/tCO_2 to nearly €90/tCO_2. This rapid rise led to the European Commission requesting the European Securities and Market Authority (ESMA) to investigate trading patterns and the functioning of EU carbon markets in October 2021. So far in 2022 the volatility in carbon price has not abated, a record carbon price of €96/tCO_2 reached in February 2022 followed by a significant dip in March 2022 to below €60/tCO_2 even though gas prices were at record highs [61,62]. While the report did not find any significant anomalies during the period analysed, it has made several recommendations to make it easier to form a complete understanding of the EU carbon markets and improve transparency [62].

Researchers have identified several variables that impacted historical carbon prices including gas, coal and oil prices, seasonal trends, policy changes in addition to speculative shocks [63]. The war in Ukraine and associated speculation around gas shortages undoubtedly has added to market jitters but it is only in time that this effect can be quantified. While carbon prices are likely to stay around the current average for the foreseeable future [62], carbon prices many years in the future are more difficult to forecast. As this study considers the year 2030 two carbon prices were considered, a low and a high carbon price. The low price represents a situation where carbon prices return closer to the historical long-term average pre 2020 with a price of €35/tCO_2 in line with the ENTSOE TYNDP 2020 Global Ambition scenario data, this is included in the basecase. The high carbon price represents a situation where carbon prices increase from the 2022 year-to-date average to €100/tCO_2, which is investigated in the sensitivities described further in the next section.

3.4. Model simulations

All model simulations were performed on a Dell Intel(R) Core (TM) i5-6300U CPU @ 2.40 GHz. The solver used was Xpress-MP 35.01.01. The average runtime per simulation was 01:20:40. In total 28 model simulations were carried out. This included the basecase plus six scenarios, three with increasing interconnection and a further three scenarios with increasing battery capacity as shown in Table 4. For all simulations there is no change in the thermal generation portfolios. The step increase in both the interconnection and battery scenarios was equal to 5% of the power system demand peak for the year 2030 for each country. The only exception to this was for Ireland and Northern Ireland which make up the Single Energy Market (SEM) on the island of Ireland. This was treated differently in that the interregional transmission capacity between Ireland and Northern Ireland was included in the model but only the capacities of interconnectors to neighbouring electricity systems (France – Ireland, Great Britain – Ireland and Great Britain – Northern Ireland) were increased for interconnection scenarios. Three sensitivities were carried out on all scenarios: (1) a high carbon price, (2) a 10% increase in wind and solar capacity and (3) a high carbon price combined with a 10% increase in wind and solar capacity. The first was to determine how the relationship between interconnectors and batteries may change with a higher carbon price. The purpose of the latter two sensitivities was to investigate if the trends changed when the cross-border interconnection capacity was not enhanced to cater for the renewable portfolio within each country.

As the focus of the paper is on batteries and interconnection it was important to avoid the effects of other generation categories obscuring the results. Thus, the profiles produced in the basecase for Biofuels and Other Non-RES, representing 2% and 7% of the generation mix, were provided as an input to all the subsequent simulations and sensitivities.

4. Results & analyses

In the following subsection, the impacts of the sensitivities on the basecase are discussed. This sets the context for the other cases where interconnection or battery capacity is increasing. The basecase reflects a power system that has high levels of RES yet still retains elements of conventional and fossil fuel generation for backup generation when renewables alone cannot meet demand. It reflects a power system where the grid, renewables and thermal portfolio have been optimised with emissions being limited in line with the requirements under the Paris Agreement. The other cases with increasing battery and interconnection capacity are then analysed in the following subsections under the headings of emissions and curtailment. This is followed by a discussion on flexibility that electric vehicles and power-to-offer.

4.1. Basecase and impact of sensitivities

The sensitivities show the impact of changing aspects of the basecase including the CO_2 price, an increased variable renewable portfolio, and a combination of thereof. The high CO_2 price in the basecase causes coal to gas switching with a decrease in production from solids fuelled generation (i.e., coal and lignite) across Europe and an increase in production from more emissions efficient gas generation. Adding 10% VRES capacity to the basecase reflects a situation where the grid is no longer enhanced for the renewable capacity installed. In this sensitivity wind and solar displace flexible gas generation with generation from solids reducing to a much lesser extent. When there is both a high CO_2 price and 10% additional VRES capacity, production from solids fuelled generation reduces significantly with an increase in production from gas (Fig. 2).

Corresponding with the change in production by fuel mix there is a reduction in emissions across all the sensitivities when compared with the basecase as shown in Fig. 3. A high carbon price makes significant impacts on emissions with reductions achieved by 'High CO_2 Price' and 'High CO_2 Price plus 10% VRES' being over 1.5 and 2.5 times the reduction achieved by increasing VRES capacity by 10% alone.

The high CO_2 price also results in a reduction in curtailment. With 10% increase in VRES capacity there is a significant relative increase in VRES curtailment reflecting the impact of the grid, thermal and renewable capacities not being collectively optimised. A higher CO_2 price in addition to increased VRES capacity mitigates this increase by 30.5%.

This analysis of the results confirms that for power systems with fossil fuel fired generation, a high CO_2 price will reduce emissions and VRE curtailment. It is worth noting, however, that a high CO_2 price without the correct market design is unlikely to lead to a decarbonised reliable electricity system [41].

4.2. Emissions

With the impact of the sensitivities on the basecase set out, it is possible to distinguish between the impact of the sensitivity and the impact of increasing batteries and cross-border interconnection capacity within each sensitivity. The proven flexibility offered by batteries and cross-border interconnection will be required to facilitate the transition to a net zero energy system and it is critical to understand the impact of these technologies on emissions.

In the basecase the cross-border interconnection capacity is enhanced for the renewable and thermal capacity installed. When no sensitivity is applied to the scenarios, it reflects the situation of an enhanced grid and Fig. 4 (Sensitivity = None) shows that increasing interconnection may increase emissions slightly. This reflects the fact

Table 4
Overview of simulations and sensitivities carried out.

Simulation	Difference from Basecase	Sensitivity 1	Sensitivity 2	Sensitivity 3
Basecase	–	High CO_2 Price	Plus 10% VRES (wind and solar) capacity	High CO_2 Price plus 10% VRES (wind and solar) capacity
Interconnector 5% (IC5)	IC capacity increased by 5% electricity system demand peak per country			
Interconnector 10% (IC10)	IC capacity increased by 10% electricity system demand peak per country			
Interconnector 15% (IC15)	IC capacity increased by 15% electricity system demand peak per country			
Battery 5%(Bat5)	Battery capacity increased by 5% electricity system demand peak per country			
Battery 10% (Bat10)	Battery capacity increased by 10% electricity system demand peak per country			
Battery 15% (Bat15)	Battery capacity increased by 15% electricity system demand peak per country			

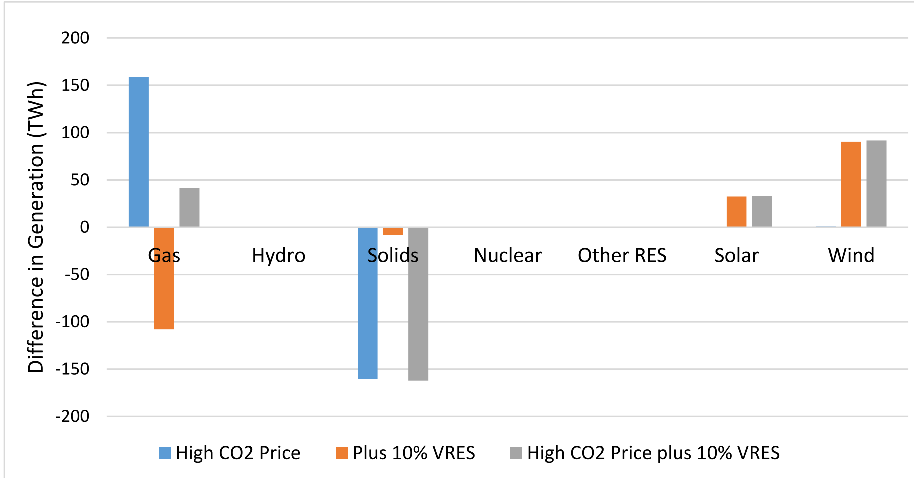

Fig. 2. Difference in production by fuel type compared to basecase for each sensitivity.

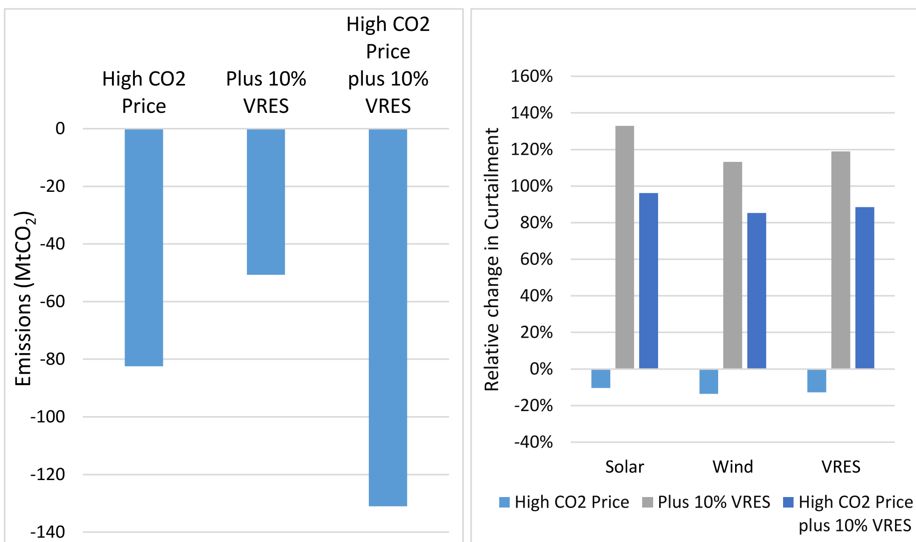

Fig. 3. Change in emissions and relative change in curtailment for the sensitivities relative to the base scenario.

that increased interconnection facilitates increased production from cheaper but higher emitting solid fuelled generators (Fig. 5).

For both high CO_2 price sensitivities (i.e., High CO_2 Price and High CO_2 Price plus 10% VRES) increasing battery capacity or increasing interconnection capacity decreases emissions compared to the corresponding sensitivity on the basecase. The results show that with a high CO_2 price both technologies reduce emissions across the modelled European power system with interconnection outperforming batteries on a megawatt for megawatt capacity basis (Figs. 4 and 6). Given that the study increases capacity of these technologies by percentage of peak system demand by country, it is reasonable to assume that optimal placement and sizing would lead to even greater emissions reductions.

The incremented capacity of cross-border interconnection and battery storage in this study was necessary to understand the relationship between CO_2 price and the roles that batteries and cross-border interconnection can play in the decarbonisation of the European power system. Realistically, all countries could not increase cross-border interconnection capacity by such proportions by 2030 especially given the long timeframe to complete these projects, but some countries will. The increase of battery capacity by 15% of power system peak demand across Europe would require a significant financial investment and could not be justified on the basis of the emissions reductions alone which were less than 4MtCO_2 in this study. It would only proceed if jusitified on the basis of the complete range of benefits that batteries can provide to the power system including energy/demand shifting, frequency regulation, ramping, deferal of network investments, congestion relief and blackstart services. Some countries/jurisdictions are more likely to see such battery and interconnection capacity increases than others. Following a survey of its members, the representative body for the energy storage industry on the island of Ireland, Energy Storage Ireland, confirmed that there is over 2.3 GW of battery projects in the pipeline on the island [64]. If all of these projects materialise, their capacity would account for approximately 25% of the forecasted peak electricity demand in 2030 [65]. Similarly, the capacity of three interconnection projects also for the island of Ireland, that were not captured within the basecase of our study, amounts to increases greater than 16% of forecasted peak electricity demand for the island [65–68]. The capacity of batteries and interconnection that will emerge by 2030 in each country will depend on the uptake of electric vehicles and electric heating, the needs of the power system within each region, and how national policy and market design evolves.

Another key finding of this study is that batteries, even if not optimally located, will reduce emissions even when the grid is not enhanced to suit the renewable and thermal portfolios (‘Plus 10% VRES’ and ‘High

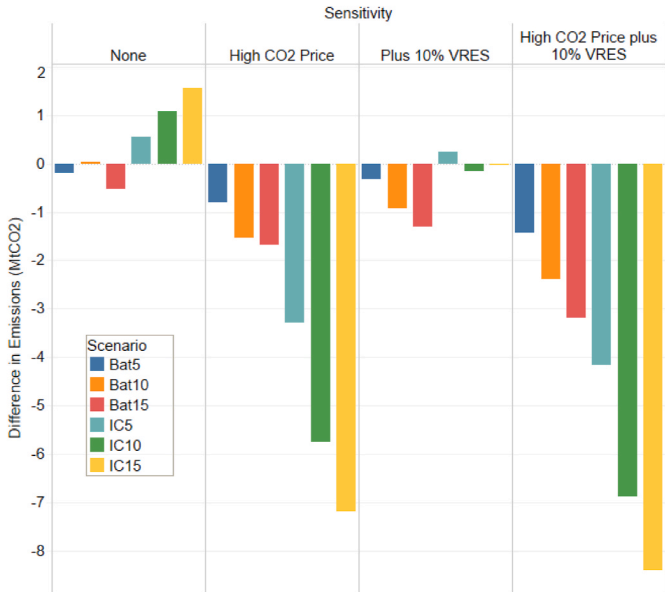

Fig. 4. Difference in emissions compared to the relative basecase.

CO_2 Price Plus 10% VRES') (Figs. 4 and 6). Given that interconnection projects take several years to complete, and assuming that deployment of batteries would not be detrimental to the business case for interconnection projects, batteries could be used as renewables are built out to reduce emissions.

There are two situations where no clear trend emerges, and the emissions impact fluctuates around zero. These are increasing battery capacity in the basecase (Fig. 4 Sensitivity = None, (Bat5, Bat10 and Bat15)) and increasing interconnection capacity for the 'Plus 10% VRES' sensitivity (Fig. 4, Sensitivity = Plus 10% VRES, (IC5, IC10, IC15)). The objective function of the model is set to minimise system costs which includes the cost of emissions influenced by the CO_2 price. For both sensitivities ('None' and 'Plus 10% VRES') the CO_2 price was at the lower level of €35/tCO_2. This coupled with the fossil fuel prices adopted in the study (Table 3) results in production and consequently emissions flip flopping between coal and gas as necessary to achieve the least cost dispatch. The highest increase in emissions for these situations relative to their base cases is 0.25MtCO_2 (Fig. 7), a small emissions figure when taken from a European wide context. Even so, it points to the need for careful planning of both the location and capacity of batteries and interconnection when the CO_2 price is not sufficiently high to guarantee that the outcome of their deployment is to cut emissions.

Examining the results has revealed that a high CO_2 price is critical to ensuring that batteries and interconnection reduce emissions in the

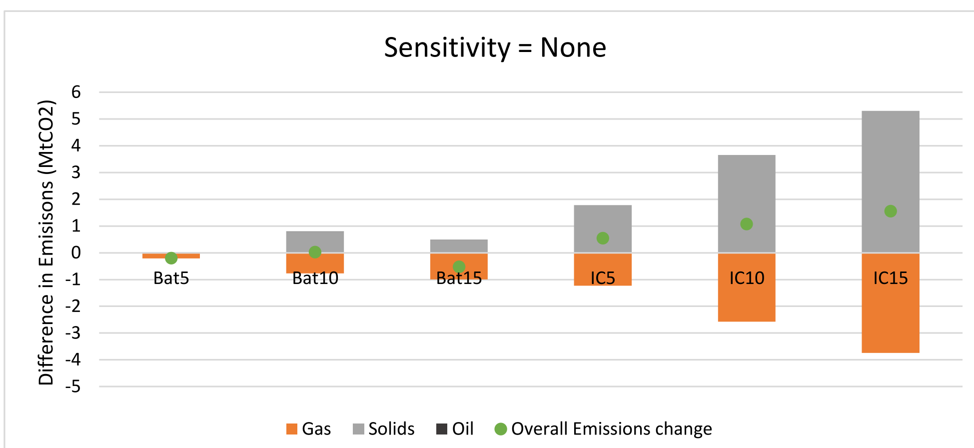

Fig. 5. Difference in emissions production by fuel type and overall emissions for scenarios with Sensitivity = None compared to basecase.

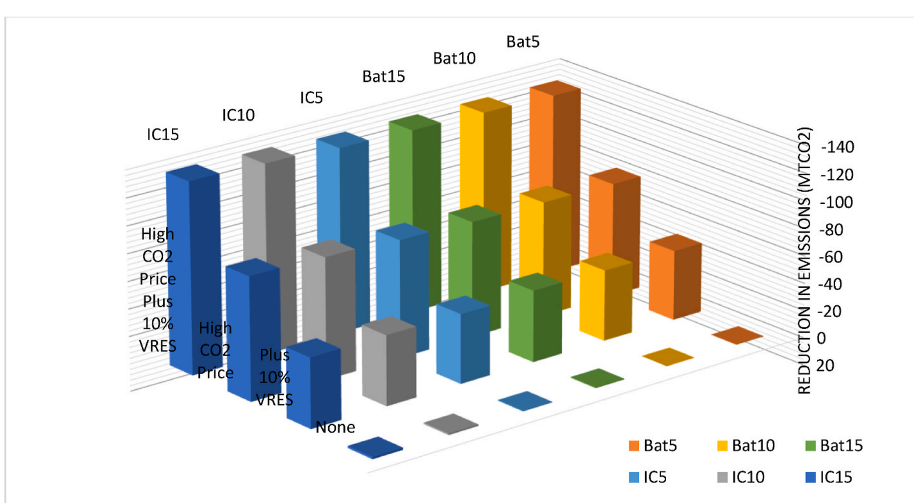

Fig. 6. Reduction in emissions by scenario for all sensitivities compared to base case with no sensitivity.

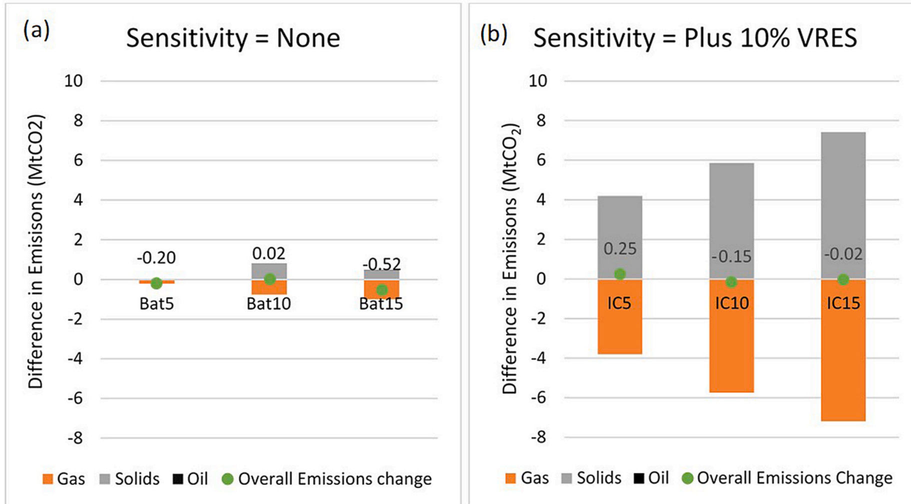

Fig. 7. Difference in emissions production by fuel type and overall emissions compared to the relative basecase for (a) No sensitivity and (b) Plus 10% VRES capacity.

European power system represented in this study, where fossil fuels still appear in the generation mix. In the next subsection the impacts on curtailment of increased battery capacity and increased interconnection capacity for the sensitivities are presented.

4.3. Curtailment of VRE

Curtailment can have a significant impact on investment decisions in renewable technologies. With increased capacity of interconnection or batteries, every sensitivity resulted in reduced variable renewable curtailment (Fig. 8). This is useful for policy makers seeking to achieve a specific renewable energy target within the electricity sector. However, as seen in the last section this did not automatically translate to reduced emissions in each case.

Batteries reduced VRE curtailment when the grid was enhanced for the renewable and thermal portfolios ('None' and 'High CO_2 Price' in Fig. 8). On average increased battery capacity decreased VRE curtailment by 0.25 TWh and 0.19 TWh more than the reduction achieved by the increased interconnection for the sensitivities 'None' and 'High CO_2 Price' respectively (Table 5). Conversely when the grid was not enhanced, increased interconnection capacity decreased curtailment by on average 0.26 TWh and 0.44 TWh more than the reduction achieved by increased battery capacity for the sensitivities 'Plus 10% VRES' and 'High CO_2 Price Plus 10% VRES'.

The study shows that additional batteries and interconnection capacity can reduce curtailment by over 2.4 TWh in the basecase, but this is very small when compared to the overall total electricity consumption in Europe of over 3500 TWh. The basecase used is pertinent to this

Fig. 8. Change in VRE curtailment relative to comparable basecase and sensitivity.

Table 5
Average change in curtailment across increasing capacity by technology compared to the relative basecase.

Grid	None (TWh)	High CO_2 Price (TWh)	Plus 10% VRES (TWh)	High CO_2 Price plus 10% VRES (TWh)
	Enhanced		Not Enhanced	
Batteries	−1.91	−1.64	−4.24	−3.31
Interconnection	−1.66	−1.45	−4.49	−3.74

result, as it represents a power system with a grid, renewables, and thermal portfolio, that have already been optimised to achieve a particular emissions target. Therefore, curtailment is already significantly reduced before the incremental battery and cross-border interconnection capacities are investigated. As the model does not consider internal transmission or distribution systems, it does not capture curtailment due to network congestion within a country. It should be noted that the curtailment results in this study are consequently rather conservative, particularly for batteries which can alleviate network congestion at all voltage levels of the electricity network.

In this analysis, the changes in wind and solar curtailment for the different sensitivities have been examined. Across all sensitivities increasing battery capacity reduces solar curtailment more than increased interconnection (Fig. 9(a)). For example, where no sensitivity is applied, on average batteries achieved approximately 1.9 times the reduction in curtailment achieved by interconnection. Similarly, increased interconnection reduces wind curtailment more than increased battery capacity with one single exception for the first capacity increase and no sensitivity. There is less diversity in solar profiles across countries and batteries provide the temporal flexibility to shift curtailed solar generation to higher demand periods. Interconnection, on the other hand, provides locational flexibility and is particularly useful for smoothing wind energy by linking geographical areas together so that the diversity in wind profiles is a benefit.

Climate neutrality is an ambitious target and presents challenges and opportunities for the electricity sector. By analysing the curtailment of energy from the individual technologies of wind and solar for the different sensitivities this study has demonstrated that batteries and interconnection improve VRE curtailment. This, in turn may accelerate the development of solar and wind projects by improving the investment case for these renewable technologies. This acceleration of renewables buildout will be vital if the electricity system is to keep pace with increased demand from electrification of other sectors and at the same time improve the share of renewable electricity. A significant finding of this analysis is that batteries had a greater impact in reducing curtailment of solar and interconnection had a greater impact in reducing wind curtailment. Furthermore, neither batteries nor interconnection increased curtailment of either wind or solar in any of the sensitivities considered. Minimizing curtailment is not necessarily the optimum way to achieve a decarbonized power system [48]. Yet, curtailment is seen as a high risk to investment in renewable technologies [42]. With a requirement for increased renewable penetration in the European power system policy makers will have to find a suitable balance when it comes to curtailment.

4.4. Electric vehicles and power-to-heat

The increased demand due to electrification presents an opportunity to avail of additional flexibility for the power system by using smart charging, Vehicle-to-Grid (V2G) services and power-to-heat [69,70]. The impact on emissions for both power-to-heat and electric vehicles extends beyond the power sector, which although increases electrical demand, should reduce wider energy system emissions assuming increased renewable penetration. However, unlike dedicated flexibility assets for the power system such as interconnection and batteries, the

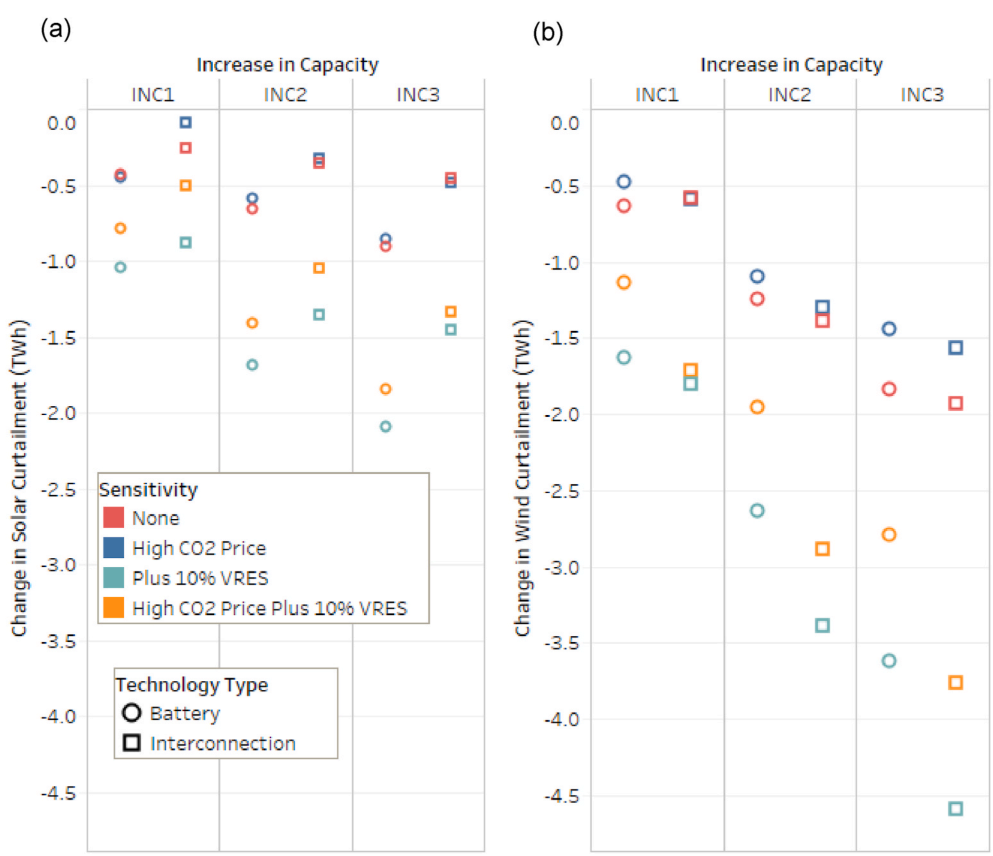

Fig. 9. Change in (a) Solar and (b) Wind Curtailment Factors relative to the comparable base case and sensitivity.

flexibility provided by electric vehicles and power-to-heat is constrained by their original main purpose, that is to provide transport and heat. For example, V2G will be limited by the times that vehicles are parked and a constraint to maintain a minimum state of charge typically higher than that of a static battery. Similarly, power-to-heat is limited in that it has to maintain comfort levels. Its ability to provide flexibility may also be seasonal and will be reduced in summer when demand for heat is lower. This study captured the impact of smart charging of electric vehicles and heat pumps, but not the full flexibility of V2G and power-to-heat. The additional flexibility not captured, even though constrained and with varying capacity, has the potential to reduce emissions and reduce curtailment. As the flexibility they provide is most similar to that of batteries, rather than interconnection, it is most likely that they may compete to some extent with batteries, but they will not irradicate the need for dedicated flexible resources in power systems.

5. Conclusion

Reducing emissions out to 2030 will be challenging but existing technologies may hold some potential to assist in the transition to net zero. More flexible technologies will be required to facilitate the transition to a decarbonized power system. Batteries and interconnection are proven flexibility providers and could form part of a path of no or least regret to decarbonisation. In addition to shifting energy from where/when there is a surplus to where there is a deficit, these technologies can provide much needed system services to ensure the power system continues to be as reliable and resilient as it is today.

The purpose of this study was to provide insights into how batteries and interconnection development interacts with CO_2 prices and how they impact carbon dioxide emissions and renewable energy curtailment. Using a unit commitment and economic dispatch model of a 2030 European power system where coal and other fossil fuels form part of the generation mix to investigate the impacts of these technologies, this study reflects the reality of the long road to coal phase-out.

With a suitable CO_2 price, batteries and interconnection have a complementary role to play in decarbonisation of the European power system. The results showed that setting a high carbon price can be the difference between these crucial flexible technologies helping or hindering emissions reductions in the European power system. In the high CO_2 price sensitivity, interconnection emerged as the lead performer in reducing emissions, but batteries also provided reductions. Without a high CO_2 price, slightly above current levels, it emerged that batteries and interconnection can hinder decarbonisation of a European power system such as the one in this study, where fossil fuels still appear in the generation mix. The level of hindrance would likely reduce should there be a lower level of fossil fuels within the generation mix, particularly coal.

The complementary roles of batteries and interconnection was also evident in the results on VRE curtailment. Across all sensitivities both technologies reduced VRE curtailment, while interconnection alleviated wind curtailment more, batteries lessened solar curtailment more. Regardless of the level of CO_2 price, careful planning of the location, capacity and operational dispatch of these technologies is needed to ensure that the outcome of their deployment is to minimise emissions.

6. Future work

A limitation of this study was that it only considered the year 2030. It is recommended to perform further studies of the years up to and beyond 2030. The model could also be extended by including system services requirements within each synchronous area which would be useful to highlight the additional benefits of interconnection and batteries that were not captured as part of this work.

7. Data availability

The input data and model are available upon request.

CRediT authorship contribution statement

L. Mehigan: Conceptualization, Investigation, Methodology, Formal analysis, Visualization, Writing – original draft. **Brian Ó Gallachóir:** Writing – review & editing, Supervision, Funding acquisition. **Paul Deane:** Supervision, Conceptualization, Validation, Visualization, Writing – review & editing, Funding acquisition.

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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