Energy 203 (2020) 117776

Contents lists available at ScienceDirect

Energy

journal homepage: www.elsevier.com/locate/energy

Renewables in the European power system and the impact on system rotational inertia

L. Mehigan [a, b, *], Dlzar Al Kez [c], Seán Collins [a, b], Aoife Foley [d], Brian Ó'Gallachóir [a, b], Paul Deane [a, b]

[a] Energy Policy and Modelling Group, MaREI Centre, Environmental Research Institute, University College Cork, Old Lee Road, Cork, Ireland
[b] School of Engineering, University College Cork, Ireland
[c] School of Electronics, Electrical Engineering and Computer Science, Queen's University Belfast, United Kingdom
[d] School of Mechanical & Aerospace Engineering, Queen's University Belfast, Ashby Building, United Kingdom

A R T I C L E I N F O

Article history:
Received 8 February 2020
Received in revised form
29 April 2020
Accepted 1 May 2020
Available online 6 May 2020

Keywords:
Rotational inertia
Unit commitment and economic dispatch
Renewable energy
Frequency stability
Ancillary services
Power system modelling

A B S T R A C T

Generation from synchronous machines in European power systems is decreasing as variable renewable energy penetration increases. Appropriate levels of system rotational inertia to ensure system stability, previously inherent in synchronous areas across Europe, can no longer be assumed. This work investigated the impact different levels of minimum inertia constraint have in Europe and in each synchronous area. Two scenarios with divergent decarbonisation ambitions were simulated for the year 2030 using a unit commitment and economic dispatch model. The key findings show that an increasing inertia constraint elevates total generation costs, variable renewable energy curtailment and carbon dioxide emissions across Europe for an ambitious decarbonisation scenario. When inertia constraints were applied to the contrasting scenario with a low decarbonisation ambition, decreases in carbon dioxide emissions of up to 49% were observed in some synchronous areas where the constraint was frequently active. The work also scrutinised the spread of inertia in the large synchronous area of Continental Europe. It emerged that some countries are likely to experience periods of low inertia even if an inertia constraint is applied at synchronous area level.

Classification

18.010 Renewable Energy Systems.
18.020 Energy Scenarios.
18.030 Large-scale Wind Integration.
18.040 Energy System Models.
19.060 CO2-emissions.

1. Introduction

The rapid and significant growth of renewable power capacity across the European Union (EU) over the last decade will continue even faster as Member States strive to reach 2030 and 2050 renewable energy and greenhouse gas emissions reductions targets [1,2]. This is forcing system operators to re-evaluate how power systems will be operated in the future as large inertia-providing synchronous machines are supplanted by variable renewable energy (VRE) sources. Intermittent sources such as wind and solar provide very limited to no rotational inertia depending on the device technology.[1] Without supplementary supports such as frequency triggered battery energy storage systems (BESS), insufficient rotational system inertia can lead to extreme frequency deviations including high rates of change of frequency (ROCOF) in the event of an imbalance between generation and demand. A high ROCOF event that exceeds the prescribed tolerances could lead to involuntary shedding of customer load, interconnectors and generation. This could ultimately result in a total system blackout.

* Corresponding author. Energy Policy and Modelling Group, MaREI Centre, Environmental Research Institute, University College Cork, Old Lee Road, Cork, Ireland.
E-mail address: l.mehigan@ucc.ie (L. Mehigan).

[1] Solar PV has no rotation mass. Modern variable speed wind turbines are not electromechanically coupled to the power system due to the AC-DC-AC power conversion process and thus the wind turbine rotor speed is not a function of system frequency, and thus there is no inherent inertial response to a failing/rising system frequency.

https://doi.org/10.1016/j.energy.2020.117776

Nomenclature

Abbreviations

AC	Alternating Current
CE	Continental Europe
CO_2	Carbon dioxide
DC	Direct Current
ENTSO-E	European Network of Transmission System Operators of Electricity
ERCOT	Electric Reliability Council of Texas
EU	European Union
FFR	Fast frequency response
GB	Great Britain
HVDC	High Voltage Direct Current
IEM	Integrated energy model
MC	Marginal costs
MILP	Mixed integer linear programme
NCSO	Network Code of System Operation
PV	Photovoltaic
RES	Renewable Energy Sources
SRMC	Short Run Marginal Costs
ROCOF	Rate of Change of Frequency
SNSP	System Non-synchronous Penetration
TSO	Transmission System Operator(s)
UK	United Kingdom
NGUK	National Grid UK
VRE	Variable renewable energy

Notation

$Cost_{start}$	Generator Start up cost
E_k	Kinetic energy at rated speed/nominal frequency
f_0	Frequency
G	Generator output
$GenStart$	Flag indicating if a generator has started
$Gmin$	Minimum stable output of a generator
$Gmax$	Maximum capacity of a generator
H	Inertia constant
Lim_{ROCOF}	ROCOF Limit
NSG	Non-synchronous generation
NI	Net Imports
NE	Net Exports
P_{max}	Largest infeed for a synchronous area
RI_{sys}	System rotational inertia
S_m	Apparent power
SD	System Demand
$SNSP$	System Non-Synchronous Penetration
t_{step}	Time step

Units

GJ	Gigajoule
GW	Gigawatt
GWs	Gigawatt seconds
Hz	Hertz
MVA	Megavolt-ampere
MW	Megawatt
MWs	Megawatt seconds
t	tonne
TWh	Terawatt hour

Managing system frequency in the face of reducing rotational system inertia (i.e. low inertia systems) to avoid such high ROCOF events is considered one of the largest future challenges for power system operators [3,4].

Dynamic studies examining the impact of increased VRE on power system stability examine aspects such as frequency, voltage and angular stability in the immediate aftermath of a system disturbance. The output of an hourly dispatch model provided some of the inputs to the dynamic studies in Ireland (i.e. Republic of Ireland and Northern Ireland) [5] and Great Britain (GB) [6]. Another investigation utilised historical system data following disturbance events to tune the parameters of a dynamic model for the Nordic region [7]. The subsequent model output was compared to newly recorded disturbance events to evaluate its performance. Pagnier et al. investigated the locational aspect of inertia and the impact on fault propagation for Continental Europe [8]. These studies capture the stability effects of particular ROCOF levels or VRE penetration levels but they do not capture the economic and environmental impacts.

The use of a unit commitment and economic dispatch tool provides a complementary way to assess the broader impact of potential strategies to mitigate inertia decline as VRE penetration increases over a longer timeframe. Some studies have considered a constraint to ensure that at all times a certain percentage of generation is synchronous generation to address inertia concerns [9,10]. This type of constraint does not take into account the number and type of generation units required to be synchronised to provide inertia and therefore does not necessarily ensure frequency stability. Daly et al. adopt a more robust approach to determine the costs and impacts of maintaining minimum inertia levels on the Irish power system by determining the amount of rotational inertia required to limit ROCOF to a particular level [11]. By focusing only on Ireland, this work does not capture the impacts of neighbouring systems on each other. This may be significant when one considers the correlation between Ireland and GB's wind power production [12]. Similarly, Johnson et al. used a minimum inertia constraint to determine the impacts of plant closures with various levels of VRE penetration on the stability of the Electric Reliability Council of Texas (ERCOT) system [13]. As part of a broader analysis of EU policy, Collins et al. provided a high-level overview of the impact of inertia constraints at synchronous area level in Europe for one decarbonisation scenario and a single ROCOF level of 0.75 Hz/s [14]. Unlike this work, understanding the impacts of maintaining a minimum inertia level to limit ROCOF to a particular level was not the sole focus of that work and the depth of analysis reflects this.

This study adds to the literature by providing a detailed comparison of two different levels of ROCOF (0.5 Hz/s and 1 Hz/s) for a pair of contrasting decarbonisation scenarios. By considering Europe and each synchronous area in Europe, this work captures the effect neighbouring synchronous areas have on each other when the minimum inertia constraints are applied. Using a unit commitment and economic dispatch model, with constraints to limit ROCOF for prescribed contingency events, the impact on interchange, curtailment of VRE, carbon dioxide (CO2) emissions and production costs in each synchronous area and across Europe are assessed. The scenarios considered, based on the European Network of Transmission System Operators of Electricity's (ENTSO-E) official projections for long-term transmission capacity expansion in Europe, make this work representative of the range of challenges that will be encountered on the continent. The work also explored the distribution of inertia in the large synchronous area of Continental Europe (CE) revealing that some countries will experience periods of no or very low inertia if regional mitigation strategies are not employed.

This paper is organised in five sections. In section 2, the context and the progress made to date in addressing the inertia challenge is reviewed/summarised for Europe. In section 3, the methodology adopted and assumptions used for carrying out the studies are described. In section 4, the results are presented and analysed, followed by conclusions and future work in sections 5 and 6.

2. Context and progress to date

This section provides an overview of how inertia is currently being estimated/measured by ENTSOE members, the factors that can influence the level of inertia on a power system, possible solutions to the inertia challenge and the legislative efforts in Europe to address inertia concerns.

2.1. Inertia and how it is estimated currently

The stored kinetic energy in a synchronous machine's rotating mass provides inertia, which resists changes in the speed of the machine. The inertia constant of a synchronous machine$H$, measured in seconds, is given by the following equation:

$$H=\frac{E_{k,m}}{S_m} \qquad \text{Equation (1)}$$

where $E_{k,m}$ is the kinetic energy of the machine at rated speed in MWs (megawatt seconds) and S_m is the generator rated power in MVA [15]. A power system can be considered to act similar to a giant synchronous machine where the inertia resists changes in frequency of the power system. Similar to equation (1) the system inertia constantH_{sys}, is then the stored kinetic energy in the system divided by the apparent power in the system,S_{sys}. The stored kinetic energy in the system can be approximated as the sum of the stored kinetic energy provided by each synchronous generator online in that system [3]. Using equation (1) the inertia constant of the system, measured in seconds (s), can be calculated as follows:

$$H_{sys}=\frac{E_{k,sys}}{S_{sys}}=\frac{\sum_{i=1}^{N}E_{k,mi}}{S_{sys}}=\frac{\sum_{i=1}^{N}H_iS_{mi}}{S_{sys}} \qquad \text{Equation (2)}$$

For the purpose of this paper, it is appropriate to represent the inertia of a power system in megawatt seconds (i.e. the stored kinetic energy of the system) rather than seconds as per equation (2). For the rest of this paper when the term inertia is used it can be assumed that it refers to the meaning as per equation (3) measured in megawatt seconds.

$$E_{k,sys}=H_{sys}S_{sys}=\sum_{i=1}^{N}H_iS_{mi} \qquad \text{Equation (3)}$$

The standard approach to estimating the inertia of a power system in real time has been to aggregate the inertia provided by each online synchronous machine. A list of some typical values are shown in Table 4 [16]. This is the approach taken by Transmission System Operators (TSO) in Ireland, Denmark, Finland, GB, Norway and Sweden. Some types of electrical load such as synchronous motors can also provide inertia. Generally, the inertial contribution from electrical load is ignored as system operators may not have telemetry on that load and it is normally relatively small [7].

Following a successful trial in 2017 in the United Kingdom (UK), National Grid UK (NGUK) is moving towards direct inertia measurement. This involves creating a miniscule frequency variation of 0.0005Hz, which is measured at various locations around the grid, and the results analysed in a cloud-based analytics server [17]. Other TSO may adopt a similar approach in time, as the estimation method based only on large synchronous generators becomes less relevant. With increasing levels of distributed generation, particularly behind the meter, or embedded in distribution systems, it is becoming increasingly difficult to fully assess which generators besides the large synchronous generators are contributing to system inertia [7]. This is likely to become even more challenging as consumers and prosumers assume a more active role within the electricity market [18].

2.2. Factors that can affect inertia

Generation mix and interconnection to other synchronous systems can all affect the inertia available within a synchronous system. A high percentage of renewable energy in the balancing mix does not automatically result in an inertia issue. This is evident in the Nordic synchronous area where a large amount of renewable energy is provided by hydro-generation. However, a high percentage of VRE can result in reducing inertia, as is the case on the island of Ireland. Interconnection to other jurisdictions also influences the inertia level. Imports via high voltage direct current (HVDC) interconnection can replace generation from synchronous machines, while exports can sometimes allow headroom for additional synchronous generation. To account for this an operational metric is utilised by the TSO in the Ireland synchronous area, which includes the Republic of Ireland and Northern Ireland, known as System Non-Synchronous Penetration (SNSP) [19].

$$SNSP=\frac{NSG+NI}{SD+NE}\times 100\% \qquad \text{Equation (4)}$$

where NSG is non-synchronous generation in MW, NI is net imports in MW, SD is system demand in MW, and $NE$is net exports in MW.

Ireland, out of necessity, has been leading the way for Europe in identifying solutions to integrate higher levels of non-synchronous generation. This SNSP metric is used to identify the amount of non-synchronous generation that can be permitted on the system at any one time while ensuring system stability. Following a successful trial period, the permitted SNSP in Ireland is currently 65% [20] making it the "*first in the world to reach this level*" [21]. There are plans to increase this by 5% each year to a maximum of 75% by 2020 [22]. Monitoring this metric alone is not sufficient to maintain stability so a minimum inertia requirement of 23,000 MW at all times is also in force in Ireland [20].

2.3. Solutions to the inertia challenge

In the *'System Needs Analysis'* for the future European power system, ENTSOE highlights a number of areas that need further research that could mitigate the frequency management challenges as renewable penetration increases. It includes constraining generation from VRE to allow generation providing rotational inertia into the balancing mix, the limitation of cross border flows between small and large synchronous areas for dynamic reasons and using synchronous compensators, as well as grid forming converters and fast frequency response (FFR) amongst other solutions [4].

Provision of FFR from different technology types is discussed in depth by Karbouj et al. [23]. Fast frequency response and synthetic inertia are often conflated. While there is no consensus in the literature on the definition of synthetic inertia, a distinction between synthetic inertial response and FFR is made by Eriksson et al. [24] who also presents a strict definition of synthetic inertial response. Synthetic inertial response means a response that emulates synchronous inertia by responding in proportion to ROCOF and FFR is any other type of fast controlled response [24]. Technologies that have the capability to provide a synthetic inertial response as per Eriksson et al.'s definition are being developed but they have yet to reach maturity. Concerns remain regarding their ability to respond in the required timeframe after detecting a frequency event [25], although the recently concluded RESERVE project demonstrates that this is an active area of research [26–28]. This project also serves to highlight that with the growing amount of distributed generation inertia and control solutions may be provided at distribution level rather than transmission level, which has been the traditional approach.

Some TSO are examining and implementing alternative methods of minimising frequency disturbances. Common methods under investigation include energy storage, modifying system equipment and grid codes to tolerate higher ROCOF levels and incentivising more flexible operation of synchronous machines using ancillary services [25]. EirGrid, the TSO in Ireland, has introduced a new range of ancillary services that complement system rotational inertia to limit ROCOF to facilitate the high level of SNSP [29]. In GB energy storage has been introduced [30]. In Denmark, additional system rotational inertia is achieved by utilising synchronous condensers. These provide additional benefits in terms of reactive support and short circuit currents during faults. Furthermore, TSO are actively participating in research and trials through projects such as DINOSAURS [31], MIGRATE [32] and EU-SysFlex [33] to find workable solutions.

2.4. Forthcoming european legislation on inertia

The legislative package 'Clean Energy for all Europeans', also known as the 'Winter Package', provides for consumer and communities to be active participants that can buy from and sell to electricity markets [34]. It also introduces changes for TSO and how they interact and co-operate with each other on a range of issues including inertia. Members of ENTSO-E have prepared for these changes through amendments to network codes. Article 39 of the 'Network Code on System Operation' (NCSO) requires TSO to participate in a study of their relevant synchronous area(s) to determine if a minimum inertia level or an alternative should be prescribed. If a minimum inertia level is required, the relevant TSO must jointly agree a methodology for defining the minimum inertia level for that area, and each TSO is then responsible for maintaining the required proportion of that minimum inertia level within its area of control [35].

Table 1 below shows which synchronous areas in Europe require minimum inertia levels currently as indicated by their representatives to ENTSOE [36,37]. It should be noted that the assessment of the Baltic States (i.e. Estonia, Latvia and Lithuania) was based on the present strong interconnection with the Integrated/Unified Power System (IPS/UPS) of Russia and Belarus. There are plans by the European Commission (EC) to remove the energy isolation of the Baltic States from the Belarus, Russia, Estonia, Latvia and Lithuania (i.e. BRELL) ring and integrate the Baltic States to the CE synchronous area both in terms of technical standards and market frameworks [38].

Table 1
Status of Minimum Inertia Level Requirement at present.

Synchronous Area	Minimum Inertia Requirement?
Baltic	No
CE	No
GB	No – constraint to reduce largest loss is used
Ireland	Yes
Nordic	No

3. Methodology

The methodology used in this study implemented minimum inertia constraints in Europe in order to explore the impact on total generation costs, VRE curtailment and CO_2 emissions. It is described in this section. This is one proven solution to address reducing inertia as VRE penetration increases that is readily implementable. The approach adopted in this study was to utilise a unit commitment and economic dispatch, set up for contrasting decarbonisation scenarios for the year 2030. The same method for estimating total system rotational inertia in real time operation in most power systems is used. The total system inertia is assumed to be the sum of rotational inertia available from each online synchronous generator. Static constraints to maintain the system rotational inertia for a synchronous area above the amounts required to ensure ROCOF is limited, as defined in Daly et al. [11], are then applied and the outcomes are then examined:

$$RI_{sys} \geq \frac{f_0 \ X \ P_{max}}{2 \ X \ Lim_{ROCOF}} \qquad \text{Equation (5)}$$

where RI_{sys} is the system rotational inertia, f_0 is the nominal system frequency P_{max} is the largest infeed and Lim_{ROCOF} is the ROCOF limit set for the synchronous area.

3.1. Pan european model

A pan-European electricity dispatch test system with hourly resolution developed in an Integrated Energy Model (IEM) for previous works [14,39] in PLEXOS ® Simulation Software [40] has provided the basis for this study. Each Member State is modelled as a node with transmission capacity between countries modified to the ENTSO-E's Reference Capacities for 2030 [41] similar to some of the other studies [14,39]. The objective function is set to minimize the overall generation cost across the EU to meet demand, subject to operational and technical characteristics, while co-optimising thermal and renewable generation. The objective function considers operational costs in the form of fuel costs, carbon costs, and fixed unit start-up costs; the model equations can be found in Refs. [39]. The optimization problem, in the form of a mixed integer linear programme (MILP), is solved for each hour of a 24-h rolling horizon with a 6-h look ahead for the year studied. An overview of the objective function with the main constraint under focus in this study is provided in Table 2.

3.2. Base case scenarios

The two base case scenarios considered in this study are informed by the ENTSO-E Visions for 2030 used to inform the '*ENTSO-E Ten-Year Network Development Plan*', which represent a wide range of energy system decarbonisation with varying levels of electrification heating and transport sectors, and demand response [41]. The IEM model inputs of hourly electricity demand, installed generation capacity mix, and fuel and CO2 pricing in 2030 used to inform the two base case scenarios, Scenario 1 and 2, are taken from the ENTSO-E decarbonisation visions an overview of which is provided in Table 3.

As illustrated in Fig. 1 Vision 1 '*Slowest Progress*' and Vision 4 '*European Green Revolution*' contrast in terms of decarbonisation ambition [41]. In Scenario 1, nuclear still features strongly in many countries while in Scenario 2 nuclear capacity reduces in most countries with the exception of GB.

Table 2
Overview of main objective function and optimization software.

Main Objective Function	Minimize $\sum_{i,t}^{N,T} G_{i,t} \times SRMC_{i,t} \times t_{step} + Cost_{start,i} \times GenStart_{i,t}$ Subject to $Gmin_i \leq G_{i,t} \leq Gmax_i$, $\sum_{i}^{N} G_{i,t} = SD_t$ where $G_{i,t}$ is the power output, $SRMC_{i,t}$ is the Short Run Marginal Cost, $Cost_{start,i}$ is the start-up cost of generator i, $GenStart_{i,t}$ is a flag indicating generator i has started up, $Gmin_i$ is the minimum generation level, $Gmax_i$ is the maximum capacity of the generator, SD_t is the total system demand at time t.
Constraint under focus	$\sum_{i=1}^{N} H_i S_{mi} \geq RI_{sys}$ for each synchronous area (Eq. (3) and Eq. (5))
Time step	1 h
Horizon	24 h + 6 h look ahead
Software Version	PLEXOS 7.500 R05
Solver	Xpress-MP[a]
CPU Type	Intel(R) Core(TM) i5-6300U CPU @ 2.40 GHz

[a] The academic licence for the Xpress-MP solver was kindly provided by Fair Isaac Corporation (FICO).

Table 3
Comparison of ENTSOE visions.

Scenario	1	2
Basis	**ENTSOE Vision 1**	**ENTSOE Vision 4**
Electricity Demand (TWh)	3434	3616
Variable Renewable Capacity (GW)	388	614
Fuel Prices (€/GJ):	9.5	7.2
Natural Gas	17.3	13.3
Oil	3.0	2.2
Coal		
CO_2 Prices (€/Tonne)	17	76
Merit Order	Coal before gas	Gas before coal

3.3. Renewable generation profiles

The VRE implemented in the IEM in the context of this work are wind and solar photovoltaic (PV) generation only. The synthesised hourly output from each Member States wind and solar PV generation portfolio derived from the EMHIRES dataset [42] for the year 1989 was chosen. This was found to be the best representative year for the long run average of European wind and solar profiles [43]. Historic hydro generation profiles with a monthly resolution for the year 2012 provided by ENTSO-E for each individual member state of the EU-28, Switzerland and Norway were scaled appropriately for this study.

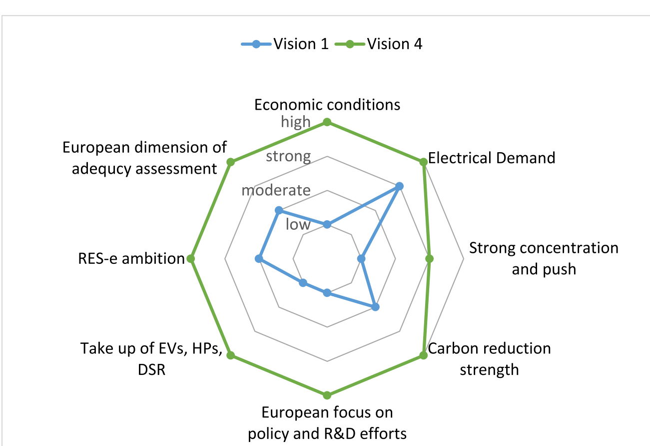

Fig. 1. Overview of the characteristics of the relevant two ENTSO-E Visions as interpreted from [41].

3.4. Generator characteristics

The main generator characteristics used are detailed in Table 4, which are based on standard generator characteristics used in previous studies [14,39]. Each generator type was assigned a particular value for its stored rotational energy (MWs) [16].

For the purpose of this study, the contribution to inertia from wind turbines is considered to be zero.

3.5. Model runs

Three modelling run iterations were undertaken for each base case with different levels of constraints. Firstly, no minimum inertia constraints were applied. The purpose of this run, which effectively ignores the stability issues associated with low inertia systems, was to identify which synchronous areas would require constraints to limit ROCOF. In the second and third runs, constraints are applied to limit ROCOF to 0.5 Hz/s and 1 Hz/s respectively for the loss of the largest infeed for the relevant synchronous grids in Europe as identified by the first run. The synchronous grids in Europe considered were Ireland, GB (England, Scotland and Wales), the Baltic states (i.e. Estonia, Latvia and Lithuania), the Nordic states (i.e. Finland, Norway, and Sweden) and the CE grid (i.e. Austrian, Belgium, Bulgaria, Croatia, Czech Republic, Denmark, France, Germany, Greece, Hungary, Italy, Luxembourg, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, and Spain). For most synchronous areas, the largest infeed is considered to be the maximum capacity of the largest generator or cross border interconnector. The exception to this is CE, where the largest loss is based on the ENTSO-E definition of the 'Reference Incident' of 3000 MW representing the loss of the two largest nuclear power units within the same power station that can cascade trip for a frequency disturbance [44]. The minimum static levels of inertia required to mitigate the loss of the largest infeed for the two ROCOF levels, calculated as per Equation (1), are provided in Table 5.

As can be seen in Table 5 a ROCOF tolerance of 1 Hz/s halves the required level of system inertia to offset the largest infeed compared to a ROCOF tolerance of 0.5 Hz/s. The selection of 0.5 Hz/s and 1 Hz/s was influenced by the situation in the synchronous grid in Ireland. The current ROCOF level for the Republic of Ireland is 0.5H/z. However, the TSO, EirGrid, had planned for the ROCOF level to be increased to 1 Hz/s by late 2017 [22], but this is not implemented yet [20].

3.6. Assumptions made in the analysis

This study is not intended to replace dynamic studies, rather this

Table 4
Main generator characteristics.

Fuel Type	Capacity (MW)	Start Cost (€/Start)	Minimum Stable Factor[a] (%)	Stored Rotational Energy (MWs)
Biomass-waste fired	300	10,000	30	1220
Biogas fired	150	12,000	40	610
Geothermal	70	3000	40	0
Hydropower, lakes	150	0	10	700
Hydropower, run of river	200	0	10	820
Natural gas CCGT	450	80,000	40	3200
Natural gas OCGT	100	10,000	20	240
Nuclear energy	1200	120,000	50	5800
Oil fired	400	75,000	40	900
Solids fired	300	80,000	30	1600

[a] Minimum stable factor is the minimum stable generation level defined as a percentage of Max Capacity.

Table 5
Largest Infeed and assigned minimum inertia levels.

	Largest Infeed (MW)	Assigned minimum inertia for ROCOF limit of 1 Hz/s (MWs)	Assigned minimum inertia for ROCOF limit of 0.5 Hz/s (MWs)
CE	3000	75,000	150,000
Nordic	1400	35,000	70,000
GB	2000	50,000	100,000
Baltic	700	17,500	35,000
Ireland	700	17,500	35,000

work is intended to complement and provide insights into the impacts of applying inertia constraints over a longer time horizon. Other issues that will arise from a lack of synchronous machines and a proliferation of inverter connected generation such as reactive support, short circuit currents, harmonics or blackstart capability are not considered. A perfect day-ahead market is assumed across the EU (i.e. no market power or anti-competitive bidding behaviour, thus power stations bid their short-run marginal cost (SRMC)) similar to Deane et al. [45]. The results then reflect the least cost generation dispatch based on marginal cost (MC) rather than the cost resulting from bidding behaviour. Standard generator classes with standard characteristics such as maximum capacities, minimum stable factors, startup costs and the inertia contribution for each generator type are considered. This eliminates the need to obtain detailed technical data for each generator within the countries studied.

In this study, the power systems of Malta and Cyprus were excluded as the inertia constraints considered in this study would be overly onerous on such small systems. It was assumed that the power system of the Baltic States consists only of Latvia, Lithuania and Estonia for this study. This reflects the ambition to reduce dependence on the AC interconnectors to the Russian and Belarusian power systems by 2025. Interconnection between countries is included but no transmission network within a country is considered to keep simulation times reasonable. Hence, Denmark is considered to be wholly part of the CE synchronous area whereas in reality part of the Danish power system is within the Nordic synchronous area. Inertia from non-generating sources such as synchronous condensers has not been included as the focus was to ascertain how much inertia would be provided by conventional generation sources in the year 2030 in the absence of any shift in portfolios. Inertia provided by electrical load is ignored as it is normally relatively small.

3.6.1. Limitations

The scope of the study is limited to inertia from conventional generation sources only and thus the potential to provide synthetic inertia and fast frequency response is not included. Therefore, the results reflect a worst-case scenario in terms of inertia provision, albeit somewhat alleviated by the perfect foresight of the IEM model in PLEXOS. The results of this study, particularly in relation to VRE curtailment, are likely to be conservative, as effects caused by congestion due to bottlenecks in transmission systems within countries are not captured and the IEM resolution time may also have an affect. The study considers a static limit only for the minimum inertia requirement in each synchronous area. Daly et al. showed that applying a dynamic inertia requirement for the island of Ireland reduced costs compared to a static inertia requirement [11]. Furthermore, the provision of ancillary services that may reduce minimum inertia requirements has not been considered in the study.

4. Results & analyses

The scenarios offer divergent decarbonisation ambitions for the European power system and differ in a number of areas including levels of electricity demand, VRE generation capacity and fuel prices. The purpose of the analyses of the results is not to compare these base case scenarios to each other but rather to compare the effect of applying various minimum inertia constraints to each base case. The model is set up to optimise cost rather than VRE curtailment and CO_2 emissions. The CO_2 emissions are captured to some extent within the optimization problem, as the CO_2 price is included in the calculation of total generation costs.

4.1. Simulations without an inertia constraint applied

In Fig. 2, the inertia duration curves for each synchronous area in Europe for the unconstrained simulations for each base case scenario are presented. The reference lines show the minimum levels required to minimize ROCOF to 0.5 Hz/s and 1 Hz/s as per Table 5. The curves for the Nordic, CE and GB synchronous areas appear to be quite smooth compared to the curves for the Baltic and Ireland/Northern Ireland systems, but this is simply due to the scaling of the y-axis.

The model uses perfect foresight and focuses on minimising

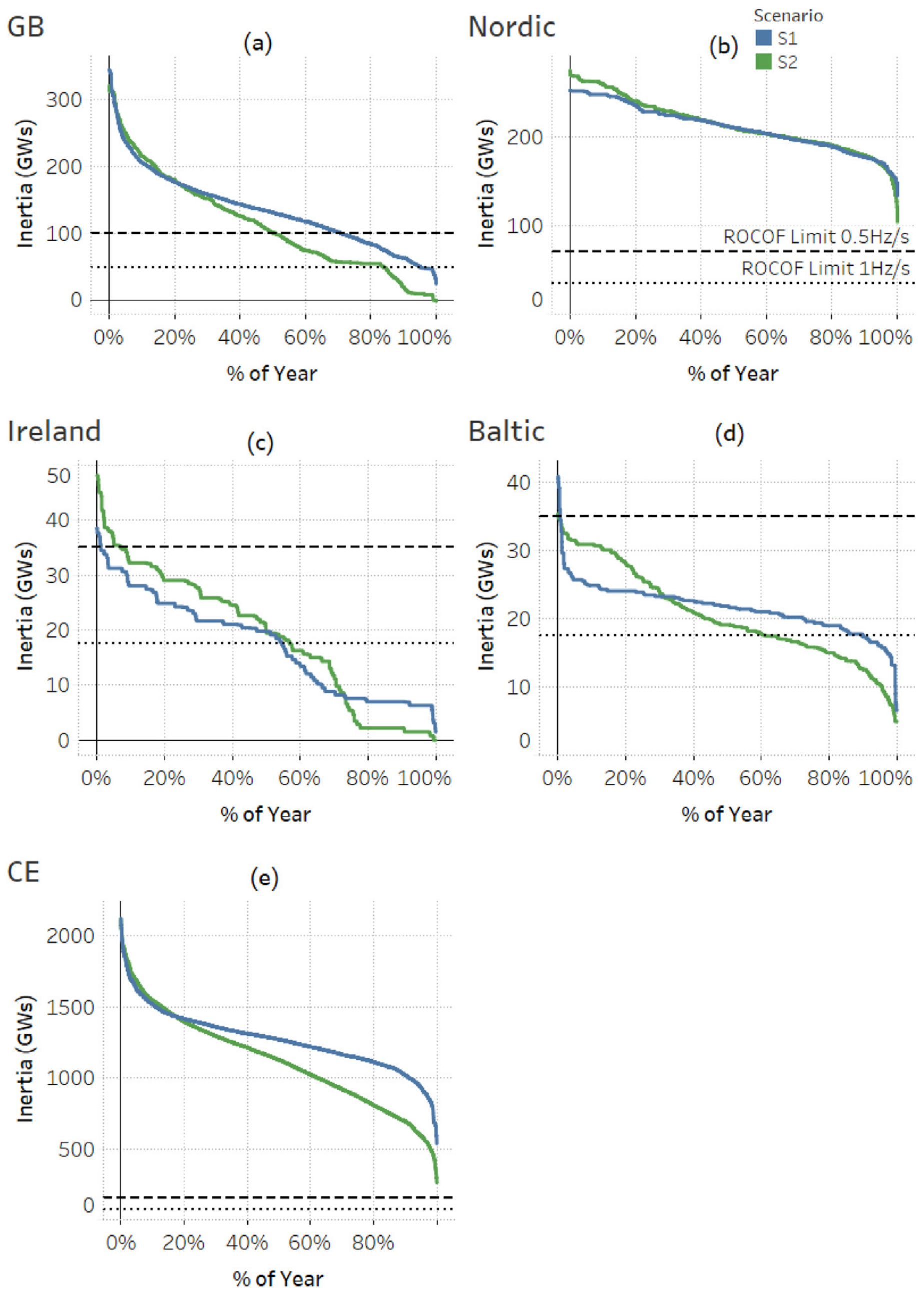

Fig. 2. Inertia duration curves for all synchronous grids with no ROCOF limit.

total generation costs across Europe as a whole. Therefore, the dispatch will change with the constraints applied. While only indicative as the optimization of constraints will result in a less severe outcome, it is clear from Fig. 2 (a)–(e) that the constraint is likely to have a significant effect on the Baltic states and Ireland synchronous areas and to a lesser extent on the synchronous area of GB. It also shows that the constraints will not be binding for the Nordic region and CE synchronous areas in either scenario. Examining the hourly contribution of kinetic energy from each generation type for the CE and Nordic systems for the base case scenarios provides more insights as shown in Fig. 3 (a) and (b). It is evident that in the Nordic synchronous area hydro generation alone is sufficient to meet the minimum inertia requirement for both Scenario 1 and Scenario 2. Due to the sheer size of the synchronous area and the volume and mix of generators required to meet the system demand, the CE synchronous area also easily surpasses the limits set out in Table 5.

Due to these findings, the inertia constraints were applied to the Baltic states, GB and Ireland synchronous areas for subsequent model runs. After each simulation, the hourly stored kinetic energy for the CE and Nordic region was checked to ensure it did not breach the requirements in Table 5 due to the change in dispatch to meet the constraints in the other synchronous areas.

4.2. Simulations with inertia constraints to limit ROCOF

The changes in interchange between synchronous areas, total generation costs, VRE curtailment and CO2 emissions relative to the base case that result from applying the constraints are presented in Table 6 and Fig. 4 for Scenario 1 and Table 7 and Fig. 5 for Scenario 2.

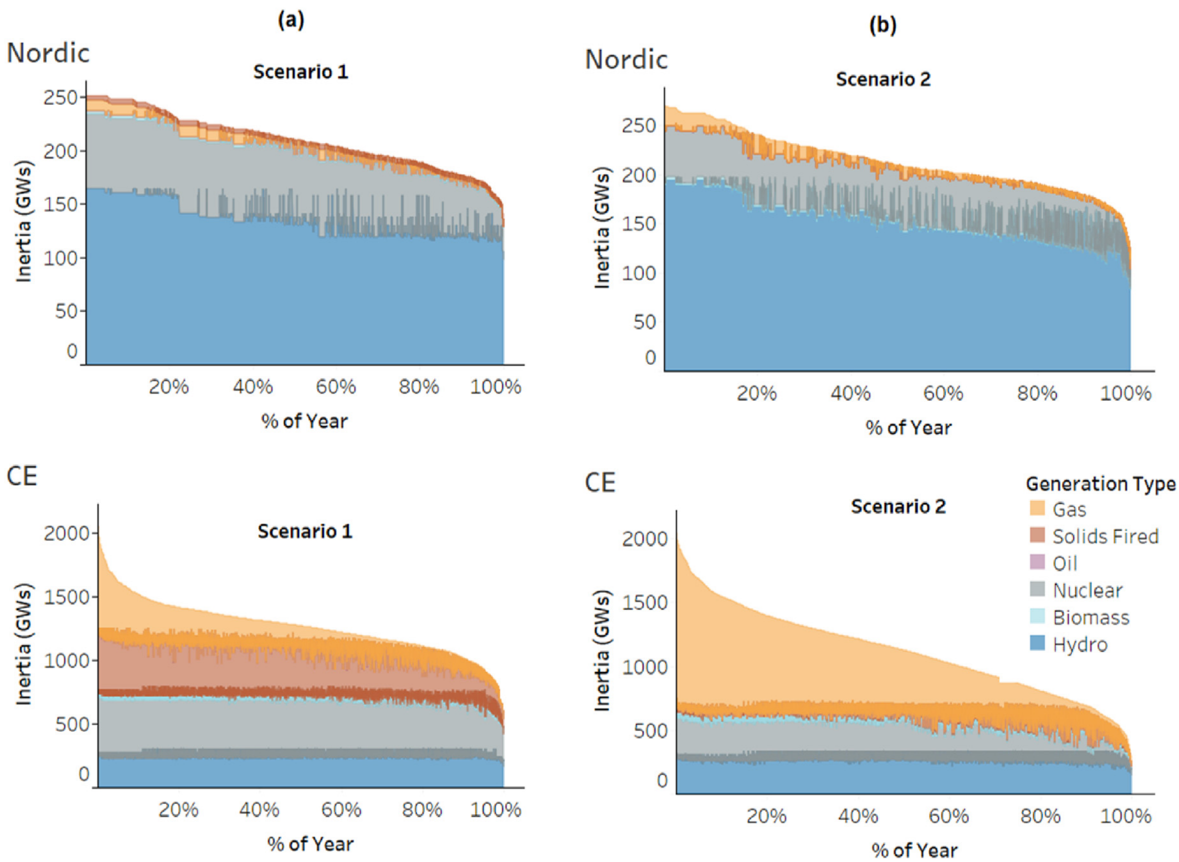

Fig. 3. Inertia Contribution by Generation type for the Nordic and CE synchronous areas for (a) Scenario 1 and (b) Scenario 2 with no ROCOF Limit.

Table 6
Change relative to base case for Scenario 1.

ROCOF Constraint	Total generation cost		VRE Curtailment		CO2 Emissions	
	1 Hz/s	0.5 Hz/s	1 Hz/s	0.5 Hz/s	1 Hz/s	0.5 Hz/s
Baltic	−0.5%	53.1%	0%	0.1%	−0.3%	48.9%
CE	0%	−0.5%	0.1%	0.1%	0%	−0.7%
GB	−0.6%	−2.6%	0%	0%	−0.4%	−1.1%
Ireland	9.7%	43.4%	0.2%	2.15%	4.3%	20.2%
Nordic	−0.6%	−1.9%	0%	0.02%	−1.2%	−5.6%
Total	0.04%	0.07%	0.01%	0.05%	−0.04%	−0.41%

Table 7
Percentage change relative to base case in Scenario 2.

ROCOF Constraint	Total Generation cost		VRE Curtailment		CO2 Emissions	
	1 Hz/s	0.5 Hz/s	1 Hz/s	0.5 Hz/s	1 Hz/s	0.5 Hz/s
Baltic	0.2%	14.7%	0%	0%	0.1%	10.9%
CE	−0.1%	−1.1%	0%	0.04%	−0.2%	−1.1%
GB	1.3%	7.4%	0.5%	1.5%	1.6%	8.6%
Ireland	10.8%	37.5%	1.3%	5.9%	11.1%	28%
Nordic	0.0%	−8.0%	0.1%	0.2%	−0.1%	−15.1%
Total	0.3%	0.8%	0.1%	0.4%	0.3%	0.9%

The results confirm that for the heavily decarbonised Scenario 2, the total generation costs, VRE curtailment and CO_2 emissions increase with increasing inertia constraint for the pan European power system. For a less ambitious scenario, Scenario 1, the results follow the trend for rising total generation costs and VRE curtailment, but a decreasing trend in emissions is observed. In this

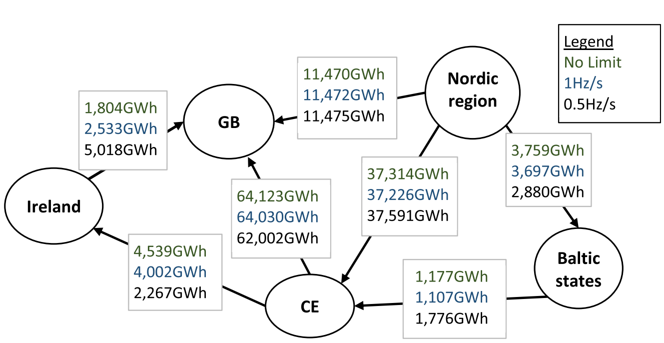

Fig. 4. Net interchange between synchronous areas for each ROCOF level in Scenario 1.

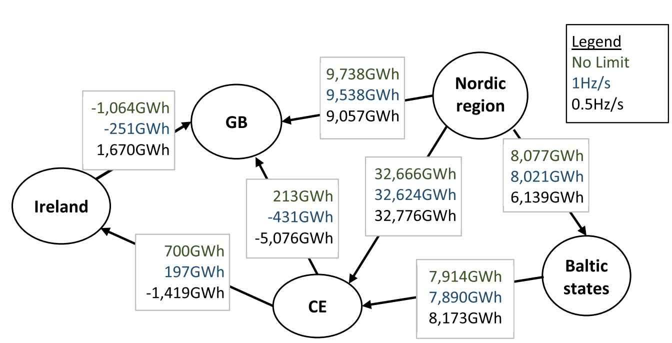

Fig. 5. Net interchange between synchronous areas for each ROCOF level in Scenario 2.

scenario, coal is cheaper than gas but a Combined Cycle Gas Turbine (CCGT) contributes twice as much rotational kinetic energy as a solid fuel fired generator (Table 4). The generation output from coal reduces to allow additional gas fired generation units synchronize for inertia provision to meet the constraint. Gas produces less CO_2 emissions than coal and thus a decrease, albeit small, in CO_2 emissions for this constraint is noted. This shows that minimum inertia constraints are a useful tool to have as the transition to higher penetrations of VREs and power electronic devices accelerates. There will come a point in the transition, however, where the inertia constraints impinge on progress towards a low carbon environment. Thus, better synthetic inertia technologies and the communications systems will support a quicker transition to a low carbon power system.

Across Scenario 1 and 2, the trends for the CE and Nordic region are consistent; total generation costs and CO2 emissions reduce with the increasing inertia constraint. In the synchronous areas where the constraint is heavily binding, the constraint causes an increase in generation. Thus, the export required from the CE and Nordic region reduces and generation in the CE and Nordic region reduces. The generation reductions affects fossil fuel fired generation plant and results in reductions in CO_2 emissions in these areas. Curtailment in these areas also increases with the increasing inertia constraint as less power is exported so there is less headroom for VRE generation.

For Ireland, additional hydro and gas generation units mainly provide the additional inertia required to meet the minimum inertia constraint (Fig. 6).

The suggestions of EirGrid [46] and Cuffe et al. [47] hold true for Ireland in this study as total generation costs, VRE curtailment and CO2 emissions increase with increasing minimum inertia constraint in both scenarios. The doubling of minimum inertia constraint results in the total generation costs increasing from 9.7% to 43.4% for Scenario 1 and from 10.8% to 37.5% for Scenario 2, while CO2 emissions increase from 4.3% to 20.2% and from 11.1% to 28.1% for Scenario 1 and 2 respectively.

Due to the interconnected nature of the power systems within Europe, constraints in one synchronous area can affect others. In this work, GB benefits from the heavily binding constraints in Ireland due to the increased exports. Total generation costs, VRE curtailment and CO2 emissions increase in GB also but only for Scenario 2 the more heavily decarbonised scenario (Table 7). Even though the constraint is binding at times in the GB synchronous area in Scenario 1, the total generation costs decrease by 2.6% for the more severe constraint compared to the base case. The constraint in GB does not bind as often as it does in Ireland, GB's neighbour. It results in Ireland generating more electricity to meet this constraint and becoming a net exporter for the most severe constraint examined. The exports to GB from Ireland more than double and GB benefits from this. As shown in Fig. 4, there is a net increase in imports to GB. In fact, the yearly total generation in GB reduces thereby reducing the total generation costs and CO_2 emissions. This is due to reduced production from gas and solids fired generation. However, with Brexit and increased HVDC

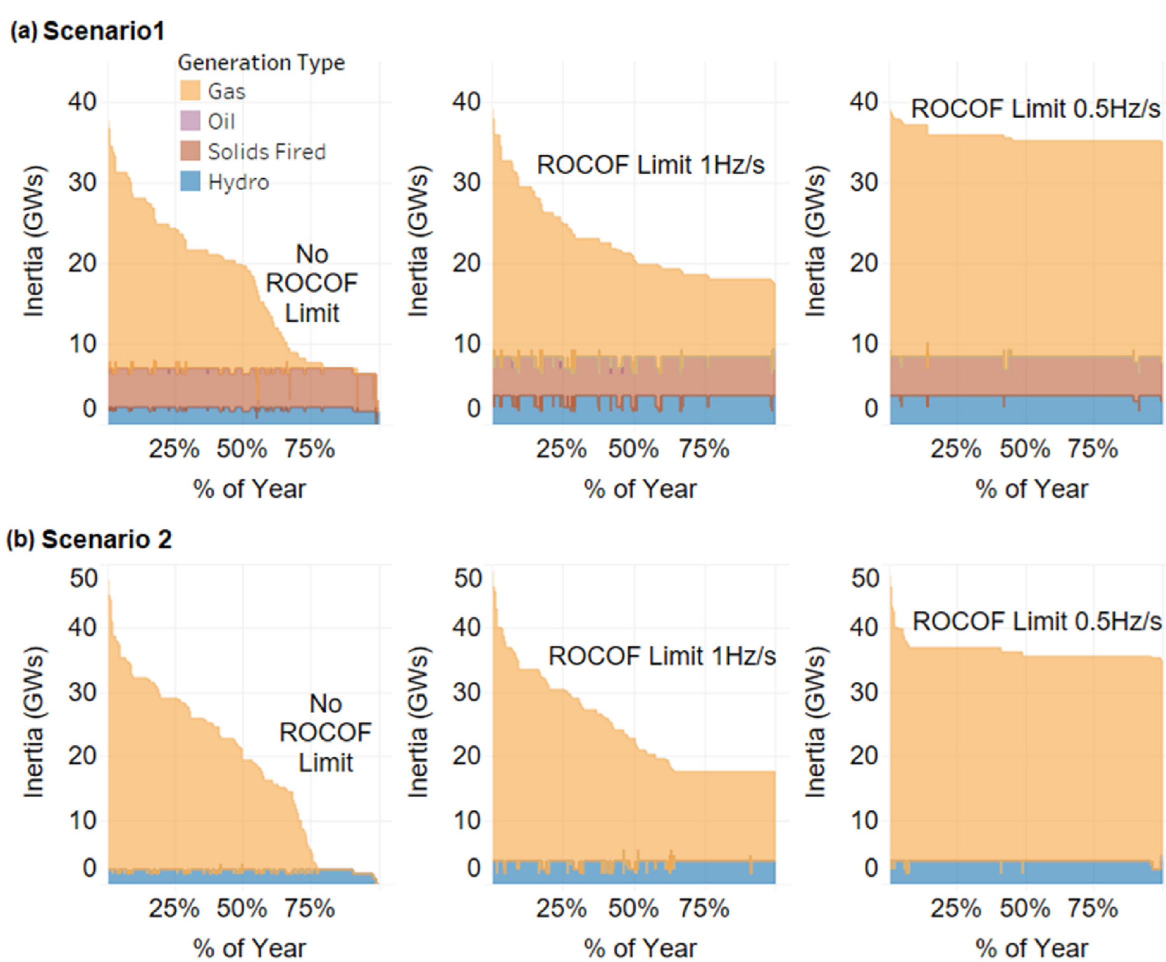

Fig. 6. Hourly Inertia contribution by generation types for Ireland for (a) Scenario 1 and (b) Scenario 2 ranked by total inertia as a percentage of year.

interconnection between France and Ireland, this may change, leaving GB more isolated and at risk. This is particularly relevant to GB in terms of future generation expansion planning and grid code modifications.

Earlier the analyses showed the availability of large quantities of hydro generation gave the Nordic region a weighty advantage in terms of inertia provision. Similarly, the advantages of generation mix is also observed when the results of the Baltic states are compared to Ireland in Figs. 6 and 7. In the Baltic states, as the constraint increases, additional hydro and gas generation units are synchronised at times to meet the inertia constraint requirement. The Baltic synchronous area has over 5 times the amount of hydro that Ireland has in both scenarios. In Scenario 1, nuclear generation and hydro provide the majority of the required inertia with the rest comprised of biomass and gas fired generation when required. In Scenario 2, nuclear does not form part of the generation mix. This highlights the pivotal role that generation capacity mix plays on the effect a minimum inertia constraint has in a power system.

The practical and grid code limits for ROCOF in the various synchronous areas in Europe vary from 0.25 Hz/s [49] up to 2.5 Hz/s [50]. This study focused on the levels currently set and proposed in Ireland. Increasing the minimum inertia requirement to meet a ROCOF level of 0.5 Hz/s has a considerable effect in Ireland and in the Baltic synchronous area. For example, in the Baltic synchronous area, relaxing the constraint from a 0.5 Hz/s limit to a 1 Hz/s limit would reduce the total generation costs by over 53% for Scenario 1 and 14% for Scenario 2 while CO_2 emissions would reduce by 49% and 11% respectively. The doubling of the inertia constraint had a significant influence in the areas where the constraint was binding in both scenarios. This emphasizes the importance of increasing ROCOF tolerance as much as possible in the path towards achieving cost effective decarbonisation and integration of VRE. Given that this study assumed that the Baltic synchronous area was comprised of Estonia, Latvia and Lithuania only, it emphasizes the importance of undertaking long-term inertia studies for this area. This would help identify if the ROCOF limit currently employed should remain at the same level when it is de-synchronised from the IPS/UPS of Russia and Belarus.

Adopting the same approach to determining the inertia constraint level across each synchronous area in Europe, has resulted in a situation where the constraint is most heavily binding in the smaller synchronous areas. Examining the results from a synchronous area level has revealed that when a constraint is more heavily binding in one synchronous area than its neighbour, it can have a positive outcome for its neighbours. In the next subsection, the results of per-country analyses of the CE synchronous area are presented.

4.3. Inertia distribution in the CE synchronous area

In the two base case scenarios considered, there is sufficient inertia within the CE synchronous area as a whole to limit ROCOF to

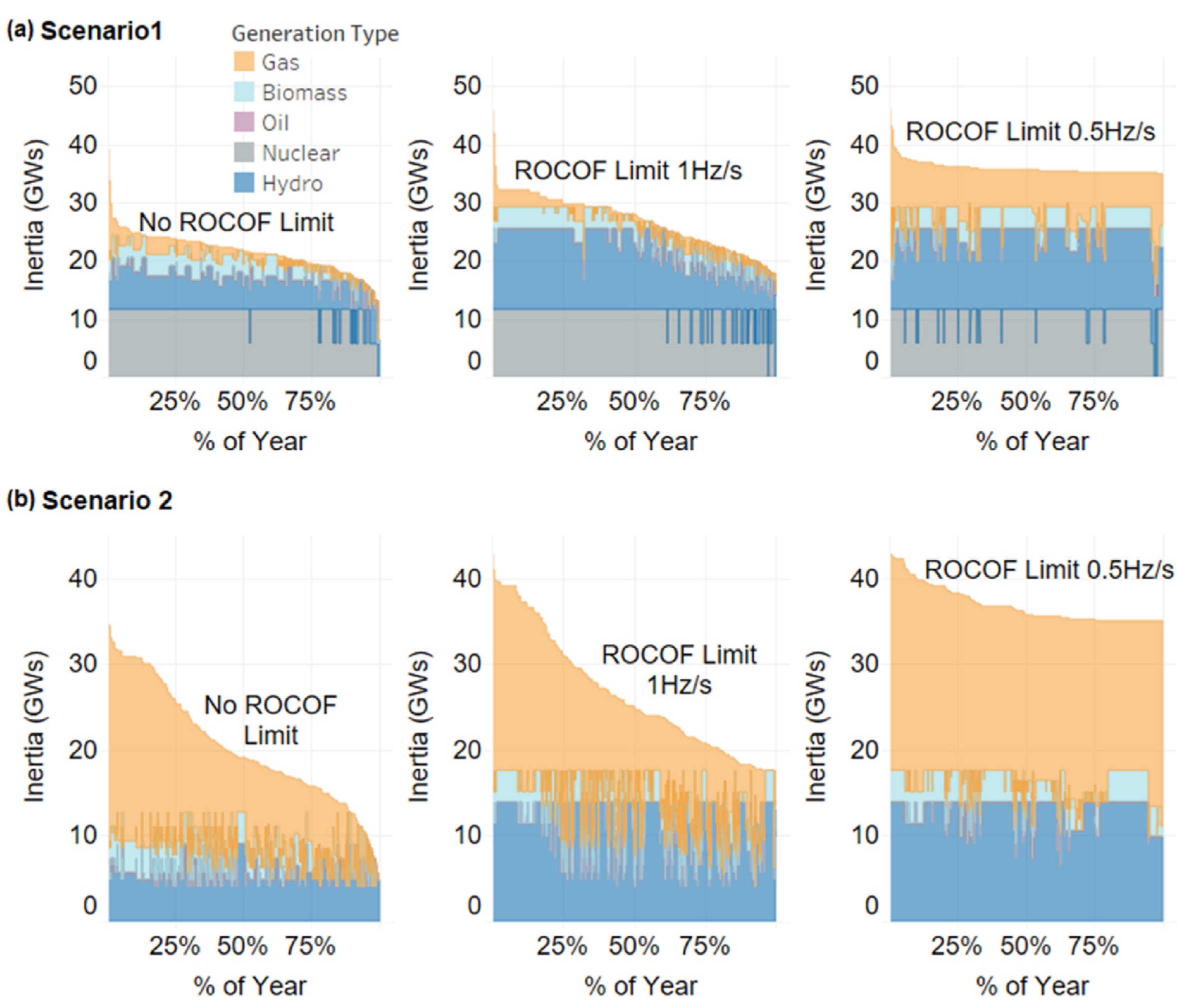

Fig. 7. Hourly Inertia contribution by generation types for Baltic area for (a) Scenario 1 and (b) Scenario 2 ranked by total inertia as a percentage of year.

Table 8
Minimum, maximum and average hourly inertia values in the CE synchronous area.

Base case Scenario	Scenario 1			Scenario 2		
Country	Minimum	Maximum	Average	Minimum	Maximum	Average
Denmark	0	11920	5951	0	35280	3916
Portugal	0	49710	19264	0	50650	23905
Spain	0	263740	114885	0	313180	136519
Germany	0	403600	213412	0	349710	160535
Belgium	2340	64580	26513	0	63880	42795
Luxembourg	2460	6270	2862	2460	6270	4364
Slovenia	2920	17250	13106	3620	22350	16529
Netherlands	5500	110920	45177	700	109960	47080
Bulgaria	6000	42220	34108	3500	28520	23886
Croatia	7640	16500	12648	4100	20700	10074
Czechia	8840	74160	33276	3040	46560	28825
Romania	10280	50780	32279	0	61900	32912
Hungary	12420	31490	26645	0	51290	19876
Slovakia	18840	36010	30737	6420	36620	26175
Switzerland	21000	55860	41760	17500	54170	37845
Greece	21600	57220	28896	0	59600	36247
Austria	27340	48130	37868	17220	88750	46498
Italy	31100	356700	116988	0	322340	114379
Poland	34880	154390	100894	17480	109850	71383
France	150980	365480	331540	22400	356460	234386

1 Hz/s and 0.5 Hz/s for the loss of 3000 MW of generation for the year 2030. Delving into the results on a per-country level (Table 8) reveals that sufficient inertia at synchronous area level does not guarantee that sufficient inertia is maintained at a per-country basis at all times.

Countries such as France, with a large nuclear generation portfolio that features regularly in the balancing mix, have an automatic advantage due to the contribution of stored rotational energy per nuclear generation unit (Table 4). The minimum hourly inertia level in France for all of 2030 in Scenario 1 exceeds the minimum inertia requirement for the entire CE area to limit ROCOF to 0.5 Hz/s. In Scenario 2, which is the more ambitious scenario in terms of the volume of VRE penetration, France also has the highest minimum inertia over the year albeit much lower than in Scenario 1.

As shown in Table 8 the gap between the maximum and minimum in countries such as Spain and Germany is stark. The period when inertia was at its lowest for CE for the entire year was examined to understand how vast the differences in inertia could be between neighbouring countries. Fig. 8 shows the distribution of inertia level by country for Scenario 1 and 2 for the hour where inertia across CE is at its lowest. The inertia from France alone in this period in Scenario 1 is more than sufficient to provide the inertia required for the CE synchronous area for the most severe constraint to limit ROCOF to 0.5 Hz/s. Germany, Portugal and Spain on the other hand provide no inertia. For the period where inertia is at its lowest across CE in Scenario 2, France is still the largest contributor of inertia, at approximately 52 GWs and Spain, Portugal, Italy, Denmark and Germany provide zero inertia.

An obvious area to focus on based on Fig. 8 is the Iberian Peninsula, which in both scenarios has zero inertia. Although there are plans to increase interconnection to France, the peninsula is still poorly interconnected. Bearing in mind that the major blackout experienced in Europe in 2006 was a result of the system splitting into smaller unbalanced isolated systems [48], system splits are credible contingencies. Without the application of a minimum inertia level on the Iberian Peninsula, such a contingency would have dire consequences. This scrutiny of the CE area revealed that even though the requirement at a synchronous area level was met, localised deficiencies could exist. Examining inertia at a more localised level in large synchronous areas such as CE is essential as the penetration of VRE increases. This demonstrates the limitations of considering a minimum inertia requirement at a synchronous area level as a proxy for system stability without having first conducted a complementary dynamic study of the area. The requirement alone does not consider the physical locations of the inertia providers within the synchronous area and therefore does not ensure frequency stability in the event of a contingency such as a system split.

The inertia providers considered in this piece of work were limited to large synchronous generators and did not capture the inertia from other sources similar to the inertia estimation methods employed by many TSO. Minimum inertia constraints provide a useful transition tool as confirmed by this study, however, to gain the highest benefit in terms of CO2 emissions reductions it is essential that the TSO utilise advanced methods of calculating or measuring real time inertia. Real time inertia monitoring would flag situations where there are inertia deficits. It would also ensure that the contribution to system inertia from all sources is captured thereby reducing the situations where synchronous generation is constrained on for inertia reasons. Furthermore, if the TSO provide transparent plans for funding future ancillary services it may result in the emergence of new inertia providers at a more rapid pace. In addition to inertia [11], explicit payments for ramping [51], balancing [52], primary frequency response [53], fast frequency response [54,55] may be necessary as the needs of the system evolves. EirGrid is the first system operator in Europe to design new ancillary services related to non-synchronous VG integration [56] but it is too early yet to determine how effective it will be.

5. Conclusion

The increase in renewable generation, particularly VRE, presents challenges in power system operation with decreasing levels of synchronous generation. One of the tools available to TSO is to ensure that there is a minimum level of inertia on the system at all times. Using a unit commitment and economic dispatch model for the year 2030, this work explored the impact of applying minimum inertia levels to five synchronous areas in Europe for two diverging decarbonisation scenarios for two ROCOF limits. The analyses found that the impact of minimum inertia levels were unique to each synchronous area depending on size, generation capacity mix, and interchange with neighbouring synchronous areas. This study

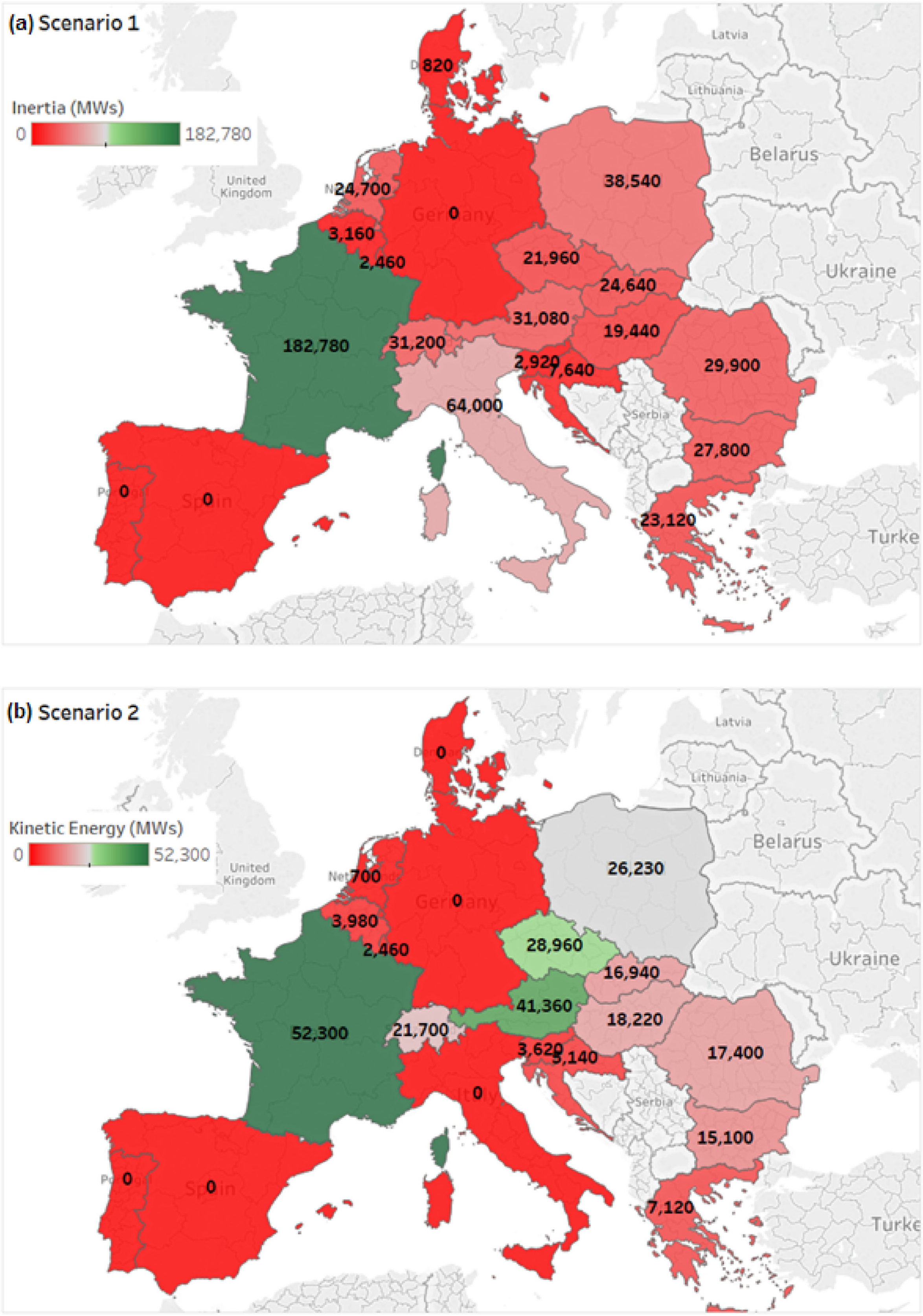

Fig. 8. Contribution per country at lowest hourly inertia across CE for (a) Scenario 1 and (b) Scenario 2.

highlighted the effect of ROCOF limits, the potential consequences of using a minimum inertia requirement at synchronous area level without a complementary dynamic stability study and the importance of TSO adopting real time inertia monitoring. It demonstrated that minimum inertia levels may be useful in the transition to higher penetration levels but will ultimately impede emissions reduction goals if not replaced in a timely manner. Finally, this work also shows the social benefits of coordinated balancing and planning of interconnection across the wider EU in terms of achieving EU emissions reduction and VRE deployment targets.

6. Future work

The model presented in this work could be extended by the inclusion of additional technology types such as concentrated solar power, energy storage and synchronous condensers. An examination of the technologies and associated costs that may enable a shift away from the use of minimum inertia levels to maintain ROCOF below certain values is also recommended. Additionally, the methodology followed in this study could be used to justify the retrospective application of more recent grid code requirements on ROCOF to older generators in Denmark and Spain for example. A fundamental finding of the work was that minimum inertia requirements should be complemented by dynamic stability studies, thus such a study of CE 'soft linked' to the outputs of this study to investigate further is a natural next step of this work.

CRediT (Contributor Role Taxonomy)

Laura Mehigan is a PhD student at University College Cork. This work forms part of a PhD in Energy Engineering investigating the role decentralization and interconnection in the evolution of future electricity systems.

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.

CRediT authorship contribution statement

L. Mehigan: Conceptualization, Investigation, Methodology, Formal analysis, Visualization, Writing - original draft. **Dlzar Al Kez:** Writing - review & editing. **Seán Collins:** Data curation, Writing - review & editing. **Aoife Foley:** Visualization, Writing - review & editing. **Brian Ó'Gallachóir:** Supervision, Funding acquisition. **Paul Deane:** Supervision, Conceptualization, Validation, Visualization, Writing - review & editing, Funding acquisition.

Acknowledgments

This work forms part of the Collaborative REsearch of Decentralization, ElectrificatioN, Communications and Economics (CREDENCE) project, which is funded under the US-Ireland Research and Development Partnership Programme (16/US-C2C/3290) by Science Foundation Ireland (SFI), Ireland, Department for the Economy (DfE) Northern Ireland, National Science Foundation (NSF), United States and (Centre to Centre) award.

References

[1] IEA. World. Energy outlook 2018 - executive summary. International Energy Agency; 2018. p. 4.
[2] A Clean Planet for all A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy. European Commission; 2018. https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52018DC0773&from=EN.
[3] Tielens P, Van Hertem D. The relevance of inertia in power systems. Renew Sustain Energy Rev 2016;55:999–1009. https://doi.org/10.1016/j.rser.2015.11.016.
[4] ENTSOE. European power system 2040 - the ten year development plan 2018 system needs analysis. 2018.
[5] Creighton K, McClure M, Skillen R, O'Higgins J, McCartan T, Rogers A. Increased wind generation in Ireland and northern Ireland and the impact on rate of change of frequency. Procedings of 12th Wind Integration Workshop; 2013. http://www.eirgridprojects.com/site-files/library/EirGrid/Increased%20Wind%20Generation%20in%20Ireland%20and%20Northern%20Ireland%20and%20the%20Impact%20on%20Rate%20of%20Change%20of%20Frequency.pdf.
[6] Urdal H, Ierna R, Zhu J, Ivanov C, Dahresobh A, Rostom D. System strength considerations in a converter dominated power system. IET Renew Power Gener 2015;9(1):10–7. https://doi.org/10.1049/iet-rpg.2014.0199.
[7] ENTSOE. Nordic report on future system inertia. 2015. https://docstore.entsoe.eu/Documents/Publications/SOC/Nordic/Nordic_report_Future_System_Inertia.pdf.
[8] Pagnier L, Jacquod P. Inertia location and slow network modes determine disturbance propagation in large-scale power grids. PloS One 2019;14(3):e0213550. https://doi.org/10.1371/journal.pone.0213550.
[9] Vithayasrichareon P, Riesz J, MacGill I. Operational flexibility of future generation portfolios with high renewables. Appl Energy 2017;206:32–41. https://doi.org/10.1016/j.apenergy.2017.08.164.
[10] Deetjen TA, Martin H, Rhodes JD, Webber ME. Modeling the optimal mix and location of wind and solar with transmission and carbon pricing considerations. Renew Energy 2018;120:35–50. https://doi.org/10.1016/j.renene.2017.12.059.
[11] Daly P, Flynn D, Cunniffe N. Inertia considerations within unit commitment and economic dispatch for systems with high non-synchronous penetrations. IEEE PowerTech, Eindhoven. IEEE, p. 1-6.http://doi.org/10.1109/PTC.2015.7232567.
[12] Malvaldi A, Weiss S, Infield D, Browell J, Leahy P, Foley AM. A spatial and temporal correlation analysis of aggregate wind power in an ideally interconnected Europe. Wind Energy 2017;20(8):1315–29. https://doi.org/10.1002/we.2095.
[13] Johnson SC, Papageorgiou DJ, Mallapragada DS, Deetjen TA, Rhodes JD, Webber ME. Evaluating rotational inertia as a component of grid reliability with high penetrations of variable renewable energy. Energy 2019;180:258–71. https://doi.org/10.1016/j.energy.2019.04.216.
[14] Collins S, Deane JP, Ó Gallachóir B. Adding value to EU energy policy analysis using a multi-model approach with an EU-28 electricity dispatch model. Energy 2017;130:433–47. https://doi.org/10.1016/j.energy.2017.05.010.
[15] Kundur P, Balu Neal J, Lauby Mark G. Power system stability and control. New York: McGraw-Hill; 1994.
[16] Anderson PM, Fouad AA. Power system control and stability. 2ND ED. Wiley India Pvt. Limited; 2008.
[17] Berry B. In: Inertia estimation methologies vs measurement methodology: impact on system operations. CIGRE symposium; 2019. Aalborg, Denmark, http://reactive-technologies.com/wp-content/uploads/2019/07/Cigre-Symposium-Aalborg-Paper.pdf.
[18] Yang Z, Li K, Guo Y, Feng S, Niu Q, Xue Y, et al. A binary symmetric based hybrid meta-heuristic method for solving mixed integer unit commitment problem integrating with significant plug-in electric vehicles. Energy 2019;170:889–905. https://doi.org/10.1016/j.energy.2018.12.165.
[19] Sullivan JO, Rogers A, Flynn D, Smith P, Mullane A, Malley MO. Studying the maximum instantaneous non-synchronous generation in an island system—frequency stability challenges in Ireland. IEEE Trans Power Syst 2014;29(6):2943–51. https://doi.org/10.1109/TPWRS.2014.2316974.
[20] EirGrid. Operational constraints update 18/12/2019. 2019. http://www.eirgridgroup.com/site-files/library/EirGrid/OperationalConstraintsUpdateVersion1_89_December_2019.pdf.
[21] EirGrid. EirGrid Group achieves record level of variable renewable energy on Irish electricity system. 2018. http://www.eirgridgroup.com/newsroom/record-renewable-energy-o/.
[22] Eirgrid. DS3 programme operational capability outlook. 2016. http://www.eirgridgroup.com/site-files/library/EirGrid/DS3-Operational-Capability-Outlook-2016.pdf2016.
[23] Karbouj H, Rather ZH, Flynn D, Qazi HW. Non-synchronous fast frequency reserves in renewable energy integrated power systems: a critical review. Int J Electr Power Energy Syst 2019;106:488–501. https://doi.org/10.1016/j.ijepes.2018.09.046.
[24] Eriksson R, Modig N, Elkington K. Synthetic inertia versus fast frequency response: a definition. IET Renew Power Gener 2018;12(5):507–14. https://doi.org/10.1049/iet-rpg.2017.0370.
[25] DNV-GL. RoCoF alternative solutions technology assessment. 2015. http://www.eirgridgroup.com/site-files/library/EirGrid/RoCoF-Alternative-Solutions-Technology-Assessment-Phase-1-DNV-GL-Report_.pdf.
[26] RESERVE Project - List of Publications. https://www.re-serve.eu/files/reserve/Content/Scientific%20Publications/191009_List%20of%20publications.V4.docx.
[27] RESERVE Project. https://www.re-serve.eu/what.html. (Accessed 01/12/2019.
[28] Williams F. Reserve - second report on project progress. 2019. https://www.re-serve.eu/files/reserve/Content/Deliverables/727481_RESERVE_D8.2.pdf.

[29] EirGrid. DS3 Programme. http://www.eirgridgroup.com/how-the-grid-works/ds3-programme/.
[30] Battery assets lead winning projects in National Grid tender. Solar Portal Power 2016. https://www.solarpowerportal.co.uk/news/battery_assets_lead_winning_projects_in_national_grid_tender.
[31] Batteries. Beyond the spin. AES, Queen's University Belfast, Everoze; 2017. http://everoze.com/app/uploads/2019/11/Batteries_Beyond_the_Spin.pdf.
[32] MIGRATE project. 2019. https://www.h2020-migrate.eu/about.html.
[33] EU-sysflex project. 2019. https://eu-sysflex.com/about/.
[34] EPRS EU. Briefing common rules for internal electricity market. 2019. http://www.europarl.europa.eu/RegData/etudes/BRIE/2017/595924/EPRS_BRI(2017)595924_EN.pdf.
[35] EU. Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation. 2017. https://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1503656386035&uri=CELEX:32017R1485.
[36] ENTSO-E. ENTSOE 3rd DSA workshop notes and questions. 2019. https://docstore.entsoe.eu/Documents/Events/2019/190515_DSA_3rd%20StakeholderWorkshop%20-%20Notes%20and%20Questions.pdf.
[37] ENTSO-E. 1st DSA stakeholder workshop joint presentations. 2018. https://docstore.entsoe.eu/Documents/Events/2018/180523_DSA_SH_Workshop-Joint_presentation_with_conclusions.pdf.
[38] Questions and answers on the synchronisation of the Baltic States' electricity networks with the continental European network (CEN) IP/18/4284. European Commission; 2018. https://europa.eu/rapid/press-release_MEMO-18-4285_en.htm.
[39] Deane JP, Drayton G, Ó Gallachóir BP. The impact of sub-hourly modelling in power systems with significant levels of renewable generation. Appl Energy 2014;113:152–8. https://doi.org/10.1016/j.apenergy.2013.07.027.
[40] Energy-Exemplar. PLEXOS integrated energy model. 2016. http://energyexemplar.com/software/plexos-desktop-edition/. 8th July 2016.
[41] ENTSOE. TYNDP 2016 scenario development report. 2016.
[42] JRC. EMHIRES dataset Part I: wind power generation. European Meteorological derived High resolution RES generation time series for present and future scenarios. 2016. https://doi.org/10.2790/831549.
[43] Collins S, Deane P, Ó Gallachóir B, Pfenninger S, Staffell I. Impacts of inter-annual wind and solar variations on the European power system. Joule 2018;2(10):2076–90. https://doi.org/10.1016/j.joule.2018.06.020.
[44] ENTSO-E. Supporting document for the network code on load-frequency control and reserves. 2013. https://www.entsoe.eu/fileadmin/user_upload/_library/resources/LCFR/130628-NC_LFCR-Supporting_Document-Issue1.pdf.
[45] Deane J, Driscoll Á, Gallachóir BÓ. Quantifying the impacts of national renewable electricity ambitions using a North–West European electricity market model. Renew Energy 2015;80:604–9. https://doi.org/10.1016/j.renene.2015.02.048.
[46] EirGrid S. All island TSO facilitation of renewables studies. SONI, Dublin: Eirgrid; 2010.
[47] Cuffe P, Lannoye E, Keane A, Tuohy A. Unit commitment considering regional synchronous reactive power requirements: Costs and effects. 11th International Workshop on Large-scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants, Lisbon, Portugal. Energynautics.https://researchrepository.ucd.ie/handle/10197/5153.
[48] UTCE. Final Report System Disturbance 4th November, https://www.entsoe.eu/fileadmin/user_upload/_library/publications/ce/otherreports/Final-Report-20070130.pdf; 2006.
[49] Nedd M, Browell J, Bell K, Booth C. Containing a credible loss to within frequency stability limits in a low inertia GB power system. IEEE Trans Ind Appl 2019:1. https://doi.org/10.1109/TIA.2019.2959996.
[50] Energienet. Technical Regulation 325 for wind power plants above 11kV revision 4. 2017. https://en.energinet.dk/-/media/BD322E7805694462AB125E5B5D0D79BC.PDF?la=en&hash=DB619E3EAD98AD2F2691CEA0B68BE8B438F4B3FD.
[51] Denholm P, Hand M. Grid flexibility and storage required to achieve very high penetration of variable renewable electricity. Energy Pol 2011;39(3):1817–30. https://doi.org/10.1016/j.enpol.2011.01.019.
[52] Kiviluoma J, Meibom P, Tuohy A, Troy N, Milligan M, Lange B, et al. Short-term energy balancing with increasing levels of wind energy. IEEE Transactions on Sustainable Energy 2012;3(4):769–76. https://doi.org/10.1109/TSTE.2012.2209210.
[53] Ela E, Tuohy A, Milligan M, Kirby B, Brooks D. Alternative approaches for incentivizing the frequency responsive reserve ancillary service. Electr J 2012;25(4):88–102. https://doi.org/10.1016/j.tej.2012.04.015.
[54] Daly P, Ruttledge L, Power M, Flynn D. Emulated inertial response from wind power: ancillary service design and system scheduling considerations. 2016 CIGRE session. Paris, France: CIGRE; August 2016. p. 21–6. http://hdl.handle.net/10197/8200.
[55] Hartmann B, Vokony I, Táczi I. Effects of decreasing synchronous inertia on power system dynamics—overview of recent experiences and marketisation of services. International Transactions on Electrical Energy Systems 2019;29(12). https://doi.org/10.1002/2050-7038.12128.
[56] Ela E, Wang C, Moorty S, Ragsdale K, O'Sullivan J, Rothleder M, et al. Electricity markets and renewables: a survey of potential design changes and their consequences. IEEE Power Energy Mag 2017;15(6):70–82. https://doi.org/10.1109/MPE.2017.2730827.