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Understanding future power system challenges with higher renewables and electrification

Thesis presented by

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for the degree of

Doctor of Philosophy

University College Cork

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January 2022

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Declaration

"This is to certify that the work I, Laura Mehigan, am submitting is my own and has not been submitted for another degree, either at University College Cork or elsewhere. All external references and sources are clearly acknowledged and identified within the contents. I have read and understood the regulations of University College Cork concerning plagiarism."

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Laura Mehigan

Acknowledgements

To my supervisory team of Dr Paul Deane, Professor Brian Ó Gallachóir and Professor Valentin Bertsch, thank you for your advice, supervision, guidance and for giving me the opportunity to work on industry relevant projects. Above all, thank you for your endless encouragement not just to progress my research but to keep a healthy work-life balance while doing so - it made all the difference!

My gratitude goes to Professor Joe DeCarolis for his hospitality during my visits to North Carolina, Dr Aoife Foley for the advice and invaluable insights into the journal editorial process, and to all collaborators on the CREDENCE project.

Thanks to Alessia Elia, Alparslan Zehir, Angela Pope, Aoife Dunne, Barry Hayes, Connor McGookin, Conor Hickey, Emma Hanley, Evan Boyle, Fiac Gaffney, Fionn Rogan, Hannah Daly, Ibrahim Sengor, Jason McGuire, Maarten Brinkerink, Mitra Kami Delivand, Seán Collins, Shane McDonagh, Siddharth Joshi, Tara Reddington, Tomás Mac Uidhir, Vahid Aryanpur, Vera O'Riordan and Xiufeng Yue, along with all others in the wider EPMG group, the ERI and MAREI with whom I've worked over the years. You have enriched my journey in various ways be it help and advice, collaborations, fresh perspectives, chats over tea, walks to clear the head, lockdown recipes, and good humour. Kudos also to all members of the `*hive brain'* that is the ERI Postgrads What's App group, a formidable source of banter and knowledge!

To my family and friends, near and far, I am so grateful for your constant love and support and for all the candles lit over the last few years! Mom and Dad, I could never convey the credit you deserve for helping me get to this point. I will be forever thanking you for all that you do and have done for me and my peeps. As Grandda Jack often said: "*you are the best of the best*".

James, Lily, and Molly, my three Mehigos, your smiles, hugs, kisses, and *joie de vivre* make even the hardest day worthwhile, and your welcome (and sometimes unwelcome!) distractions reminded me of the important things in life throughout my PhD journey.

Last, but certainly not least, Arthur, I'm so lucky to have you by my side for all of life's adventures, thank you for being you x.

Executive Summary

Urgent action to reduce global greenhouse gas emissions is needed to prevent irreversible damage to the world's climates. An opportunity exists to decarbonise electricity systems and to aid decarbonisation of heat and transport through electrification. This can only be achieved if electricity systems incorporate significantly higher levels of renewables and can cope with higher electrification. However, achieving this is not without its challenges particularly in the decade to 2030. Failure to make meaningful progress in this crucial decade will reduce the likelihood of meeting the commitments under the Paris Climate Agreement.

To solve these challenges, they must first be understood. The central focus of this thesis is to improve the understanding of the challenges faced by future electricity systems with higher Renewable Energy Sources (RES) and higher electrification with an emphasis on the European power sector for the year 2030. The thesis investigates the role of Distributed Generation (DG) in future electricity systems and acknowledges that while the role of DG is important it is not the key determinant of the challenges faced in future electricity systems. The challenge of declining rotational inertia from synchronous generators is investigated and the impact of managing rather than solving this challenge is quantified for every synchronous area in the pan European power system. An exploration of how carbon price influences the role of flexibility providers (batteries and interconnection) in decarbonisation of the European power system for a policy relevant scenario reveals new insights. These insights include the importance of a high carbon price to ensure that flexibility providers reduce emissions while fossil fuels remain in the generation mix, batteries reduce solar curtailment more than interconnection, and interconnection reduces wind curtailment more than batteries.

The main contributions of the thesis are the methodological contributions and insights gained into the future challenges from both a synchronous area level and a broader European perspective. The work undertaken as part of this thesis has accelerated discussions on the challenges that will be faced to achieve renewable ambitions in 2030. In particular, this research has contributed to a recent policy decision in Ireland on the need for backup generation in 2030 and during the transition to a decarbonised system.

Nomenclature

Abbreviations

AC	Alternating Current
ATC	Available Transfer Capacity
BES	Bulk Electric System
BESS	Battery Energy Storage System
BTM	Behind the meter
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CE	Continental Europe
CHP	Combined Heat and Power
CO_2	Carbon dioxide
DC	Direct Current
DER	Distributed Energy Resource
DG	Distributed Generation
DSR	Demand Side Response
EC	European Commission
ENTSO-E	European Network of Transmission System Operators of Electricity
ERCOT	Electric Reliability Council of Texas
ES	Energy Storage
ESR	Effort Sharing Regulation
ETS	Emissions Trading Scheme
EU	European Union
FFR	Fast frequency response
GB	Great Britain
GHG	Greenhouse Gas
HV	High voltage
HVDC	High Voltage Direct Current
IC	Interconnection
IEM	Integrated energy model
IPCC	Intergovernmental Panel on Climate Change
LCC	Lifecycle cost

LCOE	Levelised cost of electricity
LDC	Load duration curve
LV	Low voltage
MC	Marginal cost
MILP	Mixed integer linear programme
MV	Medium voltage
NCSO	Network Code of System Operation
OCGT	Open Cycle Gas Turbine
P2G	Power to Gas
PV	Photovoltaic
RED	Renewable Energy Directive
RES	Renewable Energy Sources
ROCOF	Rate of Change of Frequency
SEF	Strategic Energy Framework
SEM	Single Energy Market
SRMC	Short Run Marginal Costs
SNSP	System Non-synchronous Penetration
TSO	Transmission System Operator(s)
TYNDP	Ten Year Network Development Plan
UCED	Unit Commitment and Economic Dispatch
UN	United Nations
UK	United Kingdom
NGUK	National Grid UK
V2G	Vehicle to Grid
VRE	Variable renewable energy
VRES	Variable renewable energy sources

Units

GJ	Gigajoule
GW	Gigawatt
GWh	Gigawatt hour
GWs	Gigawatt seconds
Hz	Hertz

MVA	Megavolt-ampere
MW	Megawatt
MWh	Megawatt hour
MWs	Megawatt seconds
t	tonne
TW	Terawatt
TWh	Terawatt hour

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

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Chapter 1: Introduction

1.1 Background

Action is urgently needed to reduce Greenhouse Gas (GHG) emissions to prevent irreversible damage to global climatic systems [1]. The energy sector is an obvious focal point for scrutiny as it contributes circa 75% of global GHG emissions [2]. Electricity contributes 36% of all energy related carbon dioxide (CO_2) emissions globally [3] and accelerating the increase of Renewable Energy Sources (RES) could reduce this significantly and provide an opportunity to decarbonise other sectors such as heat and transport through electrification.

To appreciate the challenges faced, it is important to envision the possible shape and composition of future electricity systems. This helps to identify the challenges that are common to all possible futures and those that are unique to individual ones. Increased renewables and electrification drive a more decentralised electricity system [4] but this can be coupled, as it is in Europe, with a drive to greater centralisation through increased interconnection between countries and electrically islanded systems [5]. Exploring the role of distributed generation (DG) is critical to advance discussions on the mix of centralisation and decentralisation in future electricity systems.

The next decade has been recognised as crucial in the fight against climate change [1, 6]. Europe aims to become the first climate neutral continent [7] and fulfil an economy wide net-zero GHG ambition by 2050. Electricity is expected to play an important role in achieving Europe's ambition, fulfilling up to 60% of primary energy demand in some scenarios, through the rapid deployment of renewables and increased electrification [8, 9]. Over the last twenty years there was notable progress within the electricity sector in increasing the penetration of RES and record increases are forecasted again for 2021 [6]. Variable RES (VRES) in the form of wind and solar make up the bulk of these increases. However, the pace of renewables build-out needs to accelerate, and this requires an examination of the technical challenges of operating power systems at high penetrations of RES.

As VRES such as wind and solar proliferate, fossil fuel fired synchronous machines are displaced. These synchronous machines traditionally provided the required level of system rotational inertia to dampen frequency oscillations, reactive power support to aid voltage control and system stability, blackstart capability to restart the system after a blackout, short circuit current to ensure protection relays operate correctly, reserve to cope with power mismatches, ramping capability to respond to changing demand/generation and more. With the contributions of synchronous machines diminishing, these requirements must be met by other means. In addition, as the generation mix becomes RES dominated, weather will have a more significant impact on the system. More flexibility will be required to cope with the increased variability and the system will have to be robust enough to meet demand even when the weather is not conducive to high renewable outputs.

Time is of the essence when it comes to reducing emissions as the earlier emissions are reduced the better due to the cumulative effect year on year, which will reduce the burden of change required later [10]. There are less than 30 years to 2050, this may provide time for new technologies to mature, for suitable markets to develop or policy support to be sufficiently developed to encourage investment in economically challenging technologies. For the crucial timeframe out to 2030, however, it is a risky strategy to rely on new technologies alone to solve these challenges. A more conservative approach is to ascertain the impacts of utilising existing technologies or proven approaches to resolve or at least alleviate these problems.

The speed European Member States reduce emissions in pursuit of the common net zero goal is and will not be uniform [11]. This is caused by a myriad of reasons including different potentials of natural resources, different existing generation portfolios, and different existing internal and cross-border infrastructure amongst Member States. Consequently, Member States and the synchronous area(s), which they are part of, will face technical challenges at different times during the transition. With the push towards increased interconnection, solutions to an expected technical challenge in one Member State or synchronous area need to be considered from a wider perspective. Furthermore, when a solution is proven to alleviate or overcome a particular problem due to higher VRES or electrification it may be an option for other jurisdictions facing the same problem at a later stage.

A case in point of the different speeds of encountering problems is the inertia issue in the synchronous area of Ireland and Northern Ireland. Over a decade ago concerns about inertia were investigated [12]. This resulted in the implementation of minimum inertia constraints for power system operation. While these constraints have been reduced from what they first were due to the introduction of other measures [13], inertia constraints are still in place in 2021. This solution was envisaged to be temporary and was implemented in the All-Island electricity system to allow increased penetration of RES with a view to achieving a renewable electricity target of 40% in Ireland by 2020. The solution was not considered in the context of the wider European system prior to implementation, nor was consideration given to the wider impact when this temporary solution may be replaced with a longer-term solution.

In Europe, consumers are accustomed to a safe, secure, and reliable power system and any change to this could jeopardise the shift to electrified heat and transport. Electricity demand will still have to be met during periods of cold dark calm weather over a large portion of the continent.

The motivation for this thesis is to improve understanding of the challenges of higher RES and electrification with a particular focus on Europe at the end of this crucial decade (i.e., 2030). It does this by considering the mix of centralisation and decentralisation of electricity systems and the role of DG, quantifying the impact of inertia constraints, and investigating the roles of batteries and interconnection in decarbonisation, rounded off with a consideration of the potential shape of one synchronous area in Europe (the All-Island electricity system) presented in Annex 1.

1.2 Thesis Aims

The overall aim of this thesis was to improve understanding of future power systems challenges of higher electrification and renewables and to advance appropriate methods to achieve this aim. The core objective of the thesis is to address the following four specific research questions that each contribute to the overall aim:

RQ1: What role will DG hold in future electricity systems?

RQ2: What existing or envisaged tool or combination of tools could model future electricity systems with DG?

RQ3: What impact will rotational inertia constraints have in the European power system?

RQ4: What will the impact of increased batteries and interconnection be on decarbonisation of the European power system?

The following section describes the structure of the thesis highlighting where these research questions have been addressed.

1.3 Thesis in Brief

Chapter 2 (RQ1 and RQ2): This chapter provides a comprehensive review of the existing literature on distributed generation and the factors that influence its role in the shaping of future electricity systems. It explores these often-interrelated factors highlighting the challenges faced in future electricity systems. A review of modelling tools explores the main tools that can be used for modelling electricity systems of the future with DG. It highlights the difficulty of finding a tool that can fully model future electricity systems with DG in the context of the wider energy system and suggested a technique for overcoming this.

Chapter 3 (RQ3)**:** One of the system challenges identified in chapter 2, declining inertia from conventional synchronous machines, is explored in more detail in this chapter. The TSO in Ireland and Northern Ireland are presently using inertia constraints to address this challenge. One of the tools identified in Chapter 2 is used to consider the inertia challenge from a wider European perspective. The impact of adopting inertia constraints in the future European power system in terms of cost, curtailment, and emissions is quantified. In addition, an assessment of inertia distribution across the Continental European (CE) system is conducted. The risk of insufficient inertia in the Iberian Peninsula for the loss of connection to the CE synchronous area is singled out in the discussion. Coincidentally, this contingency happened earlier this year with a Rate of Change of Frequency (ROCOF) of |0.6|Hz/s and |1|Hz/s recorded on the Iberian Peninsula [14]. This highlights the relevance of this chapter which considered ROCOF limits of |0.5| Hz/s and |1| Hz/s for quantifying the impact of inertia constraints.

Chapter 4 (RQ4): Increased renewables coupled with increased electrification is required to reduce emissions. However, investment risk in the form of curtailment could deter additional investment in renewables and thus jeopardise emissions reductions. Power systems will have to be more flexible to cope with the variability brought by increased renewables. Batteries and interconnection are two such technologies which can provide flexibility. Using a methodological approach identified in Chapter 2, this chapter presents a study that explores 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, in a policy relevant future European power system.

Annex 1 provides an abridged version of a report I was invited to be lead author of, due to my previous industry experience and my research into the future of the electricity systems and the challenges faced. The report 'Our Zero e-Mission Future' focused on the All-Island electricity system of Ireland and Northern Ireland in 2030. The All-Island electricity system is a relatively isolated system with only two HVDC links to the UK, yet it has achieved high penetrations of renewables. It has achieved instantaneous penetration of non-synchronous generation of over 70% and ambition to go as far as 95% by 2030 [15]. It provides an interesting test case for other European synchronous areas that have yet to face such significant penetrations of non-synchronous renewables. Several scenarios and sensitivities were conducted to explore the potential make-up of a 2030 electricity system in Ireland and Northern Ireland that is reliable even during periods of cold, calm, dark weather. It considers system services, interconnection, and battery capacity as well as system constraints such as rotational inertia. It also featured an analysis of weather extremes considering 30 years of weather data.

Chapter 5, the final chapter, presents the conclusions drawn based on the content of this thesis with recommendations for building on it in the Future Work section. A diagrammatic overview of the thesis is presented in Figure 1-1 below. It is recommended that the thesis is read in the following order: Chapter 1 – 4, Annex 1 followed by Chapter 5.

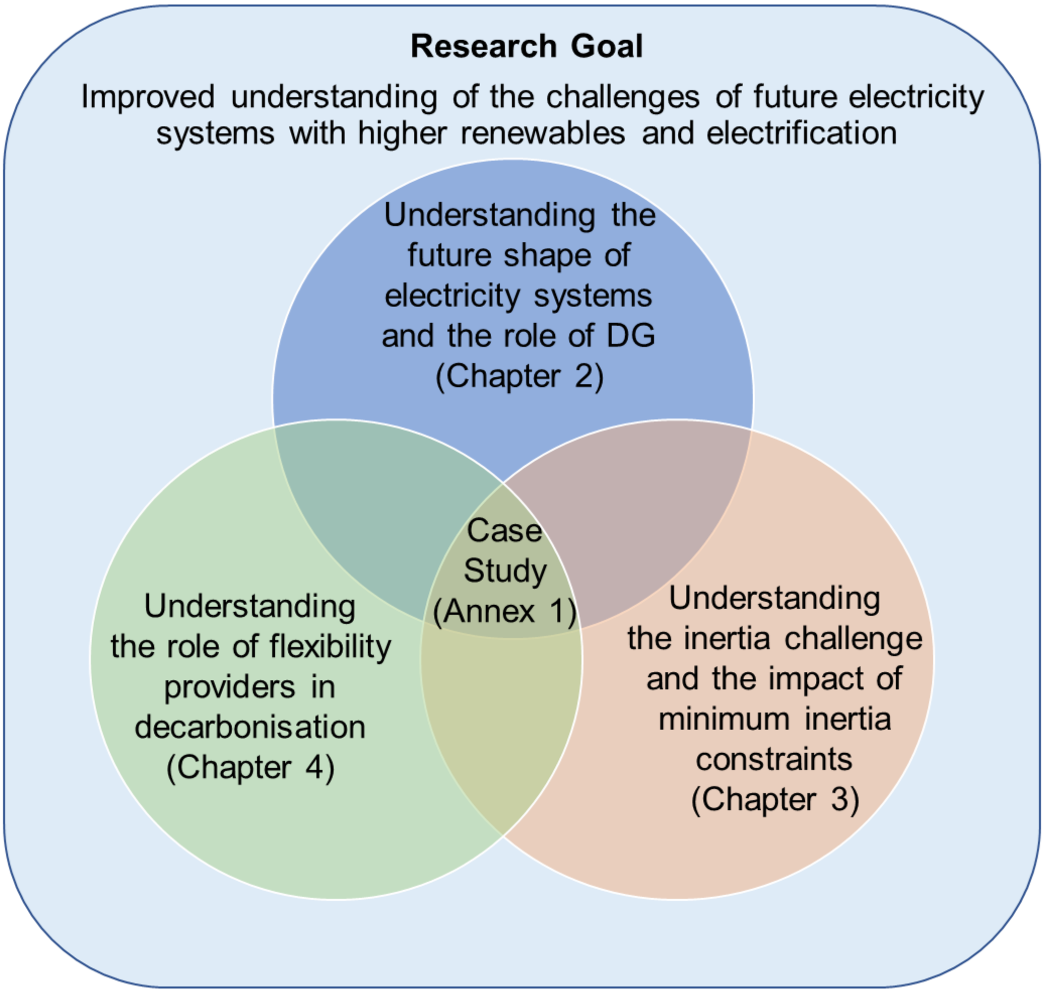


Figure 1-1: Overview of thesis

1.4 Scope & Methodology

There are several challenges faced by electricity systems with increasing RES and electrification. These challenges can be investigated from several different perspectives. Accordingly, there is a wide array of models that could be used. The scope of this work is limited to the perspective of how existing or proven technologies to address the challenges such as inertia and flexibility can affect decarbonisation and renewable curtailment in the European power system in the next crucial decade. It also includes an in-depth look at one synchronous area in 2030, the All-Island power system of Ireland and Northern Ireland. The scope does not extend to detailed network and stability analysis.

1.4.1 Soft-linking and Unit Commitment and Economic Dispatch (UCED) modelling

The electricity system is an inherent part of the energy system. Thus, when considering the challenges faced by electricity systems with increasing renewables and electrification it is important to reflect the influence of the wider energy system within the modelling. This can be achieved by using robust scenarios or soft-linking, as identified in the review of modelling tools conducted in Chapter 2. Soft-linking of two or more models leverages the strengths of each individual model enhancing overall understanding of the system being investigated. Although, soft-linking, particularly unidirectional soft-linking, is not without its drawbacks as each model optimizes individually and independently rather than collectively [16], it avoids the need to incorporate the models into one comprehensive tool. This reduces complexity and the computational power required [17].

Using a soft-linking approach enabled the pertinent outputs of one model or methodology capturing the influence of the wider energy system, such as generation mix, electricity demand, fuel costs and so on, to be captured as inputs to more detailed power system models for Chapter 3 and 4. The detailed power system models are then used to fulfil the aim of the thesis by exploring in detail the challenges of rotational inertia (Chapter 3) and flexibility (Chapter 4) faced by future electricity systems with increased electrification and renewables.

The detailed power system models used for this thesis were Unit Commitment and Economic Dispatch (UCED) models. These models optimise the generation outputs of a given generation portfolio to meet electricity demand at a prescribed temporal resolution taking into consideration technical and operational constraints. The platform used for this modelling was Energy Exemplar's PLEXOS® Integrated Energy System Modelling software [18]. It is a commercial tool widely used in industry and academia, with free licences available to academics. This tool allows users to view, edit and share the fundamental linear programme equations, making it a transparent modelling tool for research. In built technical constraints such as generator ramp rates and minimum on/off times and so on are used in addition to custom constraints such as those used in Chapter 3 for prescribing ROCOF constraints. All the models used for this thesis are models of the pan European power system and provide simulations at hourly resolution for the year 2030, the end of this critical decade.

1.4.2 Pan European Model

The studies presented in Chapter 3, 4 and Annex 1 are performed with a pan-European electricity dispatch test system with hourly resolution developed in an Integrated Energy Model (IEM) in PLEXOS Simulation Software. The objective function is set to minimise 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 [19]. The optimization problem, in the form of a mixed integer linear programme (MILP), is solved for each hour of a 24-hour rolling horizon with a 6-hour look ahead for the year studied, 2030. Standard generator characteristics by generator type are used, alleviating the need to have detailed generator data of all existing generators across Europe and to make assumptions on which units retire between now and 2030. Twenty-eight nodes are included in the model considered to be in 5 synchronous areas as follows: The All-island Electricity system (Ireland and Northern Ireland), Great Britain, the Nordic States (Finland, Norway, and Sweden), the Baltic States (Estonia, Latvia, and Lithuania) and Continental Europe (Austria, Belgium, Bulgaria, Croatia, Czechia, Denmark, France, Germany, Greece, Hungary, Italy, Luxembourg, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, and Spain). The transmission capacity between these nodes is modified to the ENTSO-E's Reference Capacities for 2030 in Chapter 3 [20] and Chapter 4 and Annex 1 [21].

The same approach is adopted for the European model used in Annex 1. However, there are some notable differences as the focus of the study is specifically on the All-Island electricity system of Ireland and Northern Ireland: (1) the generator data for Ireland and Northern Ireland is standardised specific to available data for Ireland and Northern Ireland rather than across all of Europe (2) operational constraints are applied specific to Ireland and Northern Ireland only and (3) Interconnection capacity is modified in line with the TSO forecast for Ireland/Northern Ireland.

1.5 Thesis Outputs

1.5.1 Peer Reviewed Journal Papers

L. Mehigan, J. P. Deane, B. P. Ó. Gallachóir and V. Bertsch (2018). "A review of the role of distributed generation (DG) in future electricity systems." Energy 163: 822-836.

L. Mehigan., D. Al Kez, S. Collins, A. Foley, B. Ó'Gallachóir and P. Deane (2020). "Renewables in the European power system and the impact on system rotational inertia." Energy 203: 117776.

L. Mehigan, B. Ó'Gallachóir and P. Deane. "Batteries and interconnection – competing or complementary roles in the decarbonisation of the European power system?" (In Review Renewable Energy)

Al kez, D., A. M. Foley, N. McIlwaine, D. J. Morrow, B. P. Hayes, M. A. Zehir, **L. Mehigan,** B. Papari, C. S. Edrington and M. Baran (2020). "A critical evaluation of grid stability and codes, energy storage and smart loads in power systems with wind generation." Energy 205: 117671.

P. Hoang, G. Ozkan, P. Ramezani Badr, B. Papari, C. Edrington, M.A. Zehir, **L. Mehigan**, B. Hayes, D. Al kez, Dlzar, A.M. Foley. A Dual Distributed Optimal Energy Management Method for Distribution Grids with Electric Vehicles". IEEE Transactions on Intelligent Transportation Systems, Doi: 10.1109/TITS.2021.3126543.

1.5.2 Conferences and Invited Talks

Mehigan, L., 'The All-Island Electricity System in 2030'. 2021 Irish Renewable Energy Summit, 25th February 2021

Mehigan, L., 'Our Zero e-Mission Future'. Launch of Our Zero e-Mission Future report, 20th November 2020

Mehigan, L., 'How to decide the mix of Centralisation and Decentralisation of Future Electricity Systems?', CREDENCE Project Stakeholder Engagement. 12th May 2017. Dublin, Ireland.

Mehigan, L., 'How to decide the mix of Centralisation and Decentralisation of Future Electricity Systems?', CREDENCE Project Annual Conference. 4th December 2017. North Carolina State University, Raleigh, North Carolina

1.5.3 Reports

Mehigan, L., Deane, JP., Our Zero e-Mission Future, 2020. [22]

1.6 Role of Collaborations

While this thesis is my own work it has been enhanced by the collaborative research with other academics and industry professionals. In this section the contributions of others are described.

- **Chapter 2** is based on a published peer-reviewed journal paper for which I was the lead author. I wrote this chapter in its entirety while Professor Brian Ó Gallachóir and Professor Valentin Bertsch and Dr Paul Deane provided guidance and reviewed drafts.
- **Chapter 3** is based on a published peer-reviewed journal paper for which I was the lead author. I wrote this chapter in its entirety. Dr Seán Collins assisted with data curation and reviewed drafts. Dr Paul Deane validated the model, reviewed drafts and together with Professor Brian Ó Gallachóir provided overall guidance. Dr Aoife Foley provided guidance on the visualisation of the work and with Dlzar Al kez reviewed drafts.
- **Chapter 4** is based on a published peer-reviewed journal paper for which I was the lead author. I wrote this chapter in its entirety. I developed the model for the European power system, Dr Paul Deane and Professor Brian Ó Gallachóir reviewed drafts and provided overall guidance.
- **Annex 1** presents a shortened version of a report I co-authored with Dr Paul Deane which focused on the All-Island electricity system and the potential paths and challenges to decarbonisation. I updated the European power system model used for Chapter 3 of this thesis and enhanced it with more specific detail for the All-island electricity system for this work. Dr Paul Deane provided guidance, validated the model, and contributed the policy insights as well as technology potentials post 2030. The remainder of the report was a joint effort. The work was funded by the Electricity Association of Ireland.

1.7 Contributions

This section briefly describes the contributions of this thesis to the knowledge base on the challenges of future electricity systems with increased RES and electrification. The level of DG and its location will influence the likely shape a future electricity system may take in terms of centralisation or decentralisation. This thesis provides a full overview of the often-interacting factors that influence the role of DG. It provides a qualitative assessment of the uncertainty associated with these factors. This enables appropriate selection of modelling tools for exploring the potential impacts that a factor can have on future DG deployment and consequently future electricity system development. A review of modelling tools that can incorporate these factors and DG and a description of the ideal modelling tool is also provided along with a suggested methodological framework to overcome the challenges of creating the ideal tool.

This thesis considers the challenges from a wider European perspective. It quantifies the impact of minimum inertia requirements, an approach currently adopted in one synchronous area in Europe (the All-Island electricity system), to manage the challenge of declining rotational inertia across the European power system due to increasing renewables for two divergent renewable ambition scenarios. The work advances existing methodologies investigating inertia using a soft-linking approach by considering two divergent decarbonisation scenarios and two ROCOF limits, and by analysing the distribution of inertia across Member States. The results of the power system modelling performed serve to provide caution against the enduring use of minimum inertia constraints beyond the transition period due to the potential detrimental effects on emissions reductions. The analysis highlights the impact that neighbouring synchronous areas can have on each other, thereby demonstrating the benefit of considering the challenges from a wider perspective. Insights are provided on the areas and countries that are potentially at risk due to localised inertia deficits for the Continental European synchronous area.

Focusing on proven technologies, the thesis demonstrates the circumstances required to ensure that the flexibility providers, batteries and interconnection, can be useful to emissions reductions and alleviation of renewable curtailment in Europe. The methodological contribution of this part of the investigation centres on the use of a policy relevant base scenario and the analysis of curtailment impact on individual renewable technologies. The work considers the impact of batteries and interconnection on curtailment on wind and solar jointly and individually thereby identifying the additional benefit to solar from battery deployment and the additional benefit to wind from interconnection development.

Finally, Annex 1 of this thesis examines the different policy levers that influence emissions in the All-island electricity system such as increased electrification, higher renewables build out, a more flexible system, and less constrained system. The methodological achievement of Annex 1 is the robust and efficient distilment of UCED results using 30 years of weather data to several 2-week windows pinpointing generation dispatch extremes on the electricity system on the island of Ireland. Using a format and approach suitable for the wide target audience of electricity stakeholders ranging from government and utility companies to the end users of electricity, it improves understanding in the wider community of the challenges and the scale of transformation required to achieve a system with emissions that are broadly in line with the requirements under the Paris Agreement 2015, that is one with higher renewables and higher electrification.

Chapter 2: A Review of the Role of Distributed Generation (DG) in Future Electricity Systems

2.1 Abstract

The traditional paradigm of centralised electricity systems is being disrupted by increasing levels of distributed generation. It is unclear as to what level of distributed generation is expected, appropriate or optimal in future power systems. Many researchers have focused on how to integrate distributed generation into centralised electricity systems. Such research tends to consider optimality from narrow viewpoints focused on particular aspects of the electricity network such as the distribution network within the confines of a vision of future electricity systems where centralised infrastructure remains. There is a gap in the literature in considering the role of distributed generation (DG) within the context of the entire electricity system and the wider energy sector and how it can drive the development of an electricity system to maintain a centralised approach or increase decentralisation. This paper explores the factors that influence the role of DG in future electricity systems and the existing tools that can be used to explore how these factors can impact the role of DG considering four future visions for electricity systems each with increasing levels of decentralisation. The review concludes that there is no one tool that can be used to explore all the factors and their impact on the role of DG.

2.2 Introduction

Since the advent of Alternating Current (AC) electrical systems and the ability to transfer bulk power over long distances, the top-down paradigm has dominated electricity generation and supply. This involved large scale generation feeding into high voltage transmission systems which transported power to medium voltage distribution networks and on to low voltage customer level. Today, this paradigm of centralised power systems is being disrupted by increasing amounts of generation and other energy resources connected at distribution level and behind the meter at industrial and residential customers' sites [23].

Researchers agree that distributed generation (DG) has a role to play in the future of electricity systems [24, 25] in addition to energy storage and demand response. However, the degree of change in future electricity systems is uncertain as it depends largely on the level of deployment of DG and other distributed energy resources (DERs). Funcke and Bauknecht presented a typology based on the location of generation resources and operational methods of system balancing for describing visions of centralised and decentralised electricity systems in [26]. Loosely based on that typology we consider four possible future visions of future electricity systems for the purpose of this paper (see Figure 2-1).

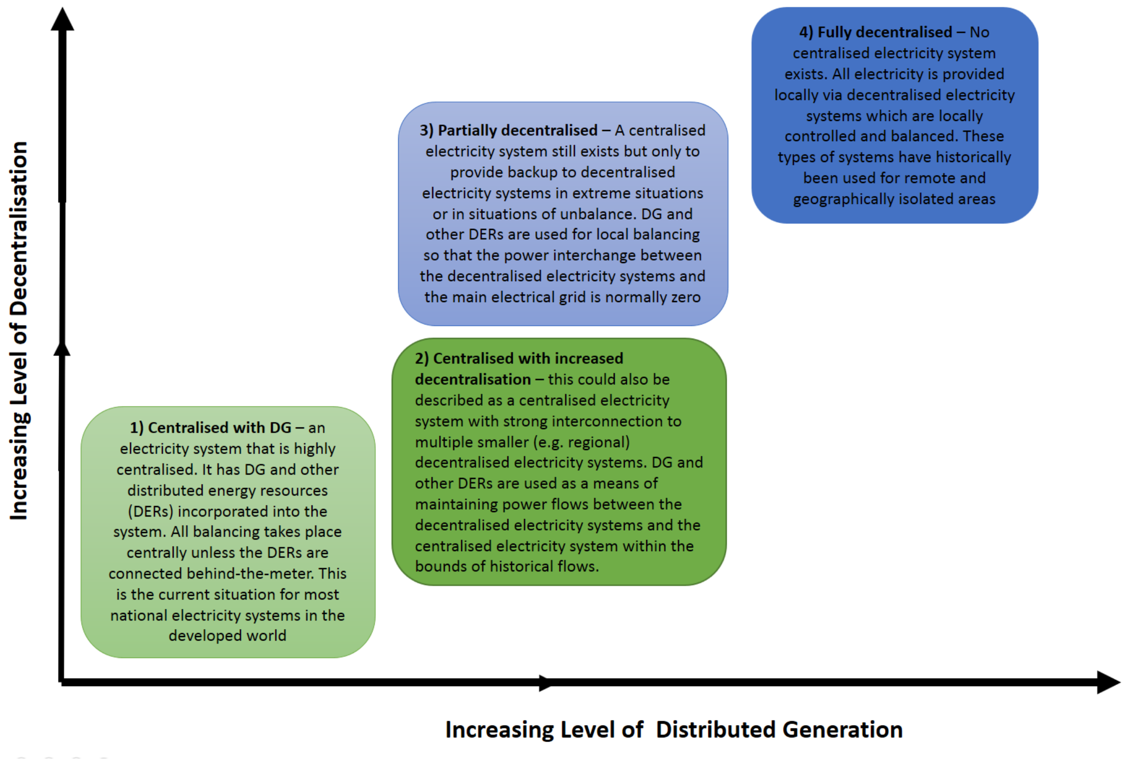


Figure 2-1: Possible topologies of future electricity systems

The trajectory of development of an electricity system towards one of the four visions will depend largely on the future role of DG and other DERs. Exploring the factors that influence the role of DG in future electricity systems will improve understanding of the trade-offs between maintaining a centralised approach and increasing decentralisation.

The research questions of what factors influence the role of DG in future electricity systems and what tool or tools can be used to understand the impact of those factors have not been fully answered previously. For example, the factors that could help achieve increased levels of embedded DG in distribution networks have been investigated previously but the tools discussed pertained to the distribution network only and not the entire electricity system [27]. Similarly, Huda and Zivanovic [28] and Manfren et al. [29] recently presented papers reviewing models and tools for the large scale integration of DG and distributed generation planning respectively but again they were specifically focused on the distribution system and project level and did not include the entire electricity system. In the broader energy system context, a survey of developers of energy tools and models was undertaken by Connolly et al. presented in [30] particularly concerned with the ability to simulate the integration of renewable energy however DG was not specifically considered. Hall and Buckley [31] reviewed energy system models used in the UK but the focus was on classification of the models reviewed rather than DG. A review which discussed the evolution of electricity models through market liberalisation was presented by Foley et al. in [32], again this was not focused on DG.

This paper aims to address a gap in the literature by presenting the factors that influence the role of DG and the existing tools that can be used to explore the impact those factors have on the development of future electricity systems. The paper also highlights how the deployment of DG and other DERs can drive future electricity systems towards one or other of the possible visions already described. Unlike previous work, this review is not limited to a particular part of the electricity network. It looks at the entire electricity system as well as the interactions with the wider energy system.

The remainder of this section provides the relevant definitions and discusses the drivers and benefits of DG deployment. Section 2.3 presents the main factors that can influence the level of DG deployment and how they can drive centralised or decentralised vision of future electricity systems. Section 2.4 describes the "ideal" tool and explores which existing tools can be used to explore the role of DG and the factors that may influence it for the visions of future electricity systems described. The challenges for modelling the role of DG in future electricity systems are discussed in Section 2.5, while a conclusion and areas of future research are presented in section 2.6.

2.2.1 Definitions of Distributed Generation (DG), Distributed Energy Resource (DER) and Distributed Energy Storage

There is no internationally accepted definition of DG. DG has been described as being generally small scale [33], mainly renewable and close to the load it feeds [24]. However, it can also include larger scale, non-renewable generation [34] connected to anywhere in the distribution system thus it has proved difficult for researchers to conclusively define or classify. Acknowledging the lack of consensus on a definition of DG, Pepermans et al. presented a review [35] of available definitions and categorisations of DG. They concluded that although vague the best definition was provided by Ackermann et al. in 2001 [36] "an electric power generation source that is connected directly to the distribution network or on the customer side of the meter". This definition implies that DG is always connected to metered or networked infrastructure. This is not always the case particularly for developing countries where distributed generation can provide an alternative to grid connected electricity supply. The total percentage of DG in the EU was approximately 7 % in 2011 [37] and the EU's definition of DG concurs to some extent with Ackermann et al. [38]: "distributed generation means generation plants connected to the distribution system".

The North American Electric Reliability Corporation (NERC) distinguishes between distributed generation and behind the meter generation in [38] and considers both of these in addition to storage, aggregation, microgrids, co-generation and backup generation under the umbrella term of distributed energy resources (DERs). The official NERC definition of DER is somewhat opaque: "A Distributed Energy Resource (DER) is any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES)." Delving into NERCs definition of a BES [39] provides a little more clarification on that definition by confirming that BES refers to all transmission elements and power resources connected at 100kV and above that are not considered to be part of the local distribution network. On the other hand the EU considers DERs to comprise of DG, demand response (DR) and energy storage (ES) [40].

The US Department of Energy (DOE) provides a clear explanation of energy storage [41]. In more recent times the EU has proposed a definition for energy storage which is quite similar to the US DOE definition [42]: "'energy storage' means, in the electricity system, deferring an amount of the electricity that was generated to the moment of use, either as final energy or converted into another energy carrier." Neither the EU nor the US DOE provide definitions for distributed storage or distributed energy storage, although the terms are regularly used in EU reports [43, 44]. Peer reviewed literatures do not provide a clear definition of distributed energy storage either. Similar to DG, location, size and point of connection to the electricity grid are implied as the distinguishing factors between distributed and bulk energy storage [45].

Due to the lack of unanimity researchers often provide their own meaning of DG [46-48] as we will in this paper. The definition assumed for the remainder of this paper is: Distributed generation is an electric power generation source, which can also be considered to be a DER, that is (a) connected to the distribution network (b) the customer side of the meter or (c) isolated from the grid and local to the demand it supplies. Similarly, distributed storage is defined as storage that is (a) connected to the distribution network (b) the customer side of the meter or (c) isolated from the grid and local to the demand it can supply and resources it can be supplied by.

2.2.2 Drivers and benefits of distributed generation deployment

The predominant driver cited for the increasing deployment of distributed generation is the environmental benefits associated with a reduction in greenhouse gas emissions [49-51]. Garcez [52] also found climate change was the most cited motivating factor in a systematic literature review focused solely on the Americas. However, achieving environmental benefits through use of DG is dependent on the technology employed as the encouragement of DG without consideration of the fuel mix could result in increased numbers of fossil fuelled DGs being deployed to the detriment of the environment [53].

Renewable Energy (RES) Targets [50, 54-56] increased electricity demand [50, 56, 57], government policies [48, 58], regulation [54, 59], market liberalisation [35, 49] and lower capital cost [60, 61] are other drivers cited in the literature. Energy security is mentioned as both a driver and a benefit of increased DG deployment assuming an increased diversification of fuel mix [24, 29, 34, 35, 40, 47, 49, 55, 57, 62-64] as is deferral of network investments [24, 29, 34, 35, 43, 46, 47, 49, 51, 60, 61, 64-67]. Bottom-up drivers reflect customer choices, an example of one such driver cited in the literature is the increased customer appetite for a resilient and highly reliable electricity supply [48, 49, 68].

Many of the technical benefits mentioned concern decreased network losses if employed close to load [24, 25, 28, 34, 47, 55-57, 60, 66, 69-72], improved voltage profile/regulation [28, 34, 65, 66, 70, 73] and reliability enhancement [34, 46, 49, 50, 56, 57, 66, 67, 70, 73]. However, these technical benefits can only be realised by selecting the optimal placement, size, technology types and volume within the network. Installing higher levels than optimal or suboptimal planning can introduce network problems [70].

2.3 The factors that can influence the future role of DG in electricity systems

There is a diverse range of often interconnected factors that can influence the future role of DG in electricity systems as illustrated in Figure 2-2. This section will explore these factors and qualitatively attributes a level of uncertainty to each category of factors. The attributed levels of uncertainty should be understood in relative terms (comparison between the different factors) rather than absolute terms. Understanding the level of uncertainty associated with a factor is key to selecting the right approach for modelling the potential impacts that factor can have on future DG deployment and consequently future electricity system development. For example, if each factor had a low level of uncertainty, it would be easy to understand the future role of DG with less complex deterministic modelling tools.

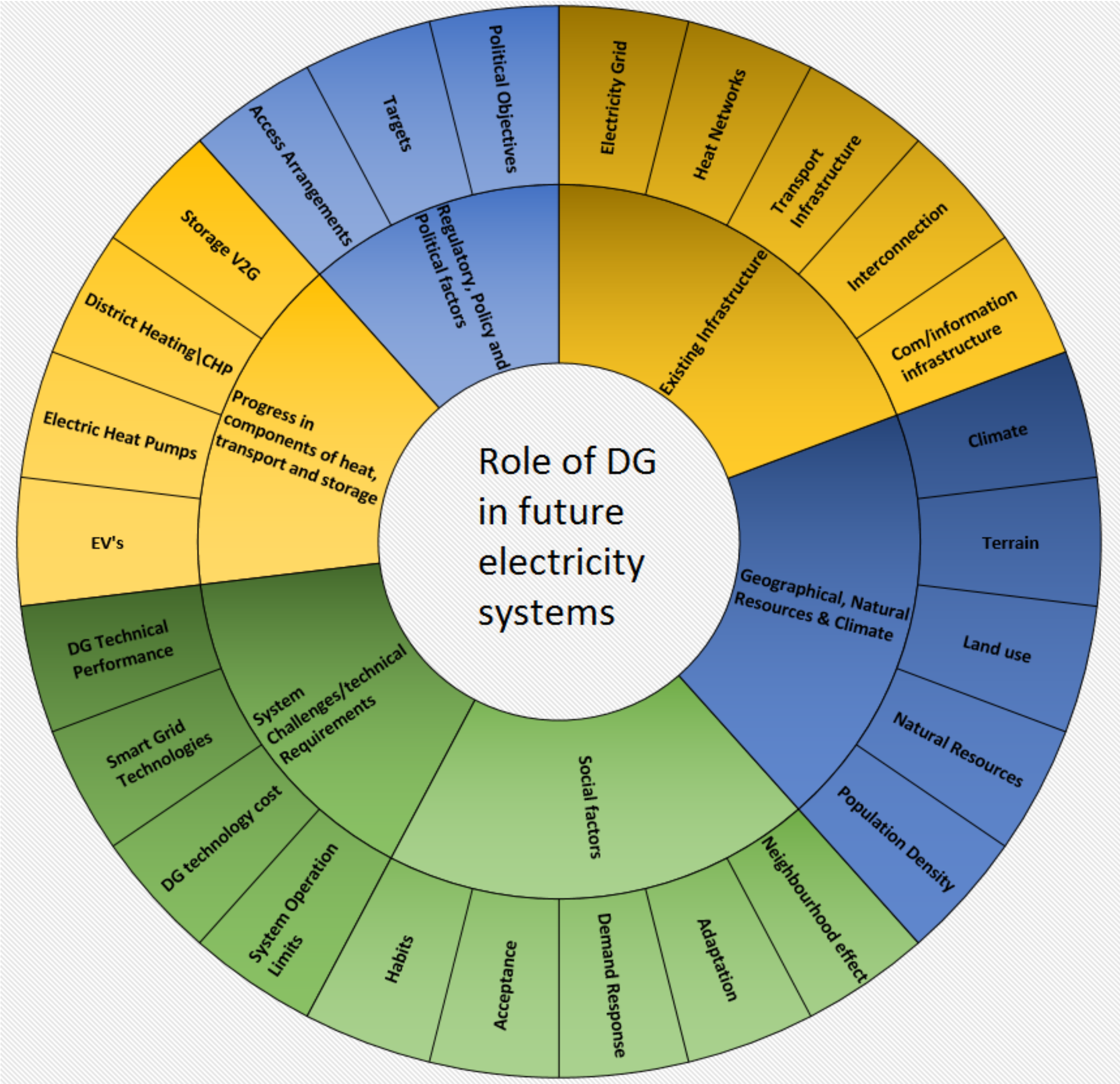


Figure 2-2: A selection of the diverse range of interconnected factors that influence the role of DG in future electricity systems

2.3.1 Geographical, Climatic Considerations and Availability of Natural Resources *(low level of uncertainty)*

The geographical area considered will have significant influence on the future role of DG and the type of DG technology deployed. The climate and terrain will influence the availability and quality of natural resources such as hydro, solar and wind as well as the location of settlements. Proliferation of one particular renewable DG technology type in an area may occur if optimum conditions exist for it. This is the case in Germany, in the North climatic and geographical conditions have encouraged significant wind generation development, while in the sunnier South solar PV is favoured [26].

Population density and distribution as well as existing land use are two other factors that impact the future deployment of DG. The population density and distribution will affect the future electricity demands. In heavily populated urban areas where land is scarce, DG that can be deployed on existing buildings and technologies such as solar PV may be favoured. While in rural areas where land is currently being used for food production there may be a conflict between the land that may be required for energy crops/electricity production and food crops.

The location of natural resources and the relative distance from population centres will dictate the electricity infrastructure requirements for DG deployment.

2.3.2 Existing Infrastructure

(low level of uncertainty)

The existing infrastructure and its reliability will also impact the level of DG deployment. For the situation mentioned under the previous heading where solar generation is prolific in the south of Germany and wind generation in the North, the electricity network must be capable of transferring the power from where it is produced to where it is needed [26].

In countries with unreliable centralised electricity systems, stand-alone DG systems can be more suitable than grid connected ones [24]. Connection to reliable centralised grid infrastructure is still the ultimate goal [74-77] to cater for increased future demand. In countries with more reliable centralised electricity systems and depending on the intermittency of the generation source, distributed generation may be considered a sink or source of power depending on whether it is producing power or not [49]. This makes planning the operation and long-term development of the existing electricity networks more challenging as power flows may be bi-directional.

The ability of an electricity system to integrate DG is also dependent on how well that electricity system is interconnected to other systems. Cross-border connections have been shown to improve the ability of an electricity system to accommodate renewable generation [78], although other researchers have pinpointed complementarity, storage capacity [79] and markets similarities [80] as the key elements for successful interconnection. For example, Denmark has a significant amount of distributed generation (mainly wind generation) with both AC and HVDC interconnections to Sweden, Germany and Norway. Denmark is part of a much larger synchronous electricity system due to the strong AC interconnection with Germany and Sweden. This assists with issues such as inertia, flexibility and resilience to weather fluctuations. The HVDC interconnection with Norway in particular with its complementary hydro resource with large storage helps integrate intermittent DG in Denmark [81] as it effectively acts as a storage mechanism.

Electricity infrastructure is not the only network that needs to be considered, district heating networks, for example, can provide an opportunity for cross-sector efficiencies and thus can result in increased DG deployment.

To maintain the existing supply standards with additional decentralization and electrification, the ability to communicate with many devices is essential. The multitude of disparate devices, range of manufacturers, and cost of equipment and communications require significant investigation into the optimal levels and methods of implementation. Intelligent control of DG is reliant on the availability of telecommunications. Economic considerations will necessitate the use of public infrastructure, namely the Internet. Communications frameworks which are cyber-secure, reliable and scalable are important factors. Moreover, the ability to model and co-simulate (including the use of communications simulation tools) the operation of the communications systems aspects to provide information and insights on issues such a failure of communications or slow performance of communications whether due to high volumes or cyber-attacks is also important.

2.3.3 Technological Change and Progress related to Heat, Transport and Storage *(high level of uncertainty)*

Considering the electricity sector in isolation will not result in a robust evaluation of the role of DG in future energy systems as the electricity sector is only one part of a much larger energy system. Electricity System Operators (SOs) are now considering energy scenarios to understand the range of possible future electricity demands. Within each scenario, changes in the transport and heat sectors such as the uptake of electric vehicles and heat pumps are identified as these could have a significant potential impact on electricity demand and its distribution in the future [82, 83].

Combined Heat and Power (CHP) provides opportunities to avail of cross-sector efficiencies particularly in countries with a pre-existing district heating system. In Denmark, promotion of district heating has been heralded as one of four elements which combined with the other three elements propelled DG penetration to the level it is now: the other three being promotion of CHP, energy efficiency and wind power [84]. However, the cost effectiveness of installing district heating systems is dependent on the population density and climate so it will not be suitable for every location [85].

Installing storage devices in conjunction with DG has been found to improve reliability, reduce generation cost and distribution losses [72]. Thus, the availability of storage or potential storage facilities is another important factor to consider when evaluating the future role of DG in electricity systems. The variability of renewable generation can be mitigated somewhat by electric vehicles (including Vehicle to Grid (V2G)) and electric heating as they can act as storage if controlled or incentivised appropriately. Such technologies are complementary to renewable DG in particular [86] and the changes in these sectors may have a direct impact on the ability of the electricity system to cope with the variability of renewable generation.

Developments in the heat and transport sectors can drive the evolution of the electricity sector in a particular direction. For example, one study identified low carbon centralised systems for electricity and heat as being the best way of meeting increased electricity demand from EVs rather than using distributed micro CHP or district CHP even though the costs are higher [87] as heat driven electricity supply from CHP often lacks concurrency with demand from EVs. Therefore, the interactions between electricity, heat and transport sectors, particularly the optimal levels of electrification in the heat and transport sectors will play a key role in the future of DG deployment.

2.3.4 Social factors and Demand Response

(high level of uncertainty)

Deployment of DERs/DG will depend on social acceptance and consumer behaviour in terms of technology adoption in a region. Social behaviour cannot always be explained by rational economic motives alone and thus cost is not always the deciding factor in uptake of DG. For example, the positive influence of the neighbour effect (i.e., when a neighbour has a DG unit it becomes more desirable) on increasing the uptake of DG is just one aspect of the socio-technical dynamics of decentralised energy systems [51].

Engagement with technology, habits, and the perception that sustainability equates to sacrifice are other social aspects identified as barriers to adopting DG in decentralised energy systems [50]. On the plus side growing public opposition to large electricity infrastructure and generation projects may provide favourable conditions for increased DG deployment in many countries [56, 88-90]. However, opposition to wind generation has also emerged particularly where ownership is not local [64, 91] and thus social acceptance of one DG technology type may be different to other technology types and also depends on whether there is some form of community compensation [92].

The value of demand response to System Operators in times of scarcity has been explored previously [93]. DG certainly has a role to play in providing demand response particularly when employed behind the meter. However, demand response is also subject to social factors as explored by Hobman et al. in [94] which reflects on why so few electricity customers appear to be willing to accept a cost-reflective electricity tariff.

2.3.5 Regulatory, Policy and Political Factors *(high level of uncertainty)*

The regulatory framework in a region will influence the rate and level of deployment of DG. Access arrangements including connection fees and charges and appropriate incentives [63] have been identified as key areas within the regulatory environment to encourage increased DG deployment [55, 84]. Many cite regulatory and legal changes as a requirement to encourage more DG and to realise the vision of the smart grid future [62, 95-100].

Theories such as the 'utility death spiral' are raising concerns about increased DG deployment. This theory suggests that DG in the form of behind the meter generation/private grids results in fewer paying network charges, which increases socialisation costs and more customers opting for self- generation ultimately. The result is reduced network use, spiralling network charges and stranded network assets [101-104]. Such theories highlight the complex nature of the regulatory environment and point to the need for carefully crafted regulatory incentives for system operators and market incentives for developers and ordinary citizens to encourage connection of optimal levels of distributed generation at the most suitable network locations, thereby minimising socialisation costs.

The political vision for energy within the European Union has been clearly set out in the Clean Energy Package with the role of consumers changing from a peripheral role to a central role including easing the way for consumers to produce, store and share energy if they wish to do so [105]. For other regions the future political agenda is not as clear. The political atmosphere within a region influences the regulatory setting and in turn will impact the level of DG deployment that can be achieved. Examples of political and policy targets that could be set include minimising costs, minimising emissions, maximising renewable penetration and reliability of supply. Sometimes these targets may compete with each other. For example, the least cost electricity system may not produce the least emissions. If reliability is prioritised, then DG as part of the localised electricity system may have to be self-sufficient which may make centralisation a cheaper option. The prioritisation of these targets by policy makers and the public will therefore strongly influence the role of DG in future electricity systems.

2.3.6 System Challenges & Technology Requirements

(medium level of uncertainty)

The high initial capital cost of DG technologies has been coming down particularly for wind and solar PV [106] and will continue to decrease with economies of scale which are driven by uptake of these technology types. Uptake is influenced by costs as well as the regulatory environment and social aspects as discussed previously.

Maintaining grid stability during normal and abnormal operation, whilst minimising system costs (both operation costs and long-term investment costs) as DG penetration levels increase is key and “smarter grids” are seen as the enablers to this. However, the cost and maturity level of smart grid technologies are currently perceived as major barriers [107, 108]. Some technologies have already been trialled by a minority of utilities, such as Dynamic Line Rating [109, 110]. Other smart grid technologies are only at concept stage so the rate at which further advancements take place and the time it takes to be rolled out in traditionally conservative utilities will also influence the level of DG penetration. This will have a significant impact on the upper limits of DG penetration, as System Operators will seek to keep DG at levels that the system can be safely and securely operated. This is more likely to restrict generation directly connected to the distribution grid rather than behind the meter generation as utilities have less control over behind the meter generation.

System planning for grid operators will be more challenging with increased levels of DG and other technologies such as EVs, heat pumps, micro-CHP as the seasonal variation in residential (residual) load profiles will be higher [111]. Furthermore, the traditional top-down paradigm no longer holds true so the impact of the transmission and distribution systems on each other can be more pronounced.

A number of technical issues can arise from distributed generation connecting to the distribution network including harmonic distortion, difficulties in voltage regulation and protecting the network [34]. All these issues can be overcome with suitable designs and network integration planning. Thus, setting suitable standards for DG technology prior to connecting such devices to the grid will be essential to mitigate against these issues.

At a system wide level, the technical issues of inertia and levels of operational reserves remain prevalent. In some jurisdictions the level of renewable generation from non-synchronous sources is limited to levels set by the system operator [112]. Non-synchronous resources typically include renewable generation such as wind and solar as well as HVDC interconnectors. Such limits will certainly have an impact on the level of renewable DG deployment unless the inertia lost by replacing conventional centralised transmission generators with low or zero inertia distributed generators is achieved by some other means such as synthetic inertia.

2.3.7 How interacting factors can drive development of an electricity system towards a particular vision

The interactions of each sector of the energy system, the location specific issues (geographical, climatic, social, regulatory), technology costs and challenges and the uncertainties associated with each of these factors all have to be reflected on to fully understand the potential role of DG in the future of electricity systems. These interacting factors will not only influence the level, size and location of DG (and other DER) deployment, they will influence the development of an electricity system towards a particular vision.

For example, geographically isolated areas with rough terrain and relatively low population densities with prolific natural resource availability would lend itself to high DG deployment. A high DG deployment in these isolated areas would naturally lead to the 'fully decentralised' vision described in the Introduction.

On the contrary, heavily populated urban areas with high electricity demand but poor land availability for energy or electricity production may be confined to roof-top DG. Depending on the availability and quality of natural resources as well as roof-top space, a 'centralised with DG' or 'centralised with increased decentralisation' vision may be preferred over the other possibilities.

Understanding the role of DG and other DER in a future electricity system, in addition to understanding what level of DG deployment is appropriate or cost optimal, is essential to determining which vision is most suitable.

2.4 What tool or tools can model how factors influence the role of DG in future electricity systems?

This section describes the "ideal" tool for modelling the role of DG and also explores a small subset of the diverse range of readily available tools that have already or could be used in studies concerning DG.

2.4.1 The "ideal" tool for modelling the role of DG in future electricity systems

The previous section provided an overview of some of the diverse but interrelated factors that can influence the increased penetration of DGs in an electricity system. The ideal tool for modelling the role of DG in future electricity systems considers all the factors discussed in the

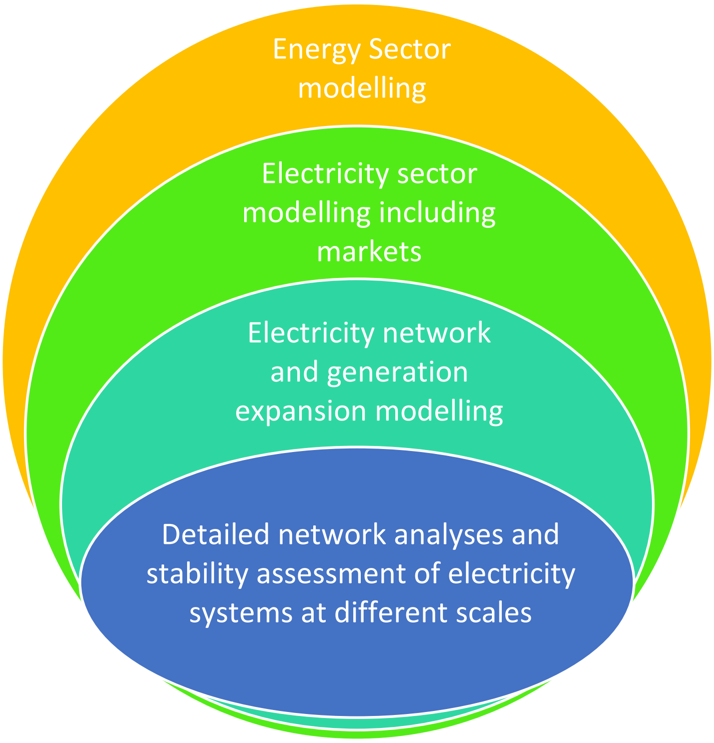


Figure 2-3: A high level overview of the "ideal" modelling tool

previous section and how they interact with each other holistically. It can also model all possible visions for future electricity systems including the four described in the Introduction: (1) centralised with distributed generation, (2) centralised with increased decentralisation, (3) partially decentralised and (4) fully decentralised.

The "ideal" tool (Figure 2-3) has to be multifaceted. It has to incorporate the modelling abilities of an energy sector modelling tool, electricity sector modelling tools including generation and network expansion tools, network analysis tools and market modelling tools. The energy sector modelling part of the tool must be capable of reflecting the geographical, topographical and climatic conditions. It would be used to identify the available and potential natural resources in a region considering any relevant planning policies, the population density spread and the relative location of already existing energy infrastructures. It would also be used to explore the long-term interactions of the heat, electricity and transport sectors including energy storage. The uncertainty of the relevant factors, the social impacts on technology uptake, the cost of technology and its readiness, as well as political and policy targets would have to be reflected in the modelling tool. This energy sector module would be used to develop scenarios for the future energy sector in terms of likely mix of technology types and the demands in each area of the energy sector. The expansion planning aspect of the tool would develop plans and costs for those plans for each energy sector scenario considering detailed network assessments at each stage (such as short circuit, load flow and stability) and assess each vision of the future electricity system. The electricity market modelling aspect would be used to identify market behaviour, which in turn would be used to refine the energy sector modelling further. As indicated in Figure 2-3 each module of the tool would have to interact with all others iteratively refining the output of each module. This ideal tool could be applied to a small region or a vast continent with each aspect considering a relevant time horizon and granularity: Energy sector modelling aspect (long term with hourly granularity), expansion planning aspect (long term with half-hourly granularity), electricity market modelling aspect (short to medium term with 15-minute granularity).

This tool, if it did exist, would be tremendously computationally complex and would require a vast amount of computing power. Developing a tool from scratch can be extremely time intensive and it has been noted in the past that if there is a tool available that can be used to answer a research question it should be used [30]. Nevertheless, in spite of strong progress in computational speed and model development, many studies face challenges in obtaining high quality data to populate models. There are a number of international movements[1] aiming to address this issue but access to good quality data is a barrier to model development in many parts of the world.

The following subsections explore some of the tools that are already available.

[1] For example see www.openmod-intiative.org and https://energydata.info/.

2.4.2 Models for Investment Appraisal of Centralised Generation versus Decentralised Distributed Generation

Studies which consider the optimal way to provide electricity within a region can be split into greenfield studies and brownfield studies. Greenfield studies are those focused on areas that currently have no electric grid infrastructure whereas brownfield studies are undertaken on areas that have an existing electricity grid infrastructure. Greenfield locations include developing countries or geographically remote locations and are generally more straightforward than brownfield studies as there are no legacy grid or generation issues to contend with.

The general methodology followed for greenfield studies considering investment appraisal involves a geographical survey to identify the potential of natural resources and distance from centralised electricity grid, calculation of demand requirements considering current and future population densities (usually via bottom up approach), identification of how the centralised grid could be extended to provide the most coverage, calculation of levelised cost of electricity for off grid, minigrid and grid connected options. Several factors identified in the previous section of this paper are regularly considered in greenfield studies such as: population density, geographical data, renewable resource potential [76, 113, 114], and land availability [113] as well as technology costs of conventional and renewable systems [76, 113, 114].

The tools used for greenfield studies in a number of the papers reviewed were custom built. Muselli et al. presented a geographical information system (GIS) modified with economic tools to identify the most appropriate mix and management of energy in rural locations in South Corsica [113]. Nassen et al. used a Life Cycle Cost (LCC) model to decide between centralized electricity provision or decentralised solar home systems/mini-grids for providing electricity in rural Northern Ghana [114]. Flores et al., also used a GIS system, but in this case it fed into a model which identified the least cost electricity mix to meet demand for the rural residential sector in Honduras. A bottom-up approach was taken to estimate the electricity consumption per household per year and the various options were compared using the Levelised Cost of Electricity (LCOE) [76]. Very high levels of detail are required about the end uses of electricity being produced for the approach considered by Hiremath et al. in [115]. In that paper, WinQSB is used to solve the goal programming problem of meeting multiple objective functions for various scenarios including minimising costs, emissions and maximising efficiency, employment and use of local resources.

Levins and Thomas presented a method for choosing between decentralised and centralised electricity supply for previously un-electrified areas in [77]. A weighted composite Prims algorithm is used where the population at each node is used for the weighting. The result of the two phase algorithm is a minimum spanning tree which represents the optimal expansion of the centralised network. The LCOE of the centralised network versus the decentralised option are then compared to determine which is optimal for a number of countries. This approach is solely focused on electrification and considerations associated with more mature grids such as reliability and resilience are not taken into account within the methodology although they are discussed within the paper.

For areas without an existing electricity supply, researchers agree that for low population densities, low demand and depending on the distance to the centralised grid, decentralised electricity systems are more economically viable than centralised grids [74-76, 106, 114]. The benefits of lower upfront capital costs and the ability to increase the capacity in blocks as required are identified as the main reasons for considering decentralised electricity systems as a means to provide electricity in these areas [74]. However, most researchers agree that even if decentralised electricity systems are the least cost option the ultimate goal is still to connect to a reliable centralised grid [74-77, 114]. These tools are not capturing longer-term goals beyond electrification such as demand growth that may follow initial electrification. Such tools identify whether the 'fully decentralised' vision is a better option than any of the other three in the first instance to achieving electrification. These tools are useful for a first phase analysis where the sole political and policy objective is to achieve electrification at the cheapest cost. However, given the inherent uncertainty in any forward-looking modelling exercise, tools and frameworks that are technology agnostic, scalable and adaptable may provide richer insights into the diverse pathways of an uncertain future by generating understanding of complementary or competing technologies. Table 2-1 summarises the main strengths and weaknesses of the investment appraisal models discussed here.

References/Tools	Strengths		Weaknesses
	Useful for greenfield sites where sole target is electrification	considers terrain	Does not consider optimality after electrification is achieved so limited use for brownfield sites
[74]	✓		✓
[76]	✓		✓
[77]	✓		✓
[113]	✓	✓	✓
[114]	✓		✓

Table 2-1: Main strengths and weaknesses of investment appraisal models

2.4.3 Energy Sector Modelling Tools

There is a vast range of well-established energy system models that focus on one or more sectors within the energy system (transport, electricity, heat). Energy sector modelling tools provide insights into the interactions of electricity, heat and transport. Reviews of available energy system models have been carried out previously [30, 31, 116] which highlighted the vast array of models available: bottom-up, top-down, simulation, optimisation, equilibrium and so on.

Scenario analysis is often used to explore the effect of policies, targets, or constraints. Such models are not intended to provide a single result but rather to generate insights. Therefore, they are usually not used to provide a single answer but to provide a range of answers for a set of scenarios, which help to understand cause-and-effect relations. The outputs of such models are highly dependent on the quality of the inputs and the parameters set within the model. As the uptake of DG/demand response/cost reflective tariffs may not always be predicted on the basis of rationality, behavioural economics has a significant role to play in understanding likely behaviours. Energy sector modelling tools should have a way to reflect the findings of behavioural economics studies. In an effort to set the standard for energy sector optimisation modelling, DeCarolis et al. recently provided best practice guidelines on the use of energy system optimisation models [117] which discusses the use of hurdle rates as one such way to reflect behaviours in technology adoption.

As previous reviews of energy and electricity sector modelling tools have provided classifications and categorisations for similar tools [31, 118], we will limit the scope of our review to identifying studies already carried out using these tools that have added to the knowledge base and how these tools may be used in the future to further explore the role of DG in electricity systems.

2.4.3.1 MESSAGE (Model for Energy Supply Strategy Alternatives and their General Environmental Impact)

MESSAGE is a modelling framework within which there are a number of models targeted at differing objectives [119]. MESSAGE-Access is a model which considers residential energy access as part of the overall MESSAGE global energy system model. It has been used in a greenfield study to explore the role of decentralised distributed generation in South Asia [120]. Similar to the models for investment appraisal discussed previously, it was found that decentralised DG is a lower cost solution than centralised supply for areas previously without electricity. Rather than focus on the cost of energy supplied it focuses on the cost of energy delivered. In terms of exploring the future role of DG a study using MESSAGE-Access could provide valuable initial results for a greenfield region.

2.4.3.2 OSeMOSYS (The Open Source Energy Modelling System)

Details on the structure, development and subsequent enhancements of OSeMOSYS can be found in [16, 121]. Elements of smart grids such as demand shifting and storage have also been added to the original OSeMOSYS code as outlined in [122]. No peer-reviewed literatures specifically relating to OSeMOSYS and DG were discovered in this literature search however the scope for expanding the code has already been demonstrated and therefore with additional coding the tool could prove beneficial in exploring the role of DG in future energy systems.

2.4.3.3 TIMES (The Integrated MARKAL-EFOM System)

TIMES is a model generator developed by IEA-ETSAP; it is a tool which integrates engineering and economic approaches to energy modelling to explore possible future energy pathways [123]. TIMES has already been used for modelling DG within the European energy sector [124, 125] and many TIMES models are available for individual countries. A study focusing on DG and storage in a small region using TIMES has also been presented in the literature [126], therefore TIMES could prove extremely useful in exploring long term future scenarios of distributed generation in electricity systems. However, TIMES is limited in its ability to capture higher temporal resolution and accurately model load flow even with the TIMES Grid add on [127]. The scenario results from TIMES could be used in conjunction with electricity sector modelling tools to identify short and medium term network constraints which in turn could be used to refine the TIMES model inputs further. This would essentially overcome the limitation of TIMES in respect of load flow modelling. Soft-linking or coupling of models is discussed in more detail later on.

2.4.3.4 ENERGYPlan

EnergyPlan models the electricity, heat and transport sectors of national energy sectors. Unlike other energy sector models, it generally runs for only one year. However, multiple runs for different years can be used to build up a scenario. The impact of DG on the transmission network is often neglected in the literature but the impact on grid losses and congestion has been previously explored with EnergyPlan combined with another tool EnergyGRID Pro in [88]. EnergyPlan has been used at city, regional and country level. It is not possible to model multiple countries in EnergyPlan without the use of an Add-on tool 'Multinode' which can model cross-border interconnectivity albeit in a very limited way [128]. For the purpose of modelling the role of DG in future electricity systems, due to the limitations in the manner cross-border interconnections can be modelled, EnergyPlan could be useful up to country level only.

2.4.3.5 TEMOA (Tool for Energy Model Optimisation and Analysis)

TEMOA is an open source energy system optimisation model. The motivation for its development was twofold: to provide a tool that could be verified by others and a tool that could cope with the complex uncertainties required for long term energy sector modelling [129]. Of particular interest to the question of the role of DG in future electricity systems is the uncertainty associated with a number of factors. TEMOA has been used in conjunction with an optimisation method known as 'Modelling to Generate Alternatives' (MGA) [130]. Energy sector modelling tools are programmed to provide optimal solutions; however, these optimal solutions may not be most realistic. MGA can be used to explore near optimal solutions which may produce different outcomes to the optimal solution. This can be used to identify where a factor is marginal. As discussed in section 2.3 there is significant uncertainty surrounding the factors that impact the future role of DG and there may also be competing policy and political targets to contend with. Using a methodology such as MGA would provide valuable insights into how the various factors can impact the role of DG in future electricity sectors.

2.4.3.6 How Energy System modelling can inform the future role of DG?

Energy sector modelling tools provide useful long-term outlooks into how the electricity, heat and transport sectors interact and can provide an indication of electricity demand due to changes in other sectors. This electricity demand could be used by more detailed electricity system models to further refine the inputs of energy sector modelling tools. Renewable energy deployment at high levels have already been explored using energy sector modelling tools. These tools can also be used to explore how the role of DG changes with different levels of predefined decarbonisation levels or emissions limits. DG technologies can and have been included as technology types available at different voltage levels but benefits such as avoiding network investment if optimally sized and located are not currently captured in energy sector modelling tools as these tools do not generally consider the existing grid infrastructure in detail. Energy sector modelling tools alone will not provide sufficient insight into the future role of DG in an electricity system but when used in conjunction with other tools could prove extremely effective. Table 2-2 summarises the main strengths and weaknesses of the energy sector modelling tools discussed here.

References/Tools	Strengths			Weaknesses	
	explores interactions of electricity, heat & transport	considers long term targets and objectives	includes technology costs and some social factors	does not intrinsically capture the electrical characteristics and limitations of the electricity grid (load flow, voltage, stability, inertia etc)	is dependent on other tools to identify limitations of electricity grid to use as input constraints
Message	✓	✓	✓	✓	✓
Access [119]	✓	✓	✓	✓	✓
OseMoSYS [121]	✓	✓	✓	✓	✓
TIMES [123]	✓	✓	✓	✓	✓
EnergyPlan	✓	✓	✓	✓	✓
TEMOA [129]	✓	✓	✓	✓	✓

Table 2-2: Main strengths and weaknesses of energy sector modelling tools

2.4.4 Electricity System Modelling Tools

Electricity System modelling tools include generation economic dispatch and unit commitment tools, generation and network expansion tools as well as network analysis tools for load flow, dynamics and stability assessment. Depending on the tool, it may look at a short, medium, or long-term horizon. For example, some generation and network expansion tools look at snapshots from the load duration curve (LDC) rather than considering the entire chronological sequence. This reduces the computational complexity but has also been shown to yield inaccurate results [131].

2.4.4.1 PLEXOS® Integrated Energy Model

PLEXOS® Integrated Energy Modelling software originated as a power market modelling software but has since expanded its capabilities to include modelling of integrated electricity, gas, water, heat and their transportation systems. PLEXOS can model the technical and economic aspects of generation in a power system, including optimal load flow and losses at transmission level, for generation economic dispatch and unit commitment considering constraints. It can also be used for centralised capacity expansion planning using load duration curves or chronological simulation [18]. PLEXOS has previously been used to study the future role of DG from an economic perspective but in conjunction with an energy sector modelling tool and the impacts of DG on the distribution system were not considered [60]. PLEXOS has already been used to model a 'centralised with DG' vision and it could also be used to model 'centralised with increased decentralisation' and 'partially decentralised' visions although it would not be able to model the underlying networks in detail.

2.4.4.2 WASP (Wien Automatic System Planner)

WASP is a medium to long term generation expansion planning software. Kalampalikas and Pilavachi used WASP to explore various scenarios for the future Greek electricity system which included solar and wind but a stochastic representation of the intermittency of the resources was absent [132, 133]. Voumvoulakis et al. consider intermittent renewables as a negative load and perform hourly simulations to develop monthly load duration curves factoring in the negative contribution of renewables to the load [134]. The previously mentioned studies highlight the limitations of WASP in its ability to capture the intermittency of renewable generation and hence it does not present as useful a tool as PLEXOS in exploring the role of DG in future electricity systems. WASP is a traditional centralised planning tool for centralised systems. Unless further releases of WASP improve on its ability to handle intermittency it would not be appropriate for modelling any of the visions of future electricity systems including DG.

2.4.4.3 Tools for the Distribution Network

Bearing in mind the significant technical issues and impacts that DG can have on the distribution network it is not surprising that it has garnered a lot of attention in the literature. The EU directive requiring Distribution System Operators to consider using demand side management or DG as an alternative to network upgrades or replacement has also resulted in a growth of interest in the area [135]. Georgilakis and Hatziargyriou [136], Singh and Sharma [57], Jain et al. [70], Pesaron et al. [73], Ehsan and Yang [137] and Abdmouleh et al. [138] have all conducted literature reviews on the topic of distribution system planning with DG. Georgilakis and Hatziargyriou found that renewable DG and its impact on distribution line losses has not been properly addressed, nor has the combination of renewable DG and storage been explored in terms of line losses and optimal placement. Singh and Sharma suggest that different techniques are suited to different objective functions. Pesaron et al. conclude that using a hybrid optimisation tool is the most suitable approach when renewable DG is factored into the problem. Jain et al. deduces that the optimal approach to distribution system planning depends on the inevitable trade-offs between "accuracy, reliability, computational efforts, and time." Both Ehsan and Yang and Abdmouleh et al. identify the need for incorporating uncertainty into distribution system planning with DG.

Goop et al. conducted a study that examines the potential of increased DG, specifically solar and wind, to alter power flows between voltage levels and to reduce losses in the distribution system. It considers active power only and uses mixed integer linear programming with an objective function of minimising total operating costs. The results of the study indicate that the benefits of the DG considered are only reaped if demand and the DG is at the same voltage level as generation. The study is limited by the assumptions made which include that conventional generation is only connected at high voltage (HV), CHP and wind at medium voltage (MV) and solar at low voltage (LV) and the assumption that generation is first consumed at the voltage it is produced [47]. Given that distribution networks particularly at lower voltages are radial in nature this assumption may be an oversimplification. However, it does stand to reason that generation connected close to load will incur less losses and thus reduce system transport costs.

Bin Humayd and Bhattacharya [139] presented a framework for optimal distribution system planning incorporating DG placement, optimal demand response levels and controllable and uncontrollable loads (Electric Vehicles). It assumes that DG is dispatchable and does not consider behind the meter generation. For a 39-bus test system the run time was in excess of 3 hours, for a larger network the computational time could be a deterrent.

One critique of many of the distribution system planning tools in the literature is that they fail to take into account the interactions of the transmission and distribution networks. Kiani Rad and Morevej provide one example of a co-ordinated planning approach by developing a network expansion tool for transmission and distribution (to MV level only) which considers DG location and capacity to avoid investment in network. When applied to the data from a real regional power system the authors found that the co-ordinated planning approach led to more optimal results and incorporating DG improved the results even further [66]. The computational time reported is an average of 10 minutes but it is not clear to what number of buses this relates. The DG units are modelled as constant negative loads which fails to take account of the intermittent nature renewable DG and it does not consider behind the meter generation.

In spite of the large volume of literature in the area of distribution system planning considering DG, there is no tool that considers all types of DG units (including renewable DG and its stochastic nature and behind the meter (BTM) generation), storage and that also considers the interactions with the transmission system as well as the avoided costs of network expansion achieved by optimal DG placement and sizing. In terms of modelling the future visions of electricity systems, these tools provide limited insight as they focus predominantly on a centralised vision of the distribution network.

2.4.4.4 Network and Stability Analysis Tools

Due to the potential problems that arise due to integration of DG in networks such as harmonics, voltage issues and load flow congestion, it is necessary to study the impacts of DG in detail to identify the upper limits of penetration. Network and stability analysis tools are used to understand the problems introduced by increased DG penetration and also to develop solutions. In addition, these tools can be used to evaluate any potential benefits that DG can bring to networks such as avoided network development or upgrades and reduced losses. Many tools to consider network and stability aspects of integrating DG exist. Some tools such as GridLAB-D [140] and OpenDSS [141] are open source and have been used extensively in researching smart grids at distribution level and are useful for examining small ‘fully decentralised’ electricity systems. Commercial tools such as Siemens PTI PSS® software tools focus on transmission systems [142], while DIgSILENT PowerFactory can be used for industrial, low, medium or high voltages [143]. Some of these tools consider a snapshot of the network and these can be used to develop constraints in terms of size and positioning of DG that could be used by other tools such as PLEXOS.

2.4.4.5 How Electricity System modelling tools can inform the future role of DG?

Electricity system modelling tools are essential to understanding the role of DG in future electricity systems and consequently the future development of electricity systems. Generation and network expansion tools yield insights into the likely development of electricity networks and generation portfolios in the future. While mature off-the-shelf tools exist for generation and transmission network expansion, there are no comparable off-the-shelf tools at distribution level considering DG. A considerable body of research exists on distribution system planning and it continues to be an actively researched area as the electricity system changes from being a top-down unidirectional power flow paradigm to a bidirectional power flow paradigm. Some of the tools presented in the most recent research may prove useful if developed further. Network and stability analysis tools can be used to understand and develop solutions for network issues such as network congestion and harmonics. There is no one electricity system modelling tool that can perform generation and network expansion, economic generation dispatch, optimal power flow and network and stability analysis for the entire electricity network (i.e., transmission, distribution and behind the meter) and considering the future visions of the electricity system. Even if such a comprehensive tool did exist, it would not reveal the true role of DG in future electricity systems as it fails to account for the interaction of the electricity sector with other energy sectors. Table 2-3 summarises the main strengths and weaknesses of the electricity system modelling tools in relation to the role of DG in future electricity systems. This not intended to be an exhaustive list and the software may have applications outside of this domain, readers are encouraged to browse software homepages and references for full view of applications and uses.

References/ Tools	Strengths										Weaknesses									
	useful for transmission capacity expansion	useful for generation capacity expansion	calculates dispatch costs and long-term expansion costs	useful for exploring impact of players market strategies on price of electricity	can identify limitations of electrical grid	can validate feasibility of proposed expansion plans from electrical point of view	useful for investigating DG sizing and placement within distribution network	includes behind-the-meter generation	considers interactions of electricity & heat	includes demand response	considers DC load flow only	does not intrinsically capture the electrical characteristics and limitations of the electricity grid (voltage, stability, inertia etc)	is dependent on other tools to identify limitations of electricity grid (e.g., reserve/inertia requirements)	can identify limitations for load flow and harmonics only	does not model interactions of heat, transport, and electricity	does not include any electrical modelling of grid	DG modelled as negative constant load	System wide issues such as inertia and flexibility are not considered	considers electrical losses as estimated percentage	does not intrinsically capture the electrical characteristics and limitations of the electricity grid (load flow, voltage, stability, inertia etc.)
PLEXOS [144]	✓	✓	✓	✓							✓	✓	✓							
WASP		✓	✓									✓	✓							
Grid LAB-D [140]				✓	✓	✓								✓	✓					
OpenDSS [141]					✓	✓	✓								✓					
Siemens PTI PSS [142]					✓	✓									✓					
DIgSILENT [143]					✓	✓									✓					
[47]							✓									✓		✓		
[66]							✓										✓	✓		
[139]							✓									✓		✓		
[67]								✓	✓	✓									✓	✓

Table 2-3: Main strengths and weaknesses of electricity modelling tools

2.4.5 Studies considering the whole electricity system and behind the meter distributed generation

This literature search revealed one recently published study (2017) [67] which considers efficiency of centralised versus distributed generation from a more holistic electricity system point of view. The study presented a mixed integer linear programming model with an objective function to minimise total system costs. It is used to explore the factors (including some thermal factors) that influence the optimal mix of distributed and centralised generation. It considered a number of scenarios based on a case study of Spain that included demand response capabilities, heat pumps and an access fee to recover stranded costs due to self-consumption. The results were significantly caveated due to concerns over the input data but the author maintained that the qualitative results stood. The optimisation model presented is a good first step to addressing the gap in the models available however there are some limitations that would need to be overcome so that the model could properly assess the role of DG in future electricity systems. For example: network investment costs and network losses associated with centralised generation would have to be more accurately reflected rather than represented by a percentage; solar PV, heat pumps and batteries would have to be widely available not just at residential level; the input on demand would also need consider the interactions of transport and other aspects of heat and the behavioural economics element on technology adoption that some energy sector modelling tools provide would also have to be included. This study focused primarily on a 'centralised with DG' vision of the future electricity system.

2.4.6 Soft-linked models

Soft-linking or model coupling[2] is transfer of information from different models in a way that leverages the strengths of a particular model to enhance overall understanding of the system. The motivation is derived from a view that one specific tool cannot address all aspects of the full energy system in great detail and greater insights and progress can be gained by drawing on the strengths of multiple modelling tools rather than trying to incorporate them all into one comprehensive model. Soft-linking overcomes "*the limitations of using a single all-encompassing tool*" [145]. Researchers have previously used soft-linking to marry the benefits of tools to provide more accurate results and additional insights [16, 146, 147] and also to explore the differences between top-down and bottom-up energy sector models [148]. In a

2 Soft-linking is also known as model coupling or co-simulation.

review of generation expansion tools Oree et al. acknowledged that soft-linking was a "*rational strategy*" to overcome the computational complexity of a generation expansion problem with a long time horizon and a high temporal resolution [17]. While it was not referred to as soft-linking of models, Lilley et al. used a combination of an Energy Sector tool and a PLEXOS model of the Australian electricity market to explore the role of DG in Australia from an economic perspective. The study did not capture the influence of and on the distribution network but it did capture the interactions of different sectors within the energy sector by the use of an energy sector model to identify possible future generation mixes [60]. Expanding such a framework to include the distribution network and elements of behind the meter generation via soft-linking of tools could be used to explore the role of DG in future electricity systems.

2.5 Discussion

The factors that influence the role of DG in future electricity sectors

In this paper, the main categories of factors that influence the role of DG were presented:

- Geographical & Climatic Considerations and Availability of Resources
- Existing infrastructure, incl. information and communications technology
- Technological Change and Progress related to Heat, Transport and Storage
- Social Factors and Demand Response
- Regulatory, Policy and Political Factors
- System Challenges & Technology Requirements

The impact of each factor will vary depending on the region or area being considered. The factors discussed in the first two categories listed above have been attributed a low level of uncertainty as these factors are either already fixed or are unlikely to change significantly. The factors presented in the category of System Challenges & Technology Requirements have been assigned a medium level of uncertainty as these are a less certain and depend heavily on other factors. How quickly technology costs fall will be influenced by the demand for the technologies as well as advancements in the technology itself. In addition, in regions where System Operators have placed limits on the amount of non-synchronous generation, deployment of energy storage will have an impact in addition to advancements of technology for replacing inertia. The remaining categories of factors have been attributed a high level of uncertainty as how these factors will change in the future is very difficult to project.

One of the challenges of the myriad of factors that may influence the future role of DG is that factors with higher uncertainty levels can impact factors with lower uncertainty levels. For example, Regulatory, Policy and Political Factors will play a part on whether the available natural resources can and will be fully utilised. Therefore, it is essential to be able to model, not just one category of factors but to model the interaction between the factors and how it can shape the future role of DG in electricity systems and ultimately shape development of an electricity system for an area or region towards one of the four visions: 'centralised with DG', 'centralised with increased decentralisation', 'partially decentralised' and 'fully decentralised'.

2.5.1 The challenges of modelling DG

The research question of what will the future role of DG in electricity systems be is a complex one due to the broad range of interrelated factors that influence DG deployment and the uncertainty surrounding those factors. Capturing all these factors within one tool would prove challenging if it is even possible.

This literature review has revealed that there is no one tool that can model all the relevant factors and their impacts on the energy and electricity sector to answer the research question of what is the future role of DG in electricity systems considering the possible visions of future electricity systems. The time it takes to develop new tools and the computational complexity of an all-inclusive tool makes soft-linking of a number of different tools and models to answer this research question a good option. Different tools looking at the same research question from different perspectives can yield interesting insights and using soft-linking can provide a rich answer. Soft-linking of tools and models is not without its pitfalls. Consistency and plausibility checks are crucial and convergence of results can become very challenging and highly iterative when using soft-linking. It requires careful combination and setting of parameters and an understanding of how each model works to make it truly effective.

2.6 Conclusion & Future Research

The main categories of factors that impact the role of DG in future electricity systems and the level of uncertainty associated with each category have been presented in this paper. The challenge when trying to model the impact of these factors is that they interact strongly with each other. Understanding the interactions of these factors is key to understanding what the role of DG may be in the future, which in turn reveals which vision is most likely for a particular electricity system.

The ideal tool is one that can model the interactions of all the factors on all facets of the electricity system in the context of the wider energy system comparing all future visions. It is clear from this review that no one tool will provide an overall view of the role of DG in future electricity systems and if one did exist it is likely to be computationally complex. There are tools that already exist that can provide insights into how some factors may impact the role of DG within the electricity system such as energy sector and electricity sector modelling tools. Soft-linking is a method that could be adopted to harness the insights these tools can provide on these factors and reflect the interrelated nature of both factors and the various aspects of each sector.

Future research will focus on exploring options for determining the optimum mix of centralised and decentralised electricity for a region using soft-linking or specific-purpose extensions of existing tools.

Chapter 3: Renewables in the European power system and the impact on system rotational inertia

3.1 Abstract

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.

3.2 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 [8, 149]. 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[3]. 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

[3] 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.

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. 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 [150, 151].

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) [152] and Great Britain (GB) [153]. Another investigation utilised historical system data following disturbance events to tune the parameters of a dynamic model for the Nordic region [154]. 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 [155]. 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 [156, 157]. 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 [158]. 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 [159]. 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 [160]. 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 0.75Hz/s [161]. 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 (0.5Hz/s and 1Hz/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 (CO_2) 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 3.3, the context and the progress made to date in addressing the inertia challenge is reviewed/summarised for Europe. In section 3.4, the methodology adopted, and assumptions used for carrying out the studies are described. In section 3.6, the results are presented and analysed, followed by a discussion and conclusion in section 3.7.

3.3 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.

3.3.1 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 [162]. 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 constant, H_{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 [150]. Using equation (1) the inertia constant of the system, measured in seconds (s), can be calculated as follows:

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

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.

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

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 is shown in Table 3-4 [163]. 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 [154].

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 [164]. 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 [154]. This is likely to become even more challenging as consumers and prosumers assume a more active role within the electricity market [165].

3.3.2 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) [166].

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

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% [167] making it the "*first in the world to reach this level*" [168]. There are plans to increase this by 5% each year to a maximum of 75% by 2020 [169]. Monitoring this metric alone is not sufficient to maintain stability so a minimum inertia requirement of 23,000MWs at all times is also in force in Ireland [167].

3.3.3 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 [151].

Provision of FFR from different technology types is discussed in depth by Karbouj *et al.* [170]. 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.* [171] 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 [171]. 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 [172], although the recently concluded RESERVE project demonstrates that this is an active area of research [173-175]. 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 [172]. 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 [13]. In GB energy storage has been introduced [176]. 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 [177], MIGRATE [178] and EU-SysFlex [179] to find workable solutions.

3.3.4 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 [180]. 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 [181].

Table 3-1 below shows which synchronous areas in Europe require minimum inertia levels currently as indicated by their representatives to ENTSOE [182, 183]. 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 [184].

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

Table 3-1: Status of Minimum Inertia Level Requirement at present

3.4 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.* [158], 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.

3.4.1 Pan European Model

A pan-European electricity dispatch test system with hourly resolution developed in an Integrated Energy Model (IEM) for previous works [19, 161] in PLEXOS ® Simulation Software [18] 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 [185] similar to some of the other studies [19, 161]. The objective function is set to minimise 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 [19]. The optimization problem, in the form of a mixed integer linear programme (MILP), is solved for each hour of a 24-hour rolling horizon with a 6-hour 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 3-2.

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 hour
Horizon	24 hour + 6 hour look ahead
Software Version	PLEXOS 7.500 R05
Solver	Xpress-MP[4]
CPU Type	Intel(R) Core(TM) i5-6300U CPU @ 2.40GHz

Table 3-2: Overview of main objective function and optimization software

3.4.2 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 [186]. The IEM model inputs of hourly electricity demand, installed generation capacity mix, and fuel and CO_2 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 3-3.

Scenario	**1**	**2**
Basis	**ENTSOE Vision 1**	**ENTSOE Vision 4**
Electricity Demand (TWh)	3,434	3,616

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

Variable Renewable Capacity (GW)	388	614
Fuel Prices (€/GJ):		
Natural Gas	9.5	7.2
Oil	17.3	13.3
Coal	3.0	2.2
CO_2 Prices (€/Tonne)	17	76
Merit Order	Coal before gas	Gas before coal

Table 3-3: Comparison of ENTSOE visions

As illustrated in Figure 3-1 Vision 1 '*Slowest Progress'* and Vision 4 '*European Green Revolution'* contrast in terms of decarbonisation ambition [185]. 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.

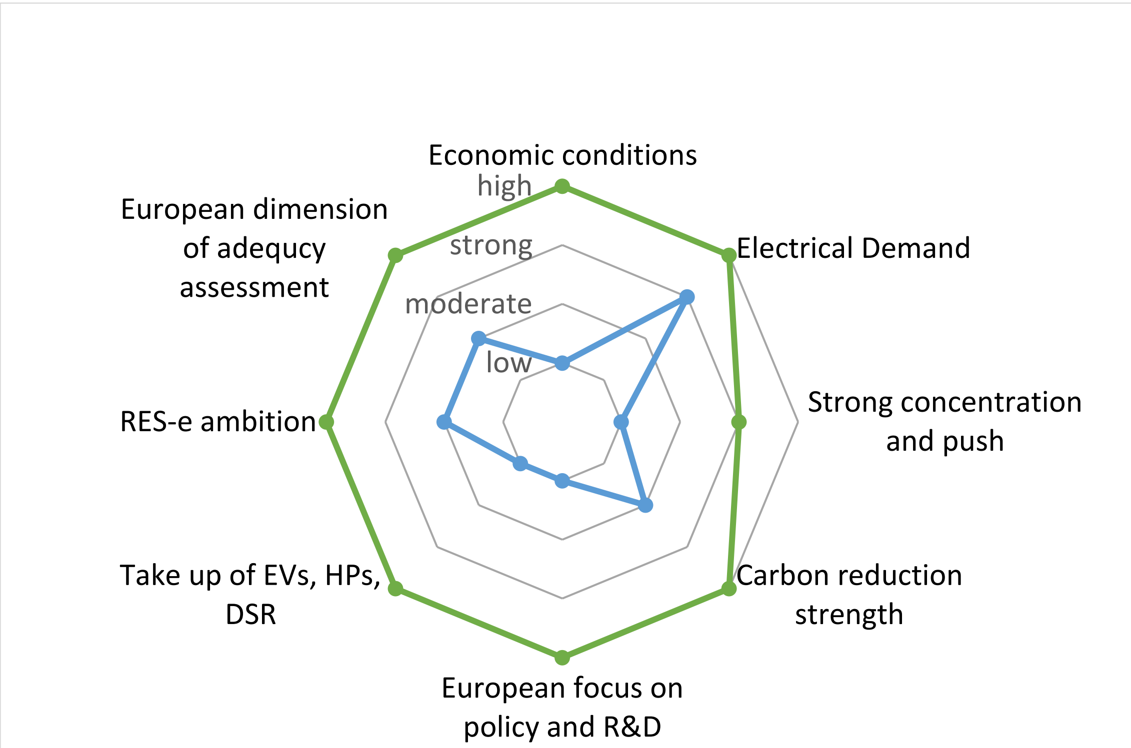


Figure 3-1: Overview of the characteristics of the relevant two ENTSO-E Visions as interpreted from [41]

3.4.3 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 [187] 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 [188]. 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.

3.4.4 Generator characteristics

The main generator characteristics used are detailed in Table 3-4, which are based on standard generator characteristics used in previous studies [19, 161]. Each generator type was assigned a particular value for its stored rotational energy (MWs) [163].

Fuel Type	Capacity (MW)	Start Cost (€/Start)	Minimum Stable Factor[5] (%)	Stored Rotational Energy (MWs)
Biomass-waste fired	300	10,000	30	1,220
Biogas fired	150	12,000	40	610
Geothermal	70	3,000	40	0
Hydropower, lakes	150	0	10	700
Hydropower, run of river	200	0	10	820
Natural gas CCGT	450	80,000	40	3,200
Natural gas OCGT	100	10,000	20	240
Nuclear energy	1,200	120,000	50	5,800
Oil fired	400	75,000	40	900
Solids fired	300	80,000	30	1,600

Table 3-4: Main Generator Characteristics

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

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

3.4.5 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 0.5Hz/s and 1Hz/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 3000MW representing the loss of the two largest nuclear power units within the same power station that can cascade trip for a frequency disturbance [189]. 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 3-5.

	Largest Infeed (MW)	**Assigned minimum inertia for ROCOF limit of 1Hz/s (MWs)**	**Assigned minimum inertia for ROCOF limit of 0.5Hz/s (MWs)**
CE	3,000	75,000	150,000
Nordic	1,400	35,000	70,000
GB	2,000	50,000	100,000
Baltic	700	17,500	35,000
Ireland	700	17,500	35,000

Table 3-5: Largest Infeed and assigned minimum inertia levels

As can be seen in Table 3-5 a ROCOF tolerance of 1Hz/s halves the required level of system inertia to offset the largest infeed compared to a ROCOF tolerance of 0.5Hz/s. The selection of 0.5Hz/s and 1Hz/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 1Hz/s by late 2017 [169], but this is not implemented yet [167].

3.4.6 Assumptions made in the analysis

This study is not intended to replace dynamic studies, rather this 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.* [190]. 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.

3.5 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 effect. 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 [158]. Furthermore, the provision of ancillary services that may reduce minimum inertia requirements has not been considered in the study.

3.6 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 optimisation problem, as the CO_2 price is included in the calculation of total generation costs.

3.6.1 Simulations without an inertia constraint applied

In Figure 3-2 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 0.5Hz/s and 1Hz/s as per Table 3-5. 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.

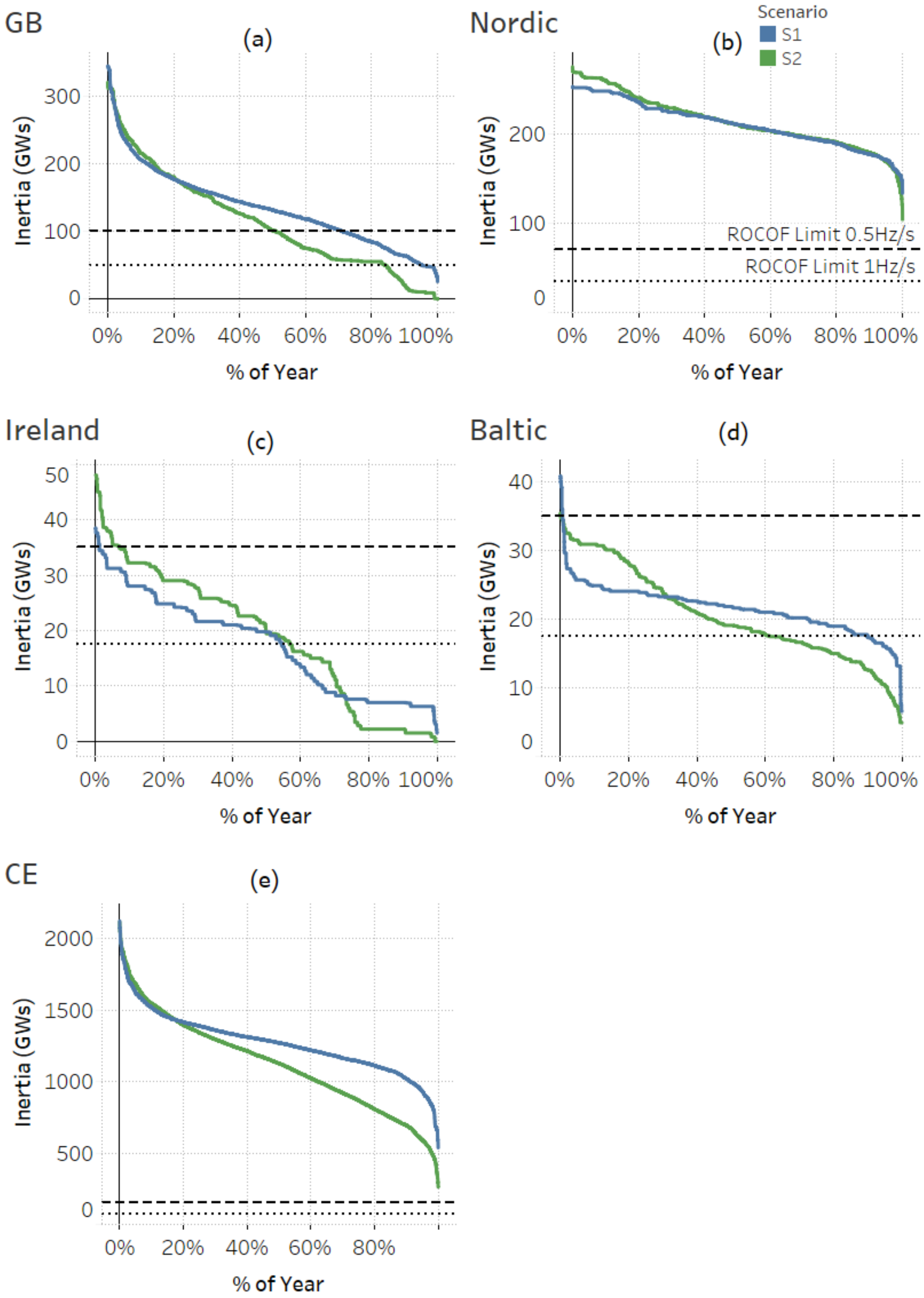


Figure 3-2: Inertia duration curves for all synchronous grids with no ROCOF limit

The model uses perfect foresight and focuses on minimizing 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 Figure 3-2 (a) to (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 Figure 3-3 (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 3-5.

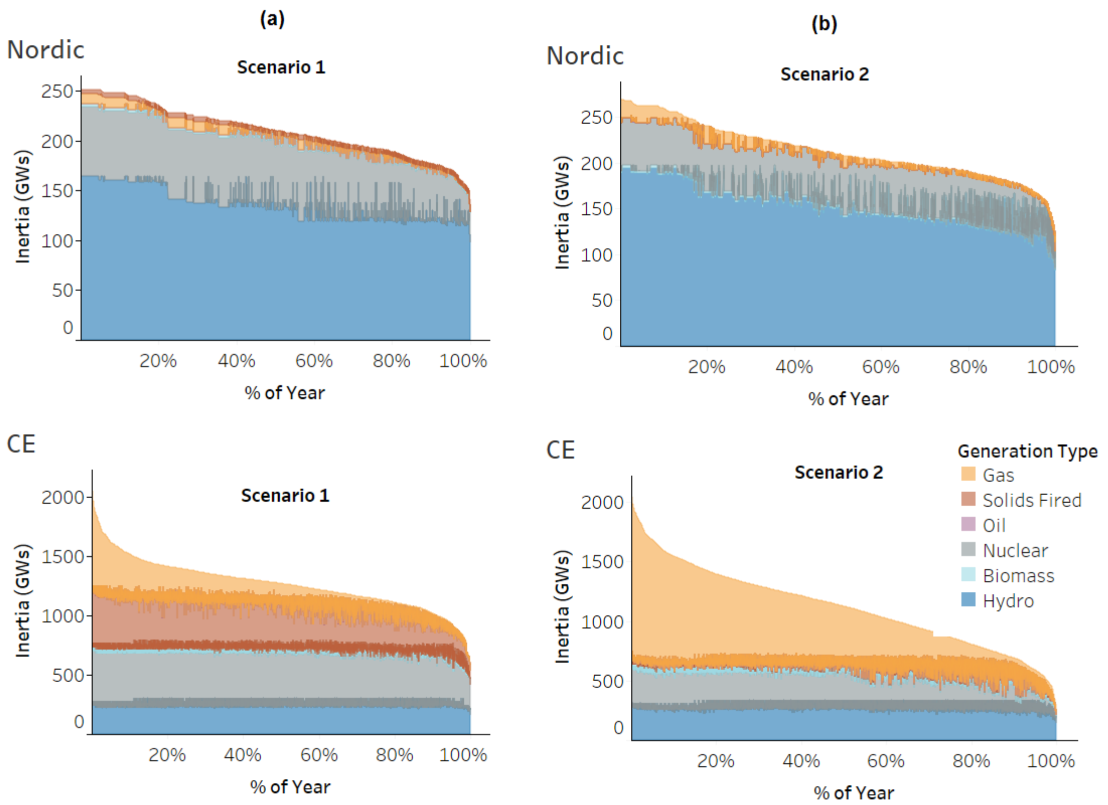


Figure 3-3:Inertia contribution by generation type for the Nordic and CE synchronous areas for (a) Scenario 1 and (b) Scenario 2 with no ROCOF Limit

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 3-4 due to the change in dispatch to meet the constraints in the other synchronous areas.

3.6.2 Simulations with inertia constraints to limit ROCOF

The changes in interchange between synchronous areas, total generation costs, VRE curtailment and CO_2 emissions relative to the base case that result from applying the constraints are presented in Table 3-6 and Figure 3-4 for Scenario 1 and Table 3-7 and Figure 3-5 for Scenario 2.

	Total generation cost		**VRE Curtailment**		**CO_2 Emissions**	
ROCOF Constraint	**1Hz/s**	**0.5Hz/s**	**1Hz/s**	**0.5Hz/s**	**1Hz/s**	**0.5Hz/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 3-6: Change relative to base case for Scenario 1

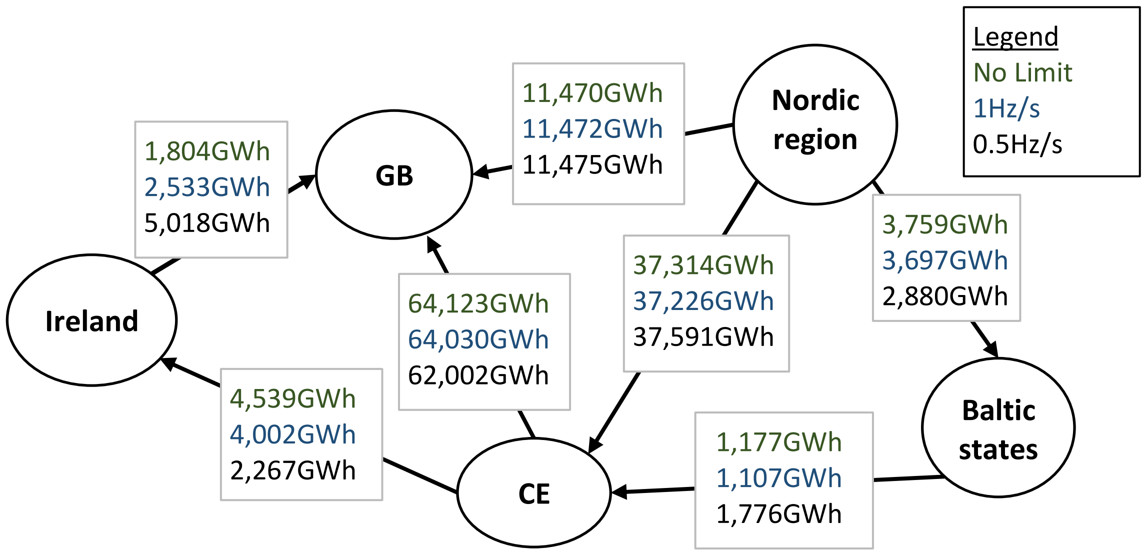


Figure 3-4: Net interchange between synchronous areas for each ROCOF level in Scenario 1

	Total Generation cost		VRE Curtailment		CO_2 Emissions	
ROCOF Constraint	1Hz/s	0.5Hz/s	1Hz/s	0.5Hz/s	1Hz/s	0.5Hz/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%

Table 3-7: Percentage change relative to base case in Scenario 2

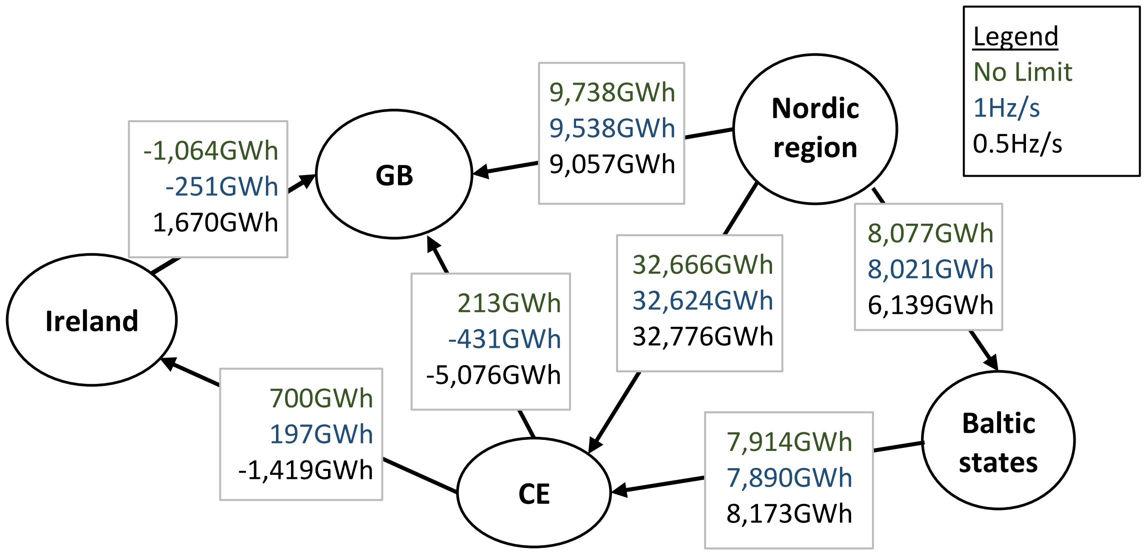


Figure 3-5: Net interchange between synchronous areas for each ROCOF level in Scenario 2

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 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 3-4). 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 CO_2 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 affect 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 (Figure 3-6).

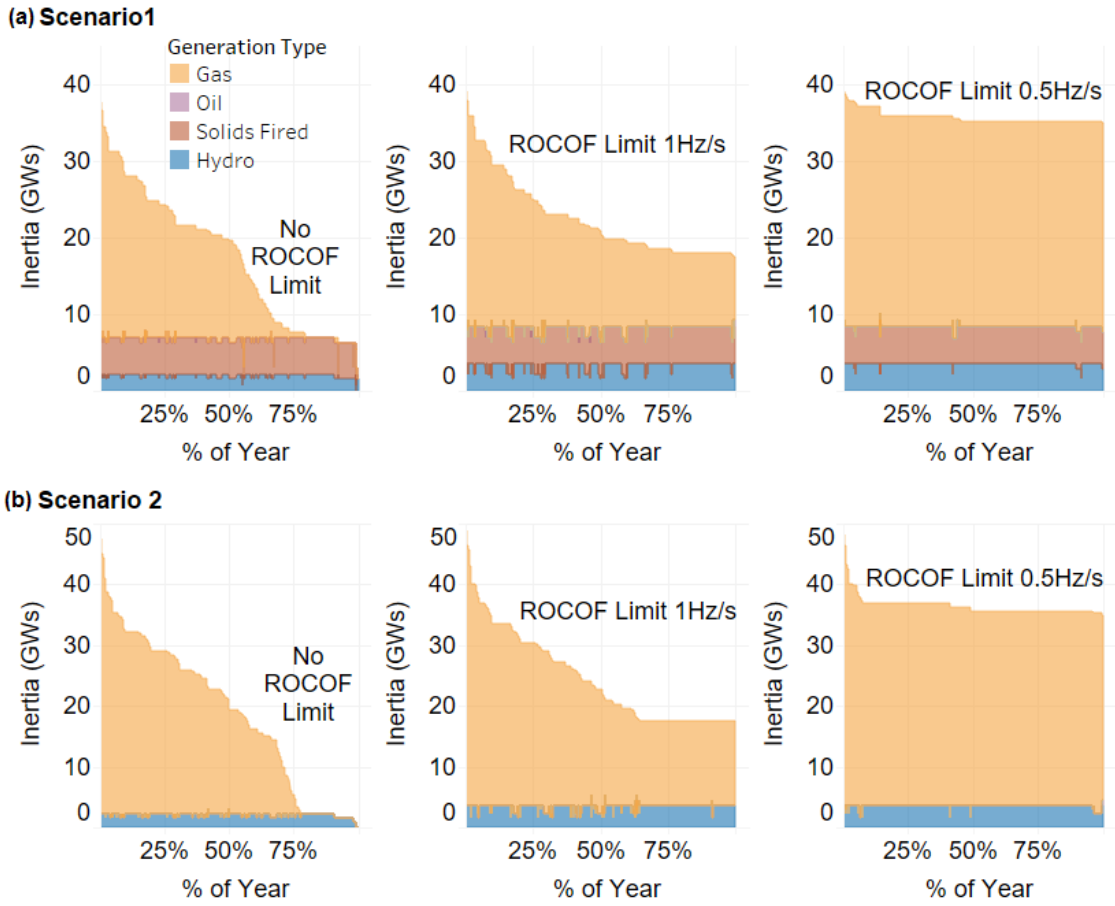


Figure 3-6: Hourly Inertia contribution by generation types for Ireland for (a) Scenario 1 and (b) Scenario 2 ranked by total inertia as a percentage of year

The suggestions of EirGrid [12] and Cuffe et al. [191] hold true for Ireland in this study as total generation costs, VRE curtailment and CO_2 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 CO_2 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 CO_2 emissions increase in GB also but only for Scenario 2 the more heavily decarbonised scenario (Table 3-7). 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 Figure 3-4, 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 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 Figure 3-6 and Figure 3-7. 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.

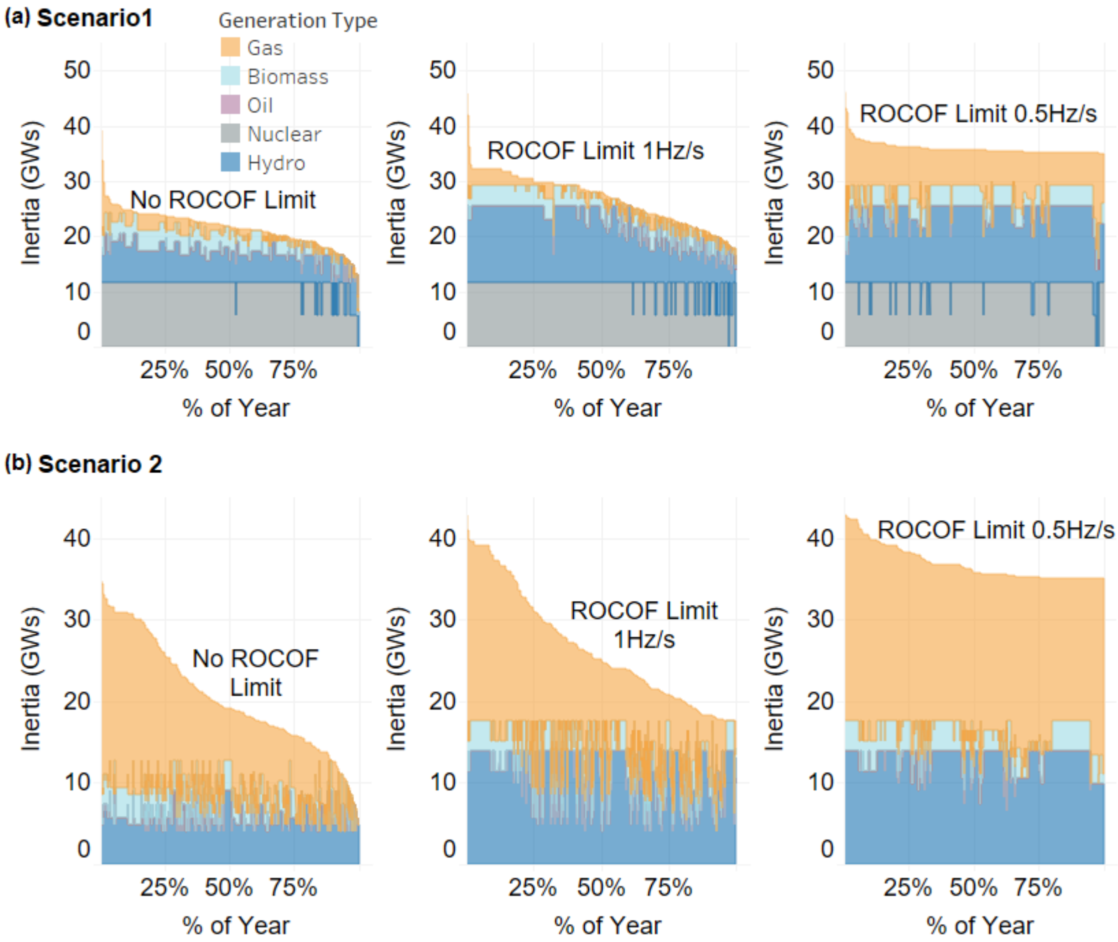


Figure 3-7: Hourly Inertia contribution by generation types for Baltic area for (a) Scenario 1 and (b) Scenario 2 ranked by total inertia as a percentage of year

The practical and grid code limits for ROCOF in the various synchronous areas in Europe vary from 0.25Hz/s [192] up to 2.5Hz/s [193]. This study focused on the levels currently set and proposed in Ireland. Increasing the minimum inertia requirement to meet a ROCOF level of 0.5Hz/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 0.5Hz/s limit to a 1Hz/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.

3.6.3 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 1Hz/s and 0.5Hz/s for the loss of 3000MW of generation for the year 2030. Delving into the results on a per-country level (Table 3-8) reveals that sufficient inertia at synchronous area level does not guarantee that sufficient inertia is maintained at a per-country basis at all times.

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

Table 3-8: Minimum, maximum and average hourly inertia values in the CE synchronous area

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 3-4). 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 0.5Hz/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 3-8 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. Figure 3-8 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 0.5Hz/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 52GWs and Spain, Portugal, Italy, Denmark, and Germany provide zero inertia.

An obvious area to focus on based on Figure 3-8 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 [194], 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.

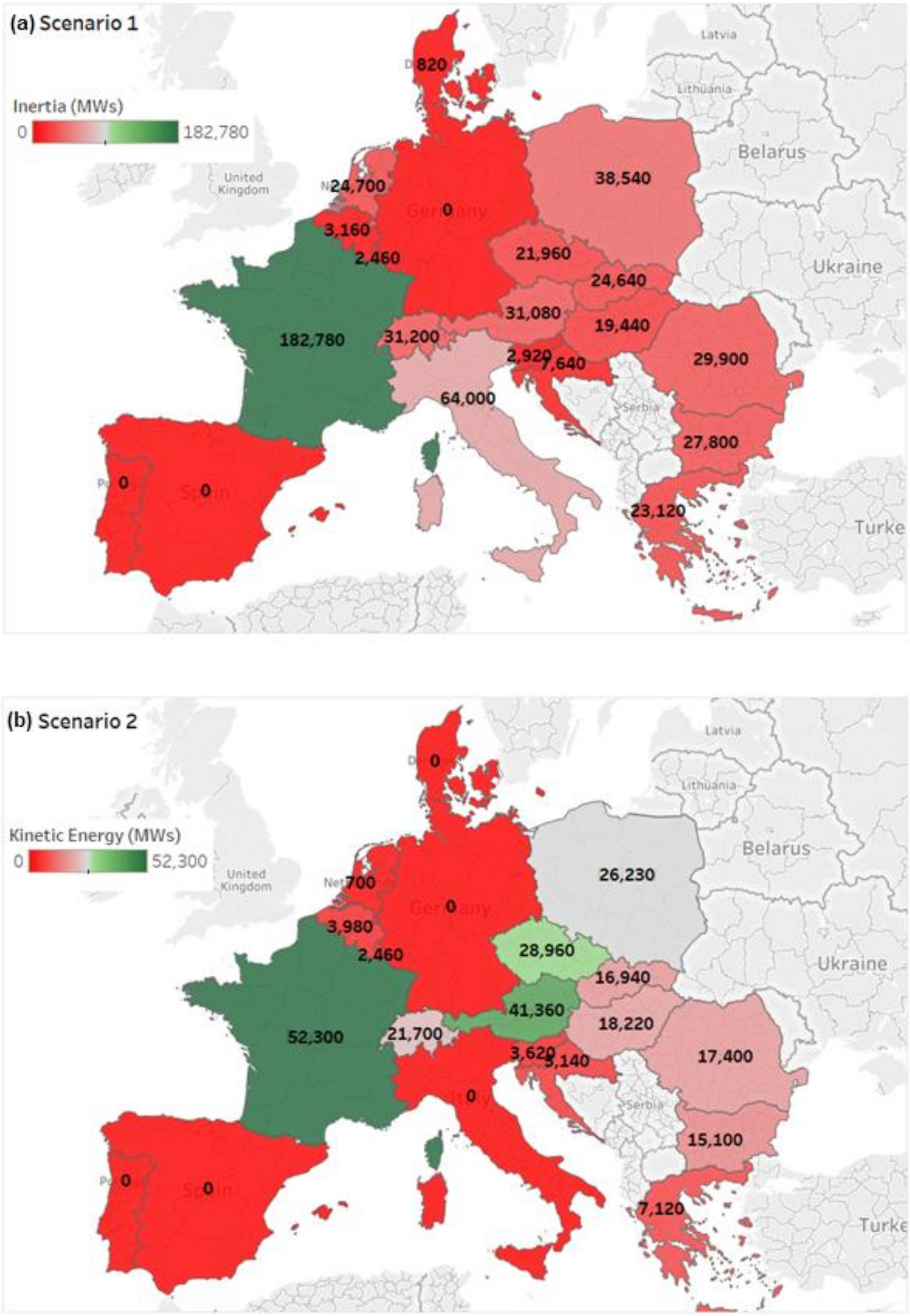


Figure 3-8: Contribution per country at lowest hourly inertia across CE for (a) Scenario 1 and (b) Scenario 2

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 CO_2 emissions reductions it is essential that the TSO utilize 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 [158], explicit payments for ramping [195], balancing [196], primary frequency response [197], fast frequency response [198, 199] 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 [200] but it is too early yet to determine how effective it will be.

3.7 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 decarbonization scenarios for two ROCOF limits. The analyses found that the impact of minimum inertia levels was unique to each synchronous area depending on size, generation capacity mix, and interchange with neighbouring synchronous areas. This study 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.

3.8 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.

Chapter 4: Batteries and interconnection: competing or complementary roles in the decarbonisation of the European power system?

4.1 Abstract

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 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 2.4TWh for the basecase, but a high carbon price is critical to ensuring their deployment reduces 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.

4.2 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 [7]. 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 [201, 202].

Increased electrification met by carbon free electricity presents an opportunity to reduce emissions [203] 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 [8]. Generation from RES in the European electricity sector has increased from 16% of final electricity consumption in 2005 to 34% in 2019 [204] and is likely to continue to increase significantly [205]. Nevertheless, highly emissive fossil fuels will still feature in the generation mix in 2030 albeit to a smaller extent (typically ~5% generation) [206-208]. 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 [209], Romania in 2032 [210], 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 [179, 211]. This additional flexibility could be provided by interconnection to other power systems which shifts electrical power geographically [212]. 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 electricity mix in 2050 [213]. 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 [10].

Researchers have observed that increased decentralisation is an inevitable component of the energy transition [214, 215]. 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 [216]. With increasing renewables penetration driving decentralisation and a push towards centralisation through increased interconnection between countries and electrically islanded systems [5], 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 Network Operators of Electricity (ENTSOE) in the latest Ten-Year Network Development Plan (TYNDP) [21]. 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 4.3, a literature review is presented highlighting the contributions of this work. The data and methods used in the study are described in Section 4.4. In section 4.7, the results are presented and discussed, followed by a conclusion in section 4.8 and future work in section 4.9.

4.3 Literature Review

The history of cross-border interconnection in Europe goes back to the 1920s [217]. 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 [218]. In addition to providing system security benefits by leveraging diverse generation portfolios and demand, interconnection offers the opportunity to increase the integration of renewables, share reserves between the interconnected parties and lower overall system investment and operating costs [219]. However, projects may take many years if not decades to develop for a variety of reasons including public opposition [220].

Batteries have a long history yet the use of grid-scale batteries in electricity systems is a more recent development [221]. Suitably located batteries can defer network investments by managing network congestion. In addition to assisting in energy balancing, batteries can provide system services such as blackstart capability, frequency regulation and flexible ramping [221] 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 [222].

The significance of examining the impact of storage on emissions [223] and the impact of storage on emissions depending on the generation mix have been demonstrated [224] 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 [225] however storage is not a feature of the study.

Studies have previously considered interconnection and storage as part of expansion planning seeking to find the optimum mix of technologies for future years [213]. Knezovic *et al.* presented an expansion study on a '*reduced representative'* pan European system and concluded interconnection is most economic option for integrating large amounts of VRE sources (VRES) [226]. Taking the larger geographic area of Europe, the Middle East, and North Africa, Bussar *et al.* examined how different technology mixes and constraints impact the least cost 100% renewable electricity system for 2050. The authors highlighted how constraints on cross-border interconnection capacity or long duration storage can significantly increase costs [227]. Steinke *et al*. determined the optimal level of storage to minimize backup energy requirements for a 100% renewable European electricity system [228]. While Child *et al.* 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 [229]. These studies are useful for policy makers to identify the ideal mix of renewables and storage technologies and grid expansion in the future. However, 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 [230]. Furthermore, for 2030, coal phase out across Europe will not be complete. Thus, comparing interconnection and storage on a like for like basis for a scenario that still features fossil fuels as is presented in this paper adds to the body of knowledge.

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 [231]. Utilising curtailed energy and minimising the amount of curtailment is an active area of research. Researchers have investigated using curtailed energy for hydrogen production [232], off-grid applications [233] , reducing emissions associated with EV charging [234], mitigating curtailment by shifting load between data centres [235]. 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 [236] and can assist in reducing VRE curtailment [218]. 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 [237]. 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 focusing on the impact on one technology or total VRE curtailment. Also of note is the inclusion of coal in the generation mix of the base scenario for 2030 as per stated policy.

4.4 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.

4.4.1 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*" [238]. 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 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.

4.5 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* [18]. 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 [21]. Electric heat and smart charging are modelled implicitly as the impact of temperature and smart charging are endogenous in the ENTSOE electricity demand profiles.

In this work each country is represented as a single node as shown in Figure 4-1. 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.

Figure 4-1: Map of interconnection in model

The objective function within the model seeks to minimise the total 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-hour 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 4-1. 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 [145, 239]. 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).

Generator Type	Capacity (MW)	Start Cost (€/Start)	Minimum Stable Factor[6] (%)
Biofuel	300	10,000	30
Natural gas CCGT	450	80,000	40
Natural gas OCGT	100	10,000	20
Hydropower	200	0	10
Nuclear	1,200	120,000	50
Lignite	300	80,000	30
Hard Coal	300	80,000	30
Oil	400	75,000	40
Other NonRES	300	5,000	30

Table 4-1: Standard Generator Characteristics

The normalised wind and solar profiles used in this analysis were based on historical data available in ENTSOE Pan European Climate Database [240]. For hydro-generation, country specific monthly capacity factors based on average historical outputs available from ENTSOE Transparency Platform were used [241]. The fuel prices used were taken from the ENTSOE 2020 TYNDP [242] and are shown in Table 4-2 below.

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

Table 4-2: Fuel prices used in the analysis

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

As the operation of behind the meter batteries are often optimised to minimise the consumers' costs rather than the system costs, for this study only grid scale centralised batteries are modelled. Battery characteristics are standardised with a typical maximum power of 100MW, a 3-hour duration, and an efficiency of 90%. 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.

4.6 Model Simulations

All model simulations were performed on a Dell Intel(R) Core (TM) i5-6300U CPU @ 2.40GHz. 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 4-3. 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 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 percent increase in wind and solar capacity and (3) a high carbon price combined with a 10 percent 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. The high carbon price selected for this study was €100/tCO_2 while the standard price is as per the Global Ambition scenario data at €35/tCO_2.

<table>
<tr><th>Simulation</th><th>Difference from Basecase</th><th>Sensitivity 1</th><th>Sensitivity 2</th><th>Sensitivity 3</th></tr>
<tr><td>Basecase</td><td>-</td><td rowspan="7">High CO_2 Price</td><td rowspan="7">Plus 10 % VRES (wind and solar) capacity</td><td rowspan="7">High CO_2 Price plus 10 % VRES (wind and solar) capacity</td></tr>
<tr><td>Interconnector 5% (IC5)</td><td>IC capacity increased by 5% system demand peak per country</td></tr>
<tr><td>Interconnector 10% (IC10)</td><td>IC capacity increased by 10% system demand peak per country</td></tr>
<tr><td>Interconnector 10% (IC15)</td><td>IC capacity increased by 15% system demand peak per country</td></tr>
<tr><td>Battery 5% (Bat5)</td><td>Battery capacity increased by 5% system demand peak per country</td></tr>
<tr><td>Battery 10% (Bat10)</td><td>Battery capacity increased by 10% system demand peak per country</td></tr>
<tr><td>Battery 15% (Bat15)</td><td>Battery capacity increased by 15% system demand peak per country</td></tr>
</table>

Table 4-3: Overview of simulations and sensitivites carried out

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.

4.7 Results & Analysis

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.

4.7.1 Basecase and impact of sensitivities

The sensitivities show the impact of changing aspects of the basecase including the carbon price, an increased variable renewable portfolio, and a combination thereof. The high carbon 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 carbon price and 10% additional VRES capacity, production from solids fuelled generation reduces significantly with an increase in production from gas (Figure 4-2).

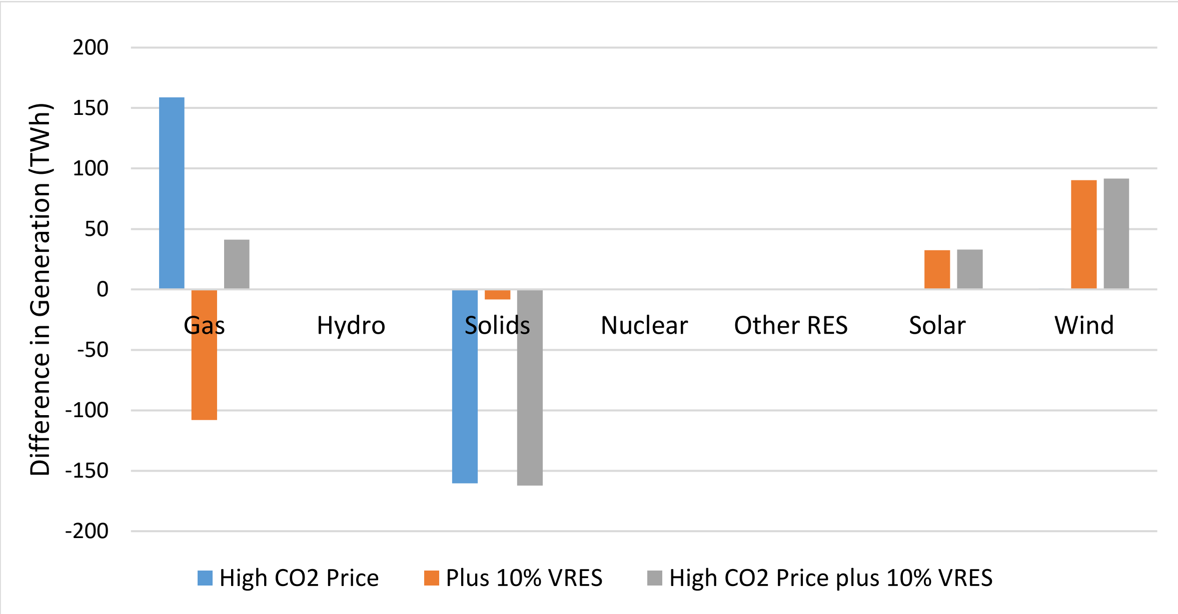


Figure 4-2: Difference in production by fuel type compared to basecase for each sensitivity

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 Figure 4-3. 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 carbon 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 carbon price in addition to increased VRES capacity mitigates this increase by 30.5%.

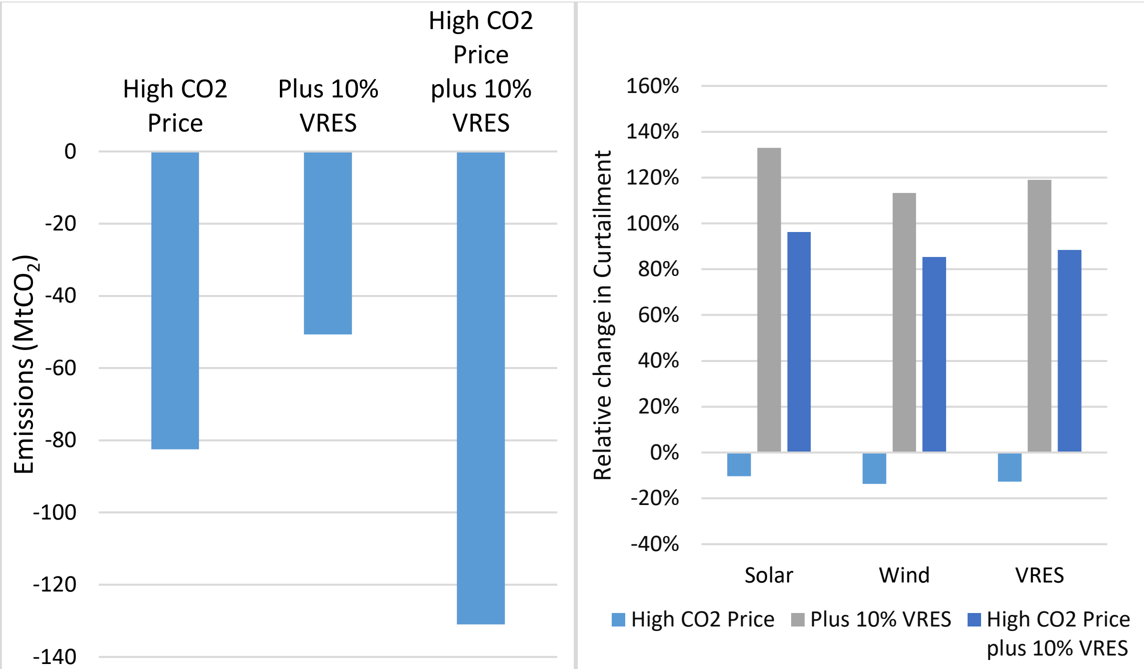


Figure 4-3: Change in emissions and relative change in curtailment for the sensitivities relative to the base scenario

This analysis of the results confirms that for power systems with fossil fuel fired generation, a high carbon price will reduce emissions and VRE curtailment. It is worth noting, however, that a high carbon price without the correct market design is unlikely to lead to a decarbonised reliable electricity system [230].

4.7.2 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.

Figure 4-4: Difference in emissions compared to the relative basecase

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 Figure 4-4 (Sensitivity = None) shows that increasing interconnection may increase emissions slightly. This reflects the fact that increased interconnection facilitates increased production from cheaper but higher emitting solid fuelled generators (Figure 4-5).

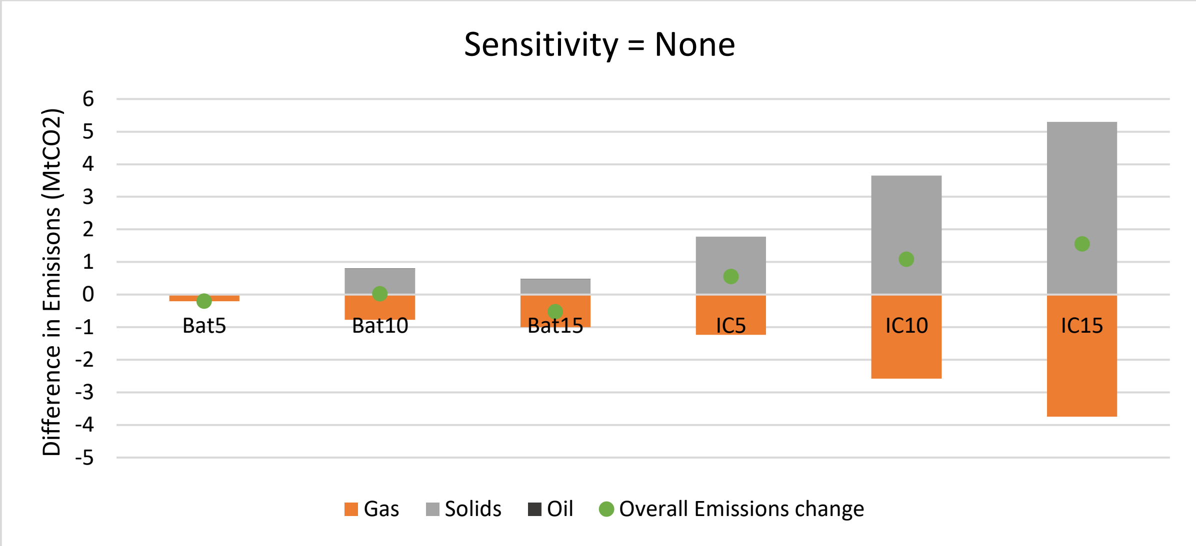


Figure 4-5: Difference in emissions production by fuel type and overall emissions for scenarios with Sensitivity = None compared to basecase

For both high carbon 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 carbon price both technologies reduce emissions across the modelled European power system with interconnection outperforming batteries on a megawatt for megawatt capacity basis (Figure 4-4 and Figure 4-6). Given that the study increases capacity of these technologies by percentage of demand by country, it is reasonable to assume that optimal placement and sizing would lead to even greater emissions reductions.

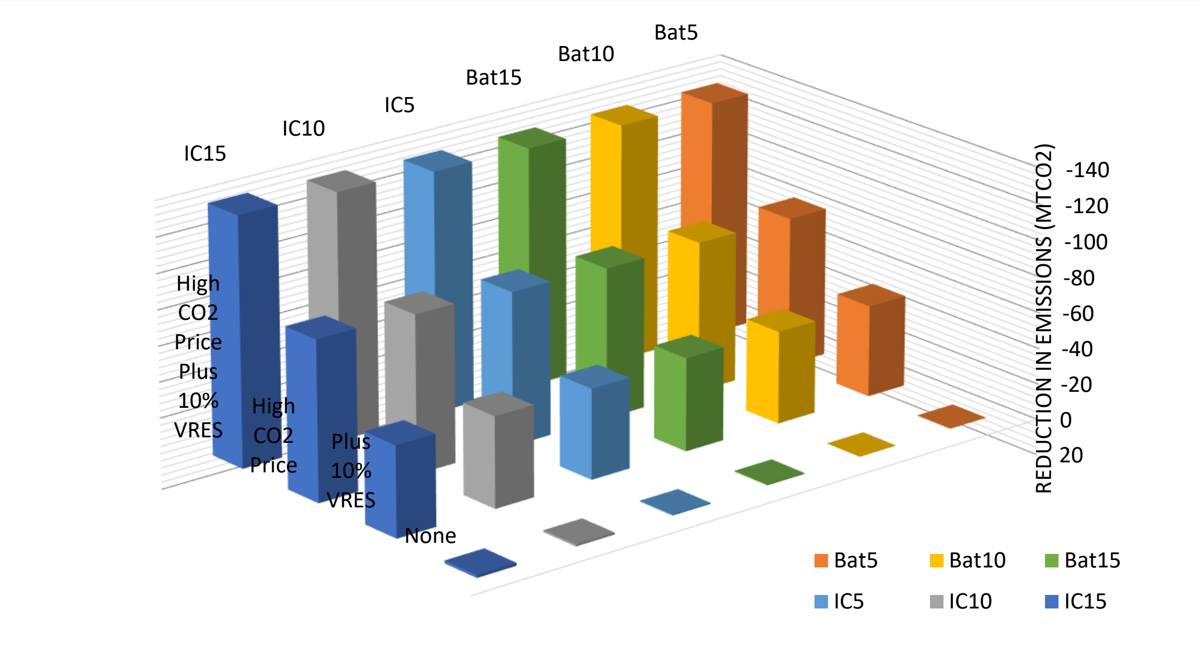


Figure 4-6: Reduction in emissions by scenario for all sensitivities compared to base case with no sensitivity

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 CO_2 Price Plus 10% VRES’) (Figure 4-4 and Figure 4-6). 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 (Figure 4-4 Sensitivity = None, (Bat5, Bat10 and Bat15)) and increasing interconnection capacity for the ‘Plus 10% VRES’ sensitivity (Figure 4-4, 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 carbon price. For both sensitivities (‘None’ and ‘Plus 10% VRES’) the carbon price was at the lower level of €35/tCO_2. This coupled with the fossil fuel prices adopted in the study (Table 4-2) results in production and consequently emissions flipflopping between coal and gas as necessary to achieve the least cost dispatch. The highest increase in emissions for these situations relative to their basecase is 0.25MtCO_2 (Figure 4-7), 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 carbon price is not sufficiently high to guarantee that the outcome of their deployment is to cut emissions.

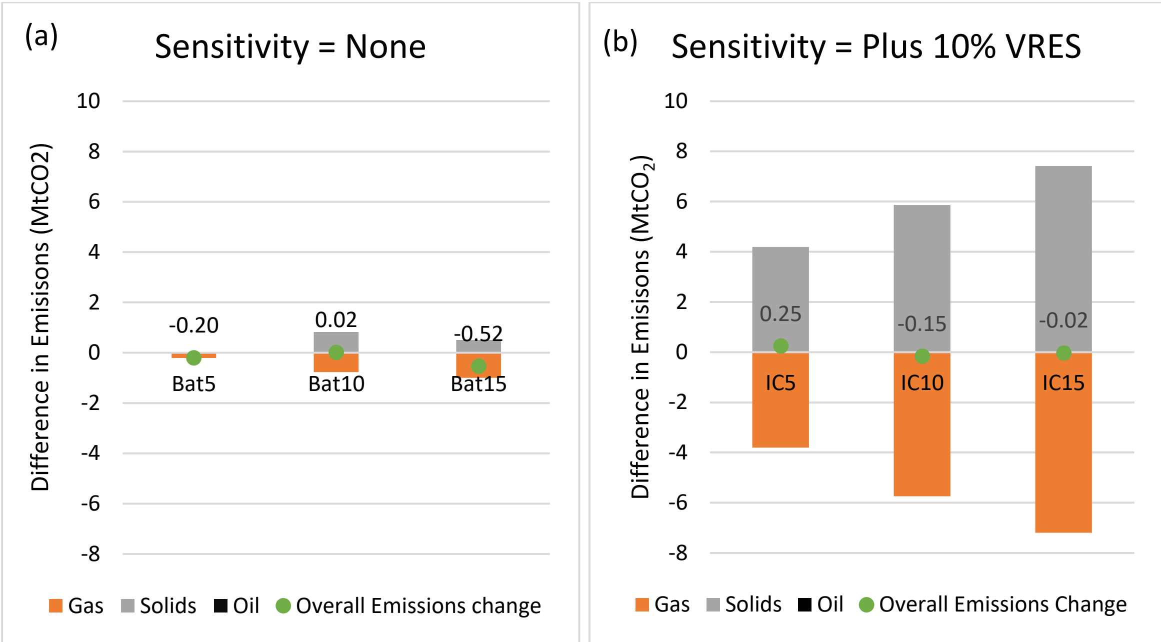


Figure 4-7: Difference in emissions production by fuel type and overall emissions compared to the relative basecase for (a) No sensitivity and (b) Plus 10% VRES capacity

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

4.7.3 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 (Figure 4-8). 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 Figure 4-8). On average increased battery capacity decreased VRE curtailment by 0.25TWh and 0.19TWh more than the reduction achieved by the increased interconnection for the sensitivities 'None' and 'High CO_2 Price' respectively (Table 4-4). Conversely when the grid was not enhanced, increased interconnection capacity decreased curtailment by on average 0.26TWh and 0.44TWh more than the reduction achieved by increased battery capacity for the sensitivities 'Plus 10% VRES' and 'High CO_2 Price Plus 10% VRES'.

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

Table 4-4: Average change in curtailment across increasing capacity by technology compared to the relative basecase

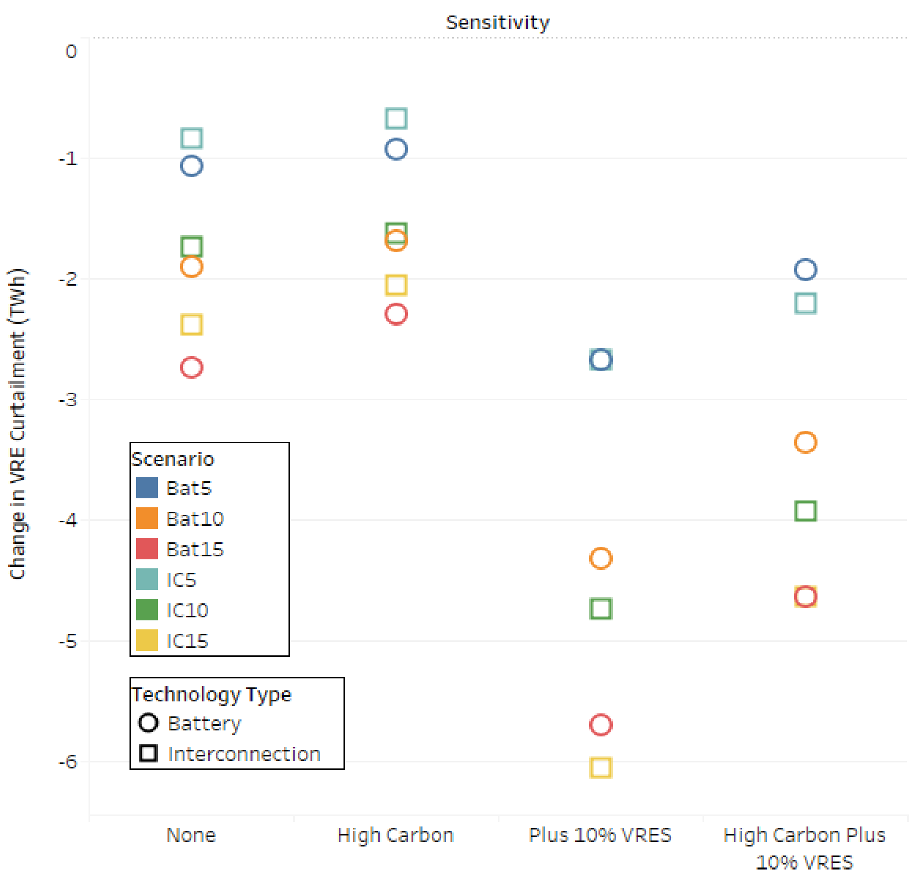


Figure 4-8: Change in VRE curtailment relative to comparable basecase and sensitivity

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 (Figure 4-9(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.

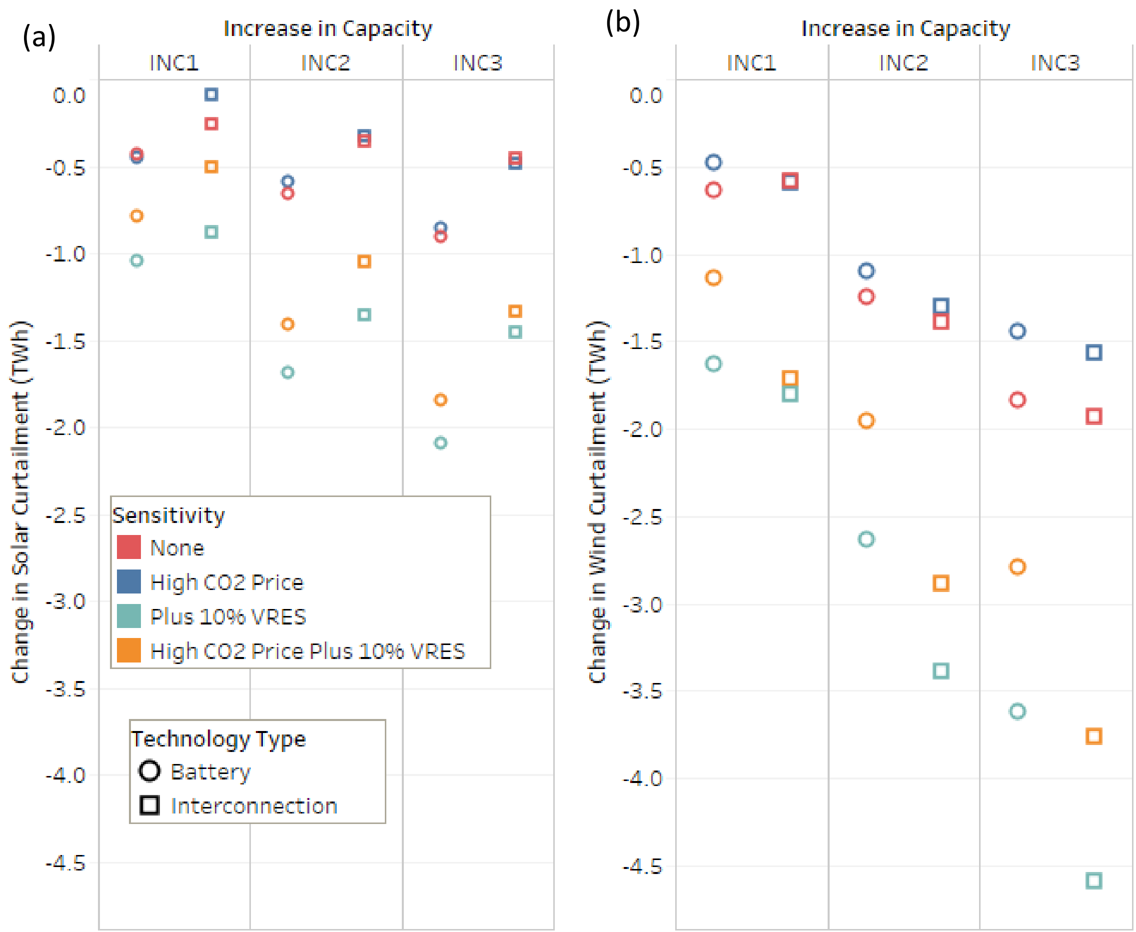


Figure 4-9: Change in (a) Solar and (b) Wind Curtailment Factors relative to the comparable base case and sensitivity

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 [237]. Yet, curtailment is seen as a high risk to investment in renewable technologies [231]. 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.

4.8 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 carbon 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.

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 carbon sensitivity, interconnection emerged as the lead performer in reducing emissions, but batteries also provided reductions. Without a high carbon price, 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 hinderance would likely reduce should there be a lower level of fossil fuels within the generation mix, particularly coal. Across all sensitivities both technologies reduced VRE curtailment, while interconnection alleviated wind curtailment more, batteries lessened solar curtailment more. Regardless of the level of carbon 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.

4.9 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.

Chapter 5: Conclusion

5.1 Introduction

This decade is crucial to keep ambitions of limiting global warming below 2° C and ideally below 1.5° C alive. Within the energy sector which makes up three quarters of global emissions, the electricity system has the potential to play an important role for decarbonisation but there will be challenges to be overcome to achieve this. The overall aim of this thesis was to improve the understanding of these challenges for electricity systems with higher RES and electrification. A multitude of challenges exist, however, the scope of this thesis focused specifically on the next crucial decade and technologies and approaches that are already proven. This thesis considers the mix of centralisation and decentralisation of electricity systems and the role of DG, quantifies the impact of inertia constraints, and investigates the roles of batteries and interconnection in decarbonisation of the European power system. Furthermore, it presents a case study of one synchronous area in Europe demonstrating the challenges and impact of higher renewables and electrification and the scale of change that is required to achieve it within the next decade. This final chapter concludes the thesis by presenting a synthesis of the insights gained from the different chapters including Annex 1. These chapters evolved from the original research questions outlined in section 1.2 which are:

RQ1: What role will DG hold in future electricity systems?

RQ2: What existing or envisaged tool or combination of tools could model future electricity systems with DG?

RQ3: What impact will inertia constraints have in the European power system?

RQ4: What will the impact of increased batteries and interconnection be in decarbonisation of European power system?

These questions will be answered in the following sections.

5.2 Conclusions on the shape of future electricity systems with DG (RQ1) and associated modelling tools (RQ2)

The future role of DG depends on a multitude of often-interrelated factors as determined in Chapter 2. Exploring the factors that influence the role of DG in future electricity systems, as is done in this thesis, improves understanding of the trade-offs for existing electricity systems between maintaining a centralised approach and increasing decentralisation. The impact of these factors will change depending on the area being considered, thus fully understanding the potential roles of DG requires modelling of these factors.

In Chapter 2, following a review of the literature relating to the definition of DG and the drivers and benefits of its deployment, the factors that influence the role of DG are organised into six main categories. The first category reflects that terrain, climate, population density/distribution and the availability of natural resources will influence the role of DG and will also influence the development of electricity infrastructure differently in different areas. The second category considers how existing infrastructure, or the lack thereof, will affect the trajectory of development towards centralisation or decentralisation. The consideration of infrastructure is not limited to electricity, it includes other networks such as district heating and communications. The third category contemplates how the interactions between electricity, heat and transport sectors, and storage within these sectors, particularly the levels of electrification, will play a key role in the future of DG deployment and electricity system development. Fourthly, social factors and the willingness of consumers to accept and interact with DG, the electricity system and the development of infrastructure are considered. The fifth category focuses on the influence regulation, policy and the political atmosphere can have on the role of DG and the prioritisation of operating targets for electricity systems (such as reliability, emissions, cost targets etc). The final category reflects the system challenges and technological requirements of incorporating higher levels of renewables, DG or otherwise, and higher electrification. Examination of these factors confirms that while these factors influence the role of DG, the role of DG is not the main cause of the challenges faced by future electricity systems.

Existing literature considers some of these factors [27] but does not capture their interrelated nature. The interaction of these categories and their associated factors is often complex and highlights the challenges in future electricity system development. For example, the regulatory, policy and political agendas could drive development of a particular generation mix, subject to geographical and climatic factors, which in turn will impact the system challenges that will be faced and the development of existing infrastructure. Yet the development of existing infrastructure will be influenced by public acceptance which falls under the ‘social factors’ category. If the required infrastructure cannot be built or is delayed due to social factors, then the technological requirements for system operation may change and so on. The interaction of these factors, and their associated uncertainties relative to each other as presented in Chapter 2, must be reflected on to fully understand the potential role of DG and the future shape of electricity systems. Furthermore, understanding the uncertainty associated with a factor is key to selecting the appropriate modelling approach to ascertain the impact that factor can have on DG deployment and future electricity system development.

Literature reviewing energy system models [30, 31], electricity system models [32] , electricity distribution network models incorporating DG [28] and distribution generation planning [29] together provide useful lists and categorisation of models. Although, DG is specifically considered in some of the literature [28, 29], the narrow focus on the distribution network, or project level, limited their scope for identifying the ideal tool that captured the factors and interaction of the factors described in this thesis. The ideal tool for modelling future electricity systems with DG considering these factors, as described in Chapter 2, would capture the role of the electricity system in the context of the wider energy system. The tool would encompass energy sector scenarios, electricity generation and network expansion, network analysis, system operation and markets. Capturing this functionality and all the factors that influence DG and ultimately electricity system development, and the uncertainty surrounding those factors, within one tool, if it is even possible, would prove challenging.

An alternative approach is to leverage already available and existing tools to provide insights from different perspectives. There is already a broad range of energy system modelling tools available to suit many study objectives [30]. Energy system modelling tools can incorporate a mix of technology types, including DG, to provide a high-level overview of the generation mix required to meet different decarbonisation targets. Such tools capture the interaction between electricity and other sectors such as heat and transport and can be used to generate electricity demand profiles reflective of such interactions. For more detailed analysis of the electricity system, generation and network expansion planning tools, UCED tools, and power flow and network analysis tools, could be used or a combination thereof. Soft-linking two or more of these tools can provide rich insights into future electricity systems as evidenced in the literature [146, 147, 161] . Thus, utilisation of this methodology could equally provide rich insights into future electricity systems with DG and the challenges faced. This soft-linking approach was used in Chapter 3 to investigate the challenge of declining rotational inertia and in Chapter 4 to explore the role of flexibility providers in decarbonisation. As Annex 1 demonstrates, UCED tools are extremely useful for understanding the impact of different policies and the removal of system constraints on individual synchronous areas within a wider European context.

To conclude, the question of what role DG will play in future electricity systems is a complex one due to the myriad of interrelated factors and the varying uncertainty associated with these factors. The role of DG will be region and system specific and to understand the role modelling is required. The ideal tool for modelling the role of DG and future electricity systems does not yet exist but existing tools can provide insights into the factors that will impact the role of DG and even more significantly the challenges faced in future electricity systems with higher penetration of RES and electrification. Soft-linking two or more of these existing tools make such insights more robust. The role of DG is important, but it is not the key determinant of the challenges faced in future electricity systems with higher penetration of RES and electrification.

5.3 Conclusions on inertia challenge (RQ3)

The future of fossil fuel fired synchronous generators is limited due to their emissions and the need to reduce such emissions to prevent catastrophic climate change. Historically, energy was the prime commodity of these generators; rotational inertia was a free by-product of fossil fuelled generators primarily due to its proliferation, despite its pivotal role in providing system stability. As renewables increase and supplant conventional synchronous generators in the generation mix, the proliferation of rotational inertia is decreasing. Yet, there are few markets that put a monetary value on rotational inertia. This is creating a significant challenge for future electricity systems with higher RES.

Chapter 3 of this thesis investigated this challenge in detail and presented an overview of the status quo for monitoring rotational inertia and options for resolving and managing declining rotational inertia. Some European TSO already monitor rotational inertia. Except for GB, the approach is to estimate inertia by considering the status of large synchronous generators and calculating the combined kinetic energy contribution for the online generators as a proxy for inertia. This approach neglects contributions of generators that are not monitored by the TSO and any contribution of the load to inertia [154]. A direct inertia measurement approach is being rolled out by National Grid UK allowing real time accurate monitoring rather than estimation of inertia [164]. As renewables increase accurate measurement of rotational inertia will be essential to ensure stability of power systems and to avoid unnecessary curtailment of renewables when there is sufficient rotational inertia on the system.

Grid forming inverter technologies have gained attention both from academia and power system operators as a potential solution [151], but the lack of real-world examples thus far suggests the technology is far from becoming mainstream. Proven technologies exist such as synchronous condensers that provide rotational inertia in addition to adjustable reactive power and improved short circuit strength. Developing technologies such as grid forming inverters, and the use of proven technologies such as synchronous condensers, may well be part of the enduring solution as indicated in the literature [150, 151, 153]. However, the evolution of other negative emissions technologies, such as CCS as investigated in Annex 1, could provide energy and stability benefits including rotational inertia thereby having an advantage over non-energy inertia providers. The uncertainty surrounding future technological development and policy support for such developments has resulted in some system operators, with significant penetration of renewables, already facing declining rotational inertia. One tool that is available to TSO to manage the risk of declining rotational inertia is to enforce minimum inertia levels.

This thesis considers the inertia challenge from a wider European perspective. Chapter 3 explored and quantified the impact of minimum inertia constraints for five synchronous areas in Europe for the year 2030. The methodological advancement over other literature that used a soft-linking approach to examine inertia from a wider European perspective [161] is the consideration of two divergent decarbonisation scenarios, two ROCOF limits, and the analysis of the distribution of inertia across Member States. On an individual synchronous area basis, the impacts of minimum inertia constraints were found to depend on the severity of the constraint, the size of the synchronous area and the generation mix. Synchronous areas with more hydro generation resources and/or nuclear in the generation mix were not impacted as badly as those that were dependent on fossil fuel fired generators alone for providing rotational inertia. This was evident in the differences in impact between the synchronous area of Ireland and Northern Ireland and the Baltic states which shared the same minimum inertia limits. For the two synchronous areas of the Nordic States and Continental Europe, there was no breach of minimum inertia levels for any hour of the simulations in either scenario. The proliferation of hydro in the generation mix aiding the former while the sheer size benefiting the latter along with the volume and mix of generators required to meet demand.

Annex 1 considered the impact of relaxing/removing stability constraints on the synchronous area of Ireland and Northern Ireland. A model of the European power system is used, like the model used in Chapter 3, although the constraints are only applied to the synchronous area of Ireland/Northern Ireland. The stability constraints included a minimum inertia constraint to limit ROCOF to 1Hz/s, a constraint to always maintain a minimum number of conventional units on, and an SNSP constraint to limit the amount of non-synchronous generation. Removing the minimum inertia constraint and relaxing the other two constraints resulted in a 0.9MtCO_2 reduction, leaving emissions for the island just on the outer envelope of what is required under the Paris Climate Agreement. A reduction in net exports from the island was observed with the removal/relaxation of constraints. The same trend emerged in Chapter 3 where relaxing minimum inertia constraints reduced exports from Ireland/Northern Ireland to neighbouring synchronous areas. Indeed, the analysis in chapter 3 showed for the lower ambition scenario the more binding a minimum inertia constraint was in one synchronous area the bigger the benefit to its neighbours in terms of cost and emissions. This demonstrates the flexibility benefit of interconnection mentioned in the literature [78, 212], as renewables that cannot be accommodated in one synchronous area due to the constraint can be shifted to another. Furthermore, it highlights the importance of considering the challenge in the wider European context and from different perspectives.

The study in chapter 3 revealed that for the less ambitious scenario, while there were higher costs and VRE curtailment with increasing levels of constraint, CO_2 emissions reduced. The constraint caused coal to gas switching as CCGTs contribute twice as much rotational kinetic energy as coal fired generators in the study. However, for the heavily decarbonised scenario the harsher the constraint the higher the cost, VRE curtailment, and CO_2 emissions, across the pan European system. Thus, inertia constraints can be useful on the path to a decarbonised electricity system, but there will come a point in the transition to future electricity systems with higher RES where they will impede progress. Other literature has also concluded that alternatives to constraints on synchronous generation need to be investigated to solve the inertia challenge [156].

The application of minimum inertia constraints is not without pitfalls. This was demonstrated in the analysis of the distribution of rotational inertia across Continental Europe for the hour where rotational inertia was at its lowest presented in Chapter 3. Even though the minimum inertia level for the synchronous area was met, there were several localised rotational inertia deficiencies observed. It is essential to perform dynamic stability studies to ensure that minimum inertia constraints will be effective and to identify the disaggregation of minimum inertia constraints required in large synchronous areas such as CE. The fundamental reason for this is that the location of inertia providers is just as important as the overall amount to ensure frequency stability for credible contingencies [155].

Declining rotational inertia is one of the key challenges facing electricity systems with higher RES. Permanent proven solutions to remedy rather than manage declining rotational inertia due to decreasing amounts of conventional synchronous generators already exist and new technological solutions are being actively researched. However, some TSO due to the relative penetration of renewables are already facing this challenge and have opted to use minimum inertia constraints to limit ROCOF to manage the problem and ensure frequency stability. In the absence of other solutions being deployed, carefully designed minimum inertia constraints are useful in the transition to higher penetrations of RES. However, they are not an enduring solution, increase costs and VRE curtailment, and at some stage in the transition will impede progress towards European decarbonisation targets.

5.4 Conclusions on flexibility providers' roles in decarbonisation (RQ4)

Power systems with increased renewables are more susceptible to weather related variability [188]. There will be times in the future that higher RES will produce more electricity than can be absorbed by normal demand and other times where RES will not produce enough power. Future electricity systems require more flexibility to cope with this [211]. Higher electrification and the roll out of smart meters for home heating and home EV charging can provide some of the flexibility assuming it is moveable. Flexibility can also be provided by proven technologies such as interconnection and batteries that can shift power from where/when it is in surplus to where/when there is a deficit.

The case study presented in Annex 1 highlights how RES-E ambition affects the flexibility required for one synchronous area in Europe, i.e., on the island of Ireland. Batteries would be required to increase from zero in the 2020 system to 1.1GW for a 70% RES-E ambition. This increases to 3.5GW if renewable ambition increased by 5GW. Similarly, interconnection export capacity would be required to increase from less than 1GW in the 2020 system to 2.2GW for a 70% RES-E ambition or 5GW for the higher renewable ambition scenario. The higher RES-E ambition scenario considered in Annex 1 focuses a spotlight on the reality of policy ambitions in terms of required development. A sensitivity conducted as part of this work where France and GB increased wind capacity by 10% demonstrated that net imports increased and net exports decreased, emphasizing the need to be cognisant of the speed of transition in neighbouring synchronous areas as interconnected neighbouring power systems can impact each other's individual ambitions.

Chapter 4 addressed a more fundamental question than the literature that sought to identify optimum or least cost future technology mixes considering flexibilities [213, 226]. It explored if, while providing flexibility, batteries and interconnection directly impact decarbonisation. A high carbon price is key to ensuring that batteries and interconnection reduce emissions, particularly when CO_2 intensive fuels like coal remain in the generation mix as determined in Chapter 4. If a high carbon price is not in place, batteries and interconnection could negatively impact decarbonisation, although this would likely diminish as fossil fuels are phased out. With a high carbon price, interconnection outperformed batteries in reducing emissions, confirming the benefit of pursuing the European ambition of increased centralisation via interconnection.

There was alignment between Annex 1 and Chapter 4 with regards to curtailment. In Annex 1, batteries and interconnection were iteratively adjusted to lower VRE curtailment to a prescribed level, and across all scenarios examined in Chapter 4, batteries and interconnection were found to lower VRE curtailment. Interestingly, it emerged that batteries reduced solar curtailment more than interconnection, while interconnection reduced wind curtailment more than batteries in the analysis conducted in Chapter 4. As VRE curtailment is a risk of increasing importance to investors [231], understanding the impact of these flexible technologies on this risk is also increasing in importance.

In 2030, batteries and interconnection undoubtedly have a role to play providing flexibility in transitioning to electricity systems with higher RES and electrification. To ensure that, in addition to providing flexibility, batteries and interconnection directly reduce emissions, a high carbon price and careful planning of the location, capacity and operational dispatch of these technologies is needed.

5.5 Other conclusions

Reliability is a fundamental requirement for future electricity systems with higher RES and electrification. Over 30 weather years were examined in Annex 1 and several 2-week windows highlighting vastly different generation dispatches during different weather conditions epitomised the methodological achievement of this part of the thesis. The ability of electricity systems to withstand long periods of dark, calm, cold weather covering large geographical areas, where system demand will be high and solar and wind generation will be low, requires backup generation as batteries, interconnection and demand side management may not be sufficient. Indeed, this work is not alone in identifying an enduring need for backup generation, it was also a conclusion of a study investigating a 100% renewable European power system [228]. Bearing in mind that system demand may be significantly higher due to increased electrification, the capacity of this backup generation may be higher than that available today, yet the running hours will be lower than those in 2020 as highlighted in the case study in Annex 1. Getting the balance between ensuring reliability in the next decade and driving timely investment in appropriate technologies that will reduce emissions is key.

Speeding up the decarbonisation of the electricity sector has been pinpointed as "*the single most important way to close the 2030 ambition gap*"[6]. The scale of the transformation required in the decade out to 2030 to achieve electricity systems with higher RES and higher electrification and keep the ambitions of the Paris Climate Agreement alive should not be underestimated. For example, as indicated in Annex 1, on the island of Ireland more renewables must be connected to the electricity system in the decade out to 2030 than have been connected in the previous two decades. This is on top of significant deployment of batteries and additional backup generation and rolling out solutions to relax or remove the constraints for minimum inertia, limiting SNSP, and requiring a minimum number of conventional units discussed earlier.

The electricity sector is a potential key enabler of decarbonisation of other sectors through electrification but will only be successful in this aim if it can integrate higher amounts of RES. Otherwise, electrification will simply shift CO_2 emissions from one sector to another. For the pan European power system, uniting to achieve collective goals like increased interconnection mean that even though challenges may be faced at different times for individual synchronous areas, navigating those challenges can be turned into positive impacts for neighbouring synchronous areas. The scale of the transformation needed out to 2030 means that there is no time for inaction.

5.6 Future Work

This thesis was designed to improve understanding of the challenges of future electricity systems with higher RES and higher electrification within a limited scope and focusing on key technical challenges including rotational inertia and flexibility provision. This work could be extended further by considering how to marry the need for backup generation and system services like inertia currently provided by conventional synchronous machines in the next decade without locking in fossil fuel generation for longer than it is needed and thereby delaying the roll out of other technologies that reduce emissions. It would be important that the outcome of this investigation would be communicated in a manner that is digestible to a wide audience like the report presented in Annex 1. It became apparent to the author of this thesis that key messages from research like the ones in Annex 1 are more likely to reach decision makers such as politicians and policy makers than academic literature. That is not to say academic literature is not extremely important as the peer review process is invaluable. It is to point out that research, relating to short time frames identifying a need for action, needs to be communicated in a manner that allows it to be easily understood by the those that need to act.

A limitation of the thesis and the studies undertaken was that they did not consider internal transmission networks within a country. This could be improved by creating nodes to represent regions within countries coupled with constraints reflecting network congestion. Although, the ability to do this would be very much limited by the data publicly available. If, possible though, this would allow for even more detailed insights into the challenges faced.

One of the thesis conclusions was that DG has an important role to play but was not the key determinant of the challenges faced. With increasing DG, the role of the distribution network will become more important. An examination of how distribution systems and the proliferation of devices at lower voltage levels could be leveraged to provide benefits to the entire system is warranted. Soft-linking a distribution modelling tool such as OpenDSS with a UCED seems like a suitable choice for this work.

Annex I: Our Zero e-Mission Future

The following annex is an abridged version of the Our Zero e-Mission Future report I was lead author of and which Dr Paul Deane co-authored. The full report is available online [22]. The report is intentionally written in a non-academic style to appeal to a wide audience, yet the results and findings of the report are made following a robust academic process which involved full review of relevant energy and electricity sector policies and relevant reports, scenario development and electricity system modelling via PLEXOS. The report was launched by the Minister for Environment, Climate and Communications and Minister for Transport in Ireland, Eamon Ryan TD, and Richard Rogers, Head of Energy, Department for Economy in Northern Ireland. It has been circulated widely, gaining coverage in the national media in Ireland [243]. For this work I was awarded an Early Research Impact Award from my research institute in 2020 [244]. In addition, this research, particularly the message on the requirement for backup generation, has informed recent policy decisions in Ireland [245].

I.0 Summary

A decarbonised All-Island electricity system is key to achieving climate ambition on the island of Ireland. This study takes a closer look at the future All-Island power system through the lens of decarbonisation by focusing on the year 2030 where over 70% of the annual electricity on the system will be renewable. While this requires a significant level of renewable energy build out, it also demands a resilient power system capable of absorbing and storing fluctuations in weather driven generation and at the same time meeting the demand of new electricity loads from electric cars, residential heating, and data centres. Ireland's location on the edge of Europe presents a limited diversity of interconnection options and so our role within a greater interconnected European power system is also considered.

A reliable electricity supply is integral to our modern economy and while climate policy is often based on average values, power systems must be resilient to extremes to maintain the continuity of supply that society has become accustomed to. Our analysis examines over 250,000 hours of weather data across the island of Ireland and highlights how remarkably flexible the future All-Island power system will have to be to deal with a wide and diverse variation in weather events. At times, the system will produce more renewable generation than can be used, stored, or exported. Yet, it must be sufficiently resilient to deal with periods of low regional wind generation and extremes such as periods where there is very little power being supplied by renewables. Conventional generators and interconnectors meet the bulk of

electricity demand during periods of low regional wind availability helped with smart loads, demand side response units and batteries.

Today the All-Island electricity sector is responsible for approximately 20% of final energy use and 16% of greenhouse gas emissions. The challenge of a fully decarbonised economy will require a greater contribution from electricity to final energy to assist wider system decarbonisation, coupled with a strong reduction in emissions from the sector. It also requires us to look not only at how we supply electricity but how it is integrated into the grid and managed in demands.

To align with the objectives of the Paris Climate Agreement, we find that a 2030 system with a minimum of 70% renewable electricity generation is correct in terms of ambition for the All-Island power system in addition to huge changes across other sectors, but today’s grid is not adequately flexible to deliver this ambition. This goal can only be fully realized with actions that increase the capability of the grid to absorb the greatest amount of renewable generation. In the absence of such actions the power system will be outside the upper bound of what is required in terms of emissions reduction.

Clear Climate Policy provides clarity on the pace of emission reductions required and reduces the risk of carbon lock in for new investments. A greater effort in decarbonisation today will reduce the burden of effort post 2030 and this report also reviews options for different technologies that could further assist decarbonisation in the future. While these options all have implicit uncertainty, they share a requirement for significant capital commitment[7], long lead times for construction, decades-long operational lifetime and a need for investment decisions to be made well in advance of 2030. A dialogue on the future pathways for the power system is required to ensure the correct policy signals are provided to stakeholders that best position the sector to meet our decarbonisation obligations in the long term.

However, this progress cannot be taken for granted and in particular we highlight the following key messages:

- **Achieving a high renewable ambition across the All-Island power system requires the System Non-Synchronous Penetration (SNSP) level to increase to over 85%, grid**

[7] The cost and source of funding for the capital investment required is outside the scope of this report.

constraints removed and continued investment in flexibility and grid infrastructure. Without this, emissions will increase, and a lower ambition will be realized.

- Electrification of new loads in heat and transport plays an important role in wider system decarbonisation. **To maximise the benefit of renewable generation for emissions reduction, the rate of electrification of new loads, particularly in switching from high-carbon fossil fuel, must keep pace. Slower uptake on technologies such as heat pumps and electric vehicles has a net increase on wider energy system emissions.**
- **While wind energy will be the main driver of decarbonisation, the reliable delivery of electricity requires conventional generation to play a necessary role providing energy, system services and flexibility.** The required gas fired capacity in 2030 is similar to today, but gas fired generation will operate less [~20% less energy compared to 2019 (or ~ 4 TWh less)]. Options to decarbonise conventional generation beyond 2030 need to be examined now to ensure investment and action in a timely manner.
- **All-Island power system emissions should not be greater than 6.2 million tonnes in 2030 to be in line with obligations under the Paris Climate Agreement**. The modelled All-Island 2030 system is just on the outer envelope of this range [~6.3 million tonnes]. Efforts to reduce emissions should be pursued to bring the system in line with expectations and reduce the burden of decarbonisation post 2030.
- Significant investment must be made across both the power system and wider energy system to achieve ambitious levels of emissions reduction on the All-Island system. Based on public data, **we estimate an 'overnight' cumulative investment of ~32€ billion for the All-Island power system with 90% of costs on physical infrastructure such as wind turbines and grid delivery and 10% on system services to facilitate the operation of the power system with high levels of renewables.** This level of investment requires strong and stable policy signals to deliver on climate ambition.
- **As policy across the UK, Ireland, and Europe shifts from a renewables target focus to an emissions reduction focus there is a need to promote decarbonisation across the full system including supply, grid and demand side measures.** Policy coordination in the All-Island System and cooperation mechanisms across the UK and Europe will help maximize the benefit of decarbonisation across the full energy system.

Decarbonisation Options compared to All Island 2030 Base Scenario 6.3 Mt CO2			
Remove Min Units Requirement	**Additional Wind Capacity**	**Additional Wind Capacity + remove Min Units**	**Carbon Capture and Storage Plant**
			
Would remove an additional 0.8 Mt CO2	**Would remove an additional 1.3 Mt CO2**	**Would remove an additional 2.9 Mt CO2**	**Would remove an additional 1.1 Mt CO2**
Investment would likely be needed in synchronous condensers, flywheel storage, or novel synthetic inertia schemes. Capital cost is uncertain	Investment in extra interconnection (+2.8GW), Batteries (+2.4GW) and offshore grid infrastructure. Deployment timelines and supply chain must be considered. Policy on carbon credits of exported power should be developed	Combining increased deployment of wind and removal of min units requirement would deliver significant emissions reduction and would require significant and sustained investment	Investment is required in plant and storage capacity as well as long term stable policy and likely political support. Residual emissions of CCS in a long-term energy system must be considered in wider decarbonisation context

Figure I-1: Decarbonisation options examined and emissions reduction compared to Base Scenario. Note that measures are not additive

I.1 The role of electricity in climate action

Our planet is warming and this is changing our climate in dangerous ways. Every 1 second over 1,000 tons of carbon dioxide (CO_2) is released into our global atmosphere, trapping the sun's heat, and warming our environment. Now more than ever, there is political and societal recognition for the need to reduce our emissions and decarbonize our complete energy system. The Paris Climate Change Agreement has the objective of holding the increase in the global average temperature to well below 2 °C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5 °C above pre-industrial levels [246]. The science underpinning this ambition demonstrates a uniquely important role for a decarbonized electricity sector as a vector for clean energy but also as the backbone to a resilient and secure energy future.

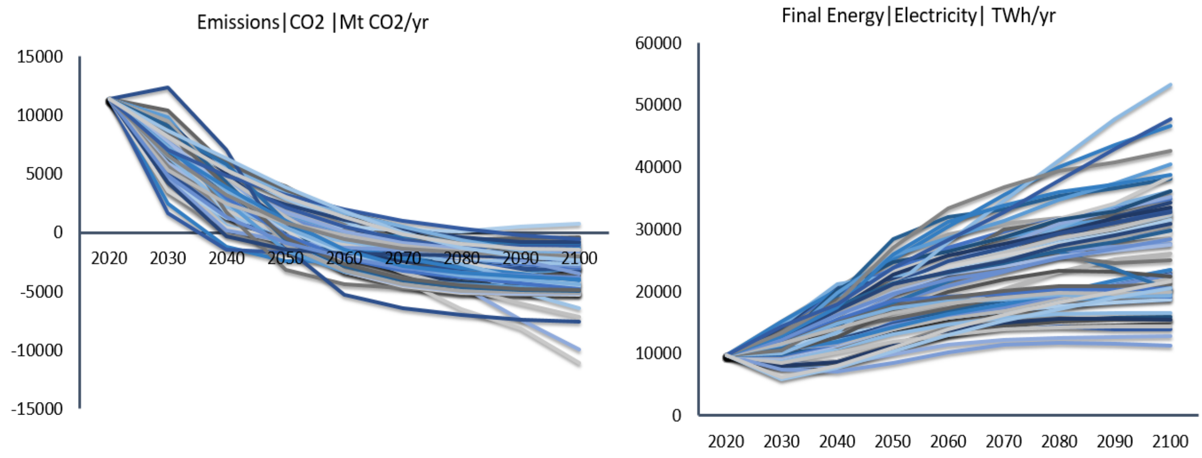


Figure I-2: Pathways for CO_2 reduction and electricity demand in IPPC Pathway that meet the global ambition of 1.5 degrees for the EU and OECD region ["IAMC 1.5°C Scenario Explorer and Data hosted by IIASA, release 1.1"]

The Intergovernmental Panel on Climate Change (IPCC) Special Report on 1.5 degrees presents an overview of emissions reduction and the associated quantity of electricity required in our global energy system in pathways that limit future temperature increase [247]. Today, the global electricity system meets 20% of our final energy needs and under scenarios that meet the Paris Climate Agreement this is projected to increase to 50% by 2050 and even higher in some regions. In fact, all modelled future scenarios that meet the 1.5 °C target share a number of robust findings for the electricity sector, including a growth in the share of energy derived from low-carbon-emitting sources, a steep decline in the overall share of fossil fuels without Carbon Capture and Storage (CCS), a rapid decline in the carbon intensity of electricity generation simultaneous with further electrification of energy end-use such as mobility, heating and industrial processes. While the All-Island system is much smaller in scale and magnitude, these core findings are fundamentally relevant in efforts to meet climate obligations.

I.2 The All-Island energy and climate policy

Despite variances in climate and energy policy, the All-Island electricity market is a story of success. Almost 13 years ago the Single Electricity Market was established, operating across two jurisdictions and with dual currencies (Euro and Sterling), it was the first market of its kind in the world when it opened. Today, the system is a world leader in the integration of variable renewables with almost 40% of electricity generated to come from clean renewable sources in 2020. This section presents the policy drivers for decarbonisation on the island and sets the context for the role of electricity as the main vector for decarbonisation.

I.2.1 Northern Ireland Policy Context

Northern Ireland has devolved responsibility for energy policy, excluding Nuclear Energy and Carbon Capture and Storage. The decarbonisation of the energy system will be vital to ensuring Northern Ireland meets its contributions to the UK's target of net-zero emissions by 2050.

Currently, Northern Ireland does not have any legally binding emissions reduction targets; however, it will contribute to the UK's stated aim to achieve net-zero emissions by 2050. In May 2019, the United Kingdom's Committee on Climate Change concluded that it is "necessary, feasible and cost-effective for the UK to set a target of net-zero Green House Gas (GHG) emissions by 2050" [248]. Following this, the Climate Change Act 2008 (2050 Target Amendment) Order 2019 came into effect on the 27 June 2019 [249]. The revised legally binding target towards net zero emissions covers all sectors of the economy. This update to the Order demonstrates the UK's and Northern Ireland's commitment to targeting a challenging ambition in line with the requirements of the Paris Agreement. The 'New Decade New Approach' deal also specified Northern Ireland's commitment to the Paris Agreement: "The Executive will introduce legislation and targets for reducing carbon emissions in line with the Paris Climate Change Accord" [250]. Furthermore, the Department for the Economy is currently preparing a new long-term strategy for decarbonisation of the Northern Ireland energy sector by 2050 at least cost to the consumer [251].

Northern Ireland has witnessed significant reductions in overall GHG emissions and in 2018 were almost 18% below 1990 levels. By contrast, Ireland's GHG emissions in this period have grown by 10% and UK GHG emissions have reduced by 42%. Currently, the energy sector is responsible for two thirds of Northern Ireland's GHG emissions, but the bulk of emissions reduction have taken place in the electricity and industry sectors. Electricity is still a significant source of emissions and decarbonisation of the energy system is therefore critical to mitigate the impact of climate change. The Strategic Energy Framework (SEF) 2010-2020 sets a target of 40% of electricity consumption in Northern Ireland to be met from renewable generation by 2020 and significant investment in renewable generation enabled Northern Ireland to achieve the 40% target in 2019 [252].

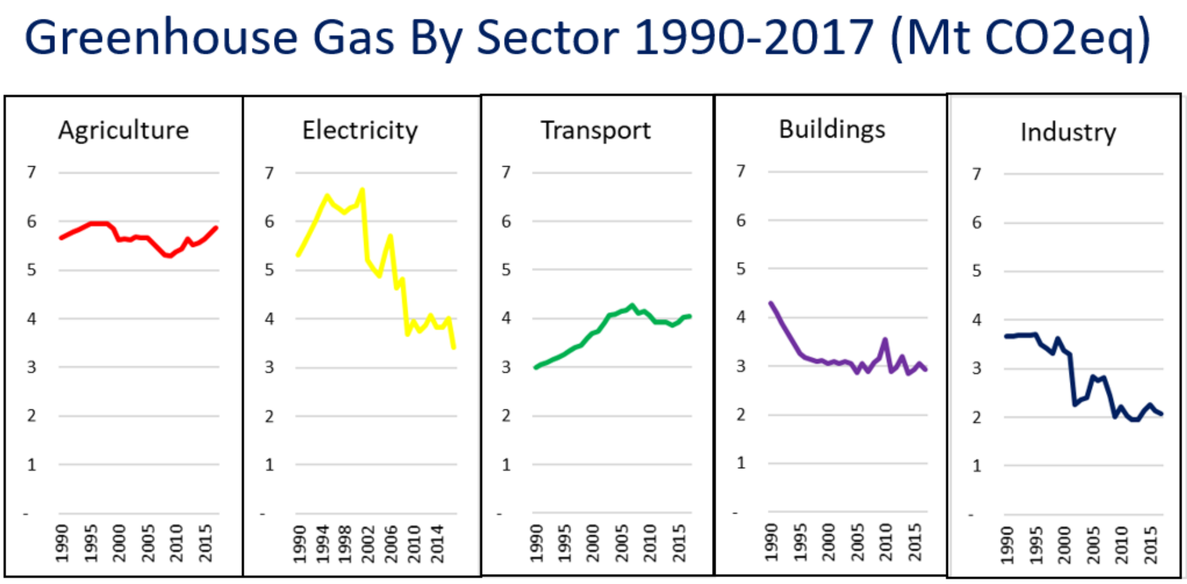


Figure I-3: Northern Ireland Greenhouse gases from 1990-2017 for major sectors of the economy

I.2.2 Ireland Policy Context

Ireland has a complex set of overlapping national and European targets that have important relevance for the electricity sector. The ambition is broken out between emissions reduction for certain sectors and renewable energy targets for others. We present these separately below. The Irish Government published its Climate Action Plan in 2019 [253]. The objective is to enable Ireland to meet its European targets to reduce its carbon emissions by 30% between 2021 and 2030 in sectors not included in the EU Emissions Trading Scheme (i.e., all sectors apart from large industry and electricity) and lay the foundations for achieving Net Zero carbon emissions by 2050.

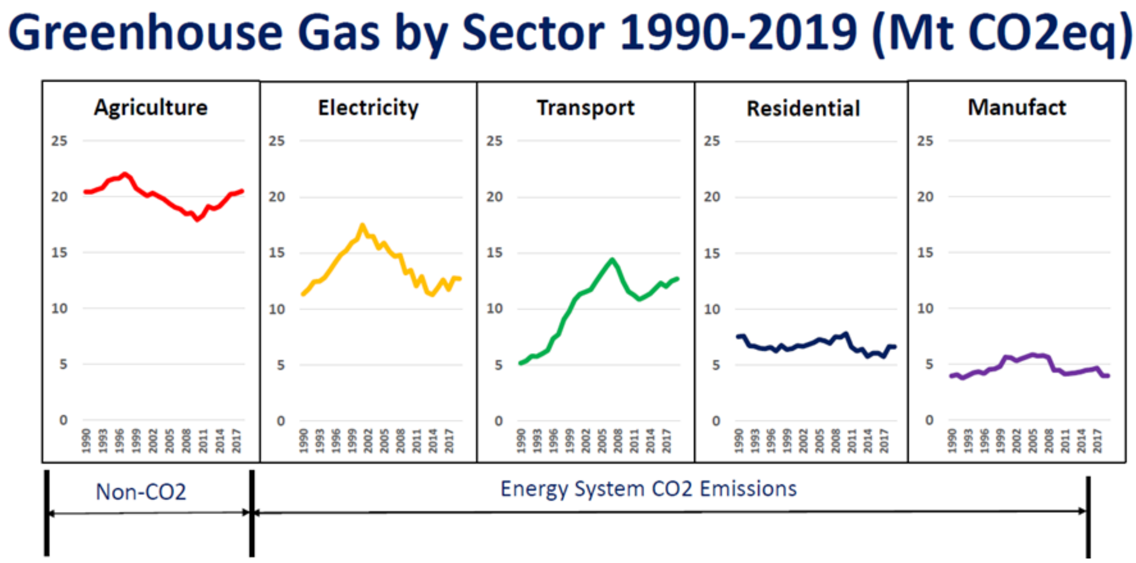


Figure I-4: Ireland Greenhouse Gases from 1990-2019 for major sectors of the economy

Emissions Reduction Targets: Ireland's 2020 target is to achieve a 20% reduction of non-Emissions Trading Scheme (non-ETS) sector emissions (i.e., agriculture, transport, residential, commercial, non-energy intensive industry, and waste) on 2005 levels with annual binding limits set for each year over the period 2013-2020. New 2030 targets for EU Member States were adopted by the European Council in 2018. Irelands 2030 target under the Effort Sharing Regulation (ESR) is a 30% reduction of emissions compared to 2005 levels by 2030 [202]. There will be binding annual limits over the 2021-2030 period to meet that target.

In relation to 2020 EU targets, Ireland is set to miss its target for compliance for emissions reduction. Ireland's non-Emissions Trading Scheme emissions are projected to be between 2% to 4% below 2005 levels in 2020 and will have to purchase compliance to meet its obligations.

Moving Emissions from Non-ETS to ETS Sectors: Ireland does not have emission reduction targets for electricity, as these are within the European Union Emissions Trading Scheme, however there is an important interplay between the ETS and Non-ETS sectors in relation to the electrification of new load that has policy consequences. When electrification of new transport or heating loads take place (for example through EVs or electrification of residential home heating) this reduces the emissions burden for the State as it shifts the emissions responsibility to companies in the ETS sector. Thus, the electrification of new loads offers an important policy benefit.

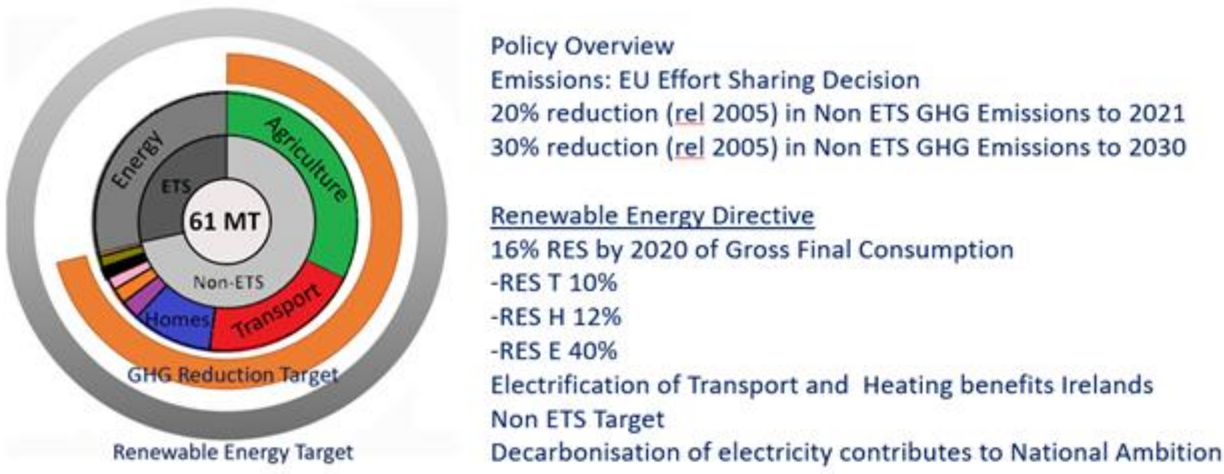


Figure I-5: Ireland Emissions and European renewable and climate obligations

Over the longer term, Ireland's National Policy Position on Climate Action and Low Carbon Development has set a target of an aggregate reduction in carbon dioxide (CO_2) emissions of at least 80% (compared to 1990 levels) by 2050 across the electricity generation, built environment and transport [254]. The long-term vision of low-carbon transition is also based on, in parallel, an approach to carbon neutrality in the agriculture and land-use sector, including forestry, which does not compromise capacity for sustainable food production. This policy position is evolving. The Programme for Government states that "We are committed to an average 7% per annum reduction in overall greenhouse gas emissions from 2021 to 2030 (a 51% reduction over the decade) and to achieving net zero emissions by 2050. The 2050 target will be set in law by the Climate Action Bill, which will be introduced in the Dáil within the first 100 days of government, alongside a newly established Climate Action Council" [255].

I.2.3 Renewable Energy

The Renewable Energy Directive (RED) sets out two mandatory targets for renewable energy in Ireland to be met by 2020 [201]. The first relates to overall renewable energy share (RES), commonly referred to as the overall RES target. For Ireland, the overall RES target is for at least 16% of gross final energy consumption (GFC) to come from renewable sources in 2020.

The second mandatory target set by the RED relates to the renewable energy used for transport. This is commonly referred to as the RES-T target. The RES-T target is for at least 10% of energy consumed in road and rail transport to come from renewable sources. In addition to these EU mandatory targets, Ireland has two further national renewable energy targets for 2020. These are for the electricity and heat sectors and are designed to help Ireland meet the overall RES target. The renewable electricity target is commonly referred to as the RES-E target. The RES-E target is for 40% of gross electricity consumption to come from renewable sources in 2020. The renewable heat target is commonly referred to as the RES-H&C target. The RES-H&C target is for 12% of energy used for heating and cooling to come from renewable sources in 2020.

Ireland is projected to miss its 2020 Renewable energy target of 16% and will have to purchase statistical transfers from other EU Member States to meet compliance.

At the time of writing, the European policy landscape is in a state of flux and overall renewable energy targets for Member States are yet to be formally decided. The recently published National Climate and Energy Plan 2021-2030 has indicative targets for Ireland as 34% for 2030, with a target of 70% for RES-E, 13% RES-T and 24% for RES-H&C with only the RES-E target formally committed to in the program for government [255, 256].

I.3 The All-Island power system

The power system on the island of Ireland is one of the most agile in Europe. Wind generated electricity on the system frequently meets up to 65% of instantaneous electricity demand and approximately 40% annual renewable electricity generation is expected in 2020. In contrast with other EU member states, the power system has limited interconnection to neighbouring countries, has low levels of storage and low levels of hydropower.

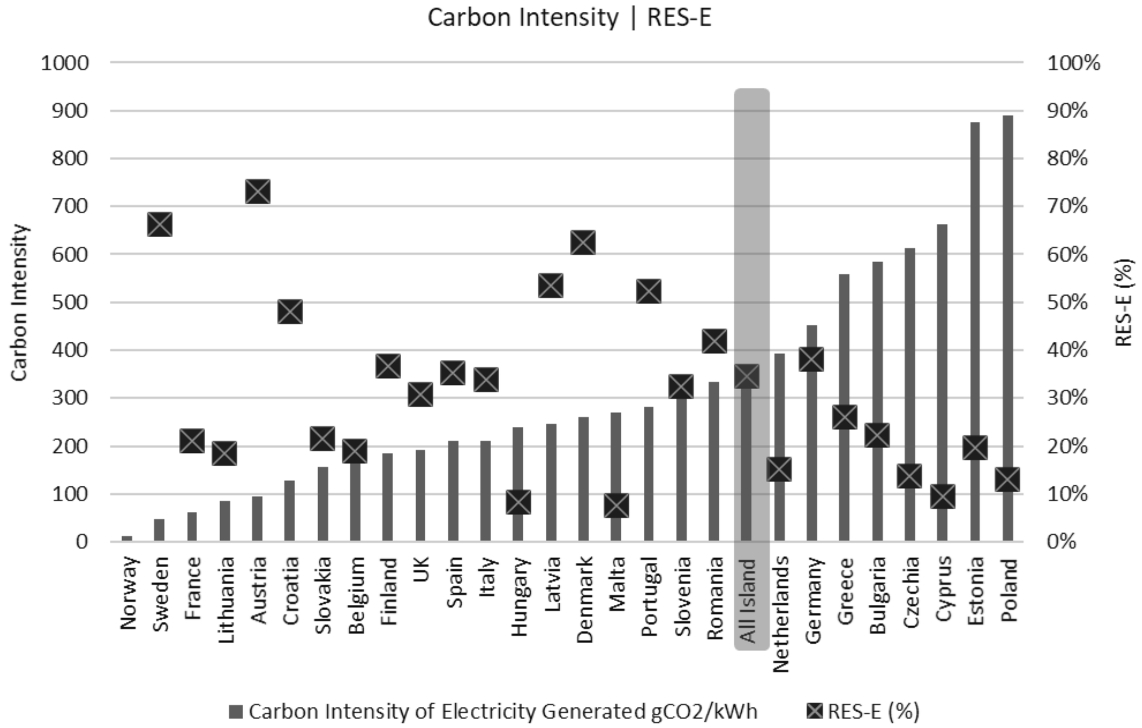


Figure I-6: Carbon Intensity (left axis gCO_2/kWh) and Renewable Electricity Penetration (right Axis %) in 2018 for European countries. The All-Island System is highlighted in blue.

The All-Island system has a level of renewable electricity above the EU average (ranked 12th in the EU 28 in 2018) and the carbon intensity of the All-Island system is estimated at 340 gCO_2/kWh for 2018, this is above the EU average for countries shown in Figure I-6 of 280 gCO_2/kWh.

Due to its isolated grid, the current level of wind generation is limited to ensure system strength is maintained. Achieving a minimum of 70% renewable electricity by 2030 will require significant infrastructure investment as well as capacity to integrate new storage technologies. According to the government's Climate Action Plan in Ireland, the level of wind capacity may have to increase by up to 300% to achieve the higher level of ambition but also to absorb new electricity loads from electric cars, electric heat pumps and significant growth in Ireland's data centre industry.

The EU has set an interconnection target of at least 10% by 2020 (Ireland's level was 7% in 2017), to promote security of supply and encourage countries to connect their installed electricity production capacity to share resources. There are already two interconnectors between the island of Ireland and the UK, one in Ireland and one in Northern Ireland. An additional two interconnector projects are at a preliminary stage: Greenlink between Ireland

and the UK and the Celtic Interconnector the first planned interconnector between Ireland and France. Ireland's location on the periphery of Europe limits its diversity in terms of interconnection options. This challenge can be addressed to a degree through the introduction of storage technologies and flexibility solutions into the energy system.

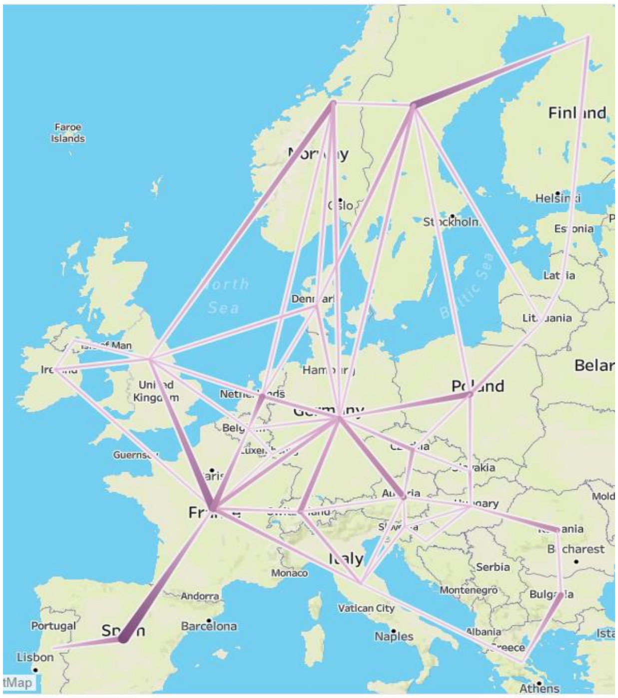
The power system on the Island is one of the most reliable power systems in Europe. The total system minutes lost (SML)[8] due to faults on the main system for 2019, attributable to SONI was 0.92 and EirGrid was 0.17. Significant reductions in outages for customers have also been achieved by increasing network reliability and storm resilience [257].

[8] System minutes lost is a measure of the energy not supplied for a disturbance. The metric takes account of the load lost (MW), duration of disconnection (minutes) and peak system demand (MW).

I.4 Methodology

I.4.1 Pan European Model Development

To understand the future 2030 All-Island Power System, MAREI has developed an extensive Pan-EU power market model covering EU 27, United Kingdom and Norway for the purpose of this study. The model uses the PLEXOS Integrated Energy Software that is widely used in the power and utilities industry for market price projections, asset dispatch modelling, and other purposes. The model takes key inputs and scenario assumptions such as hourly demand profile, fuel prices, generation portfolios and hourly wind and solar profiles, and has representations of generator technical parameters and interconnection between countries. The model undertakes a least cost optimization to produce hourly dispatch for the generators and hourly prices for the markets taking full consideration of the operational constraints (ramp rates, start time, availability etc.).



Why model all the EU

Ireland's location on the edge of Europe means the dominant influence on Ireland's climate is the Atlantic Ocean but we experience a range of air masses with different sources and tracks, giving us our variable weather. As the EU power grid becomes more interconnected fluctuations in weather driven electricity generation can be absorbed by interconnectors and transmitted across Europe meaning that what happens elsewhere in Europe matters.

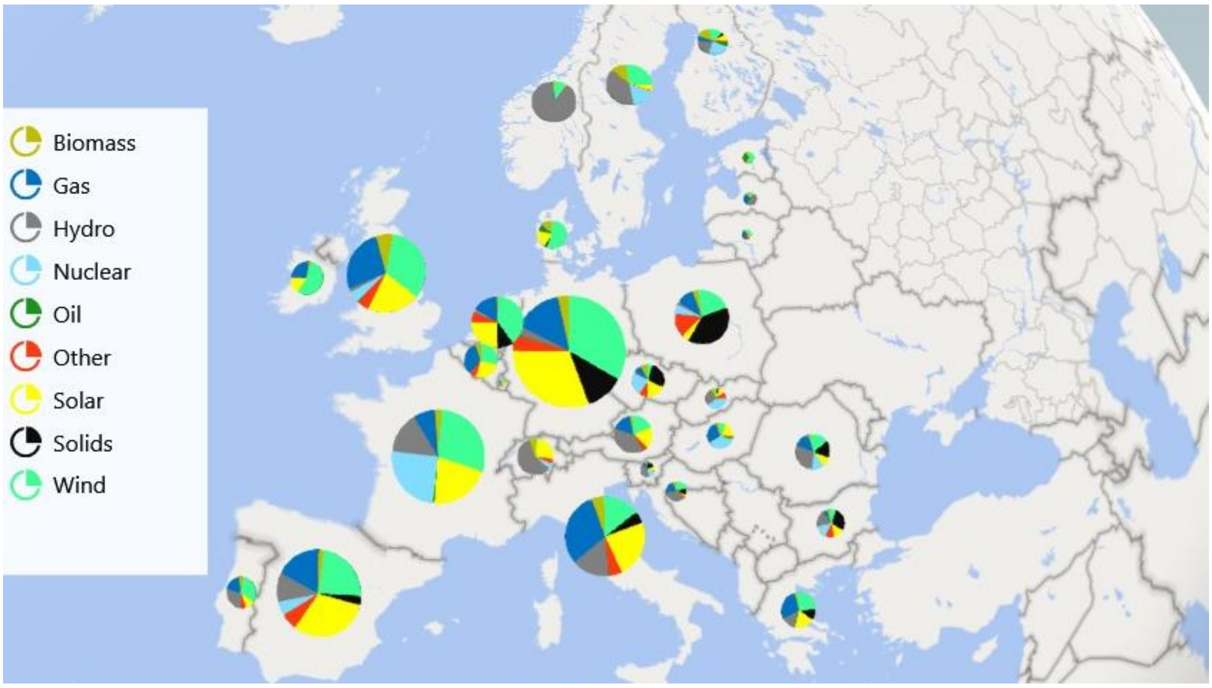


Figure I-7: EU wide power system portfolios considered in this analysis. Portfolios and interconnection capacities (except the All-Island System) are from ENTSO-E 2018 TYNDP

I.4.2 Pan European Model Development

Due to differing political, economic, social and technology drivers in Northern Ireland and Ireland, there are no unified official policy scenarios across both jurisdictions. A large number of published studies exist in the public domain with various projected portfolio for the year 2030. Some studies, like the Government of Ireland Climate Action Plan, do not present an All-Island overview.

Figure I-8: Studies considered for 2030 analysis

The EU SysFlex project is a Horizon 2020 project with a wide range of European partners including EirGrid and SONI. Part of the work thus far involved the analysis of system stability for the All-Island power system for the year 2030. Our analysis follows a similar make-up in

2030 conventional portfolio to the EU SysFlex study [258] with modifications to remove generators that were not in use. The resulting 2030 portfolio is compared to the existing 2020 All-Island system in Figure I-9. The portfolio was checked to be in line with the current All-Island loss of load expectation (LOLE) standard of 8 hours and all scenarios are tested for robustness to ensure adequacy of supply across multiple weather years.

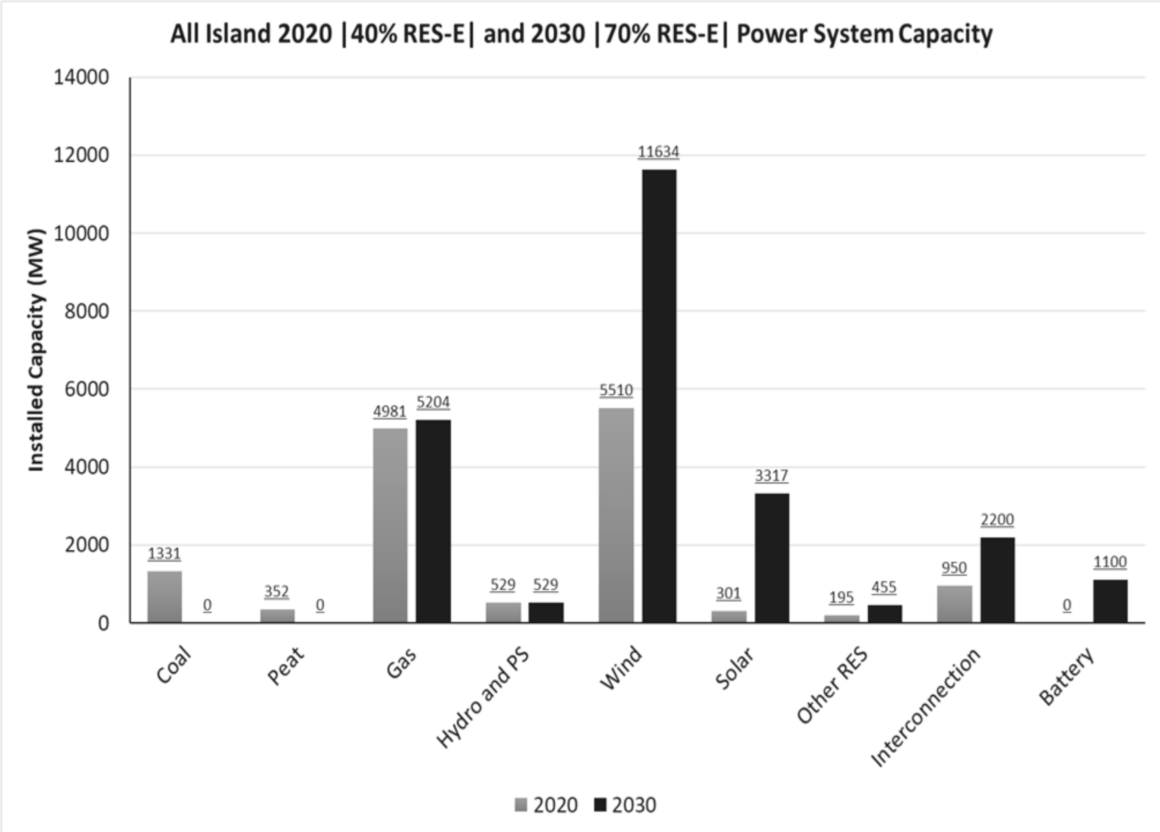
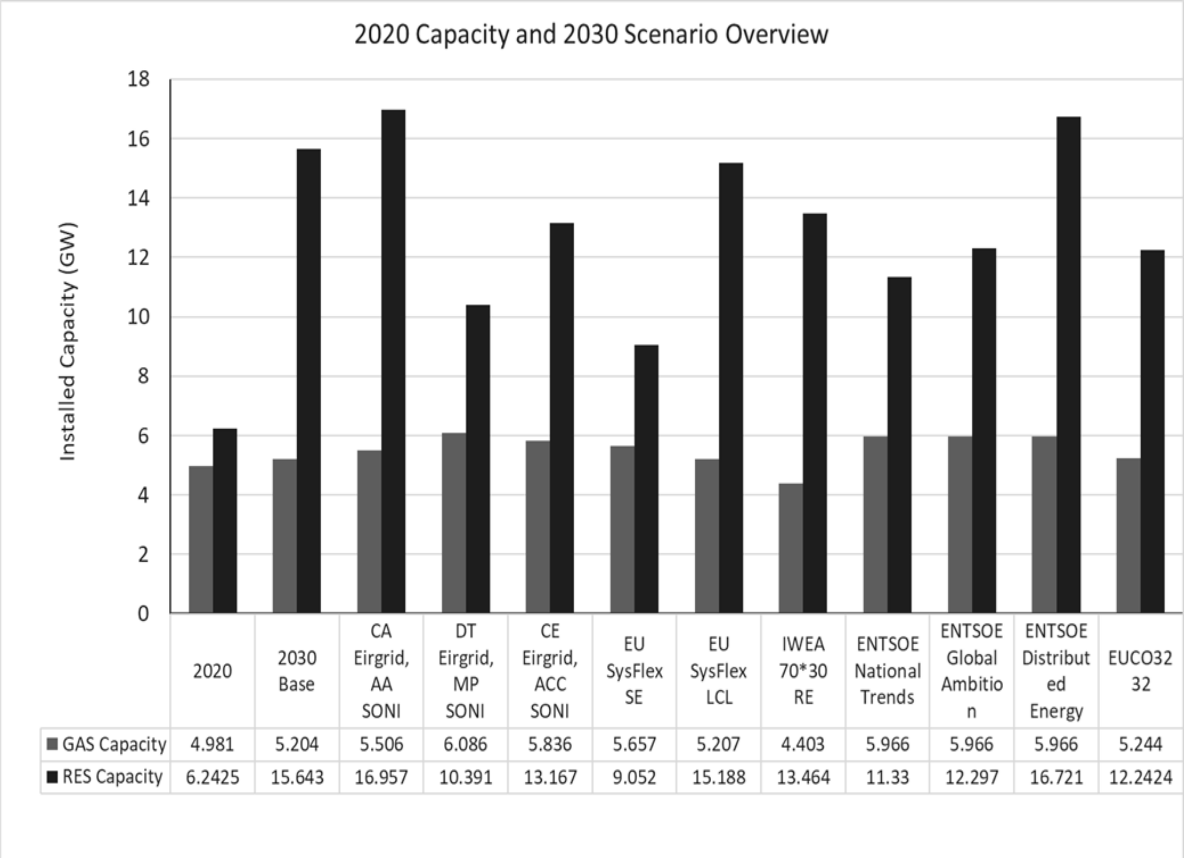


Figure I-9: Comparison of 2020 and 2030 All-Island Power System portfolio

The resulting portfolio is also compared to other published studies from SONI and EirGrid, ENTSO-E, IWEA and the European Commission for the All-Island system for context in Figure I-10. There is a consensus across studies that significant levels of gas fired generation will be required.



	2020	2030 Base	CA Eirgrid, AA SONI	DT Eirgrid, MP SONI	CE Eirgrid, ACC SONI	EU SysFlex SE	EU SysFlex LCL	IWEA 70*30 RE	ENTSOE National Trends	ENTSOE Global Ambition	ENTSOE Distributed Energy	EUCO32 32
GAS Capacity	4.981	5.204	5.506	6.086	5.836	5.657	5.207	4.403	5.966	5.966	5.966	5.244
RES Capacity	6.2425	15.643	16.957	10.391	13.167	9.052	15.188	13.464	11.33	12.297	16.721	12.2424

Figure I-10: Comparison with other published studies and 2020 capacity. Our portfolio is the 2030 Base

In line with the findings of the EU SysFlex study [258], it has been assumed in this study that the FFR requirement is 100% of the largest single infeed (generator or interconnector import) as is Primary Operating Reserve (POR). SOR, TOR1, TOR2 are assumed to remain the same as they are at present. All batteries are considered for reserve and energy.

I.4.3 Heat and EV Profiles

One of the recommendations by the Committee on Climate Change [259] concerning heat decarbonisation in Northern Ireland is to replace oil heating in the off-gas grid area with low carbon heat supply, mainly heat pumps. The main energy policy document for Northern Ireland, Strategic Energy Framework (SEF 2010-2020) set a target of 40% of electricity consumption and 10% of heat supply from renewables by 2020 [252]. By June 2020, Northern Ireland had exceeded the 2020 electricity target, however, the goal for renewable heating will most likely not be achieved[9]. Similarly, in Ireland, the Climate Action Plan sets ambitious goals

[9] A recent overview of heating in Northern Ireland by Ulster University can be found in [260].

for the deployment of heat pumps in the residential sectors and these are included in the analysis as extra loads on the electricity system.

There is currently limited public availability of annual electric vehicle charging profiles that are based on actual charger use. To model the impact of the deployment of electric vehicles on the All-Island system we use normalized hourly charging demand profiles which consider residential, work, slow/fast public and rapid public charging from National Grid UK. In the analysis we assume that 75% of EVs are charged at home, 15% at work and the remainder is split between slow and fast charging.

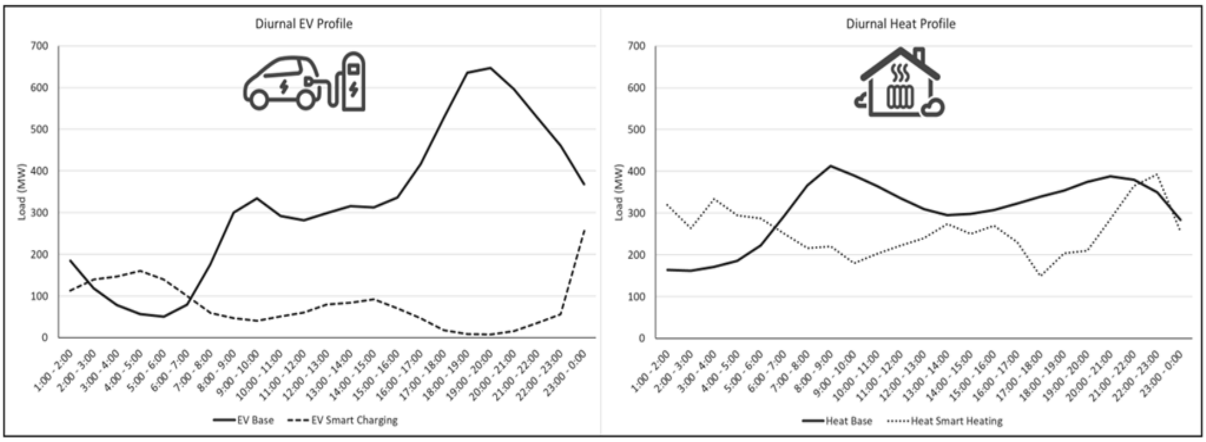
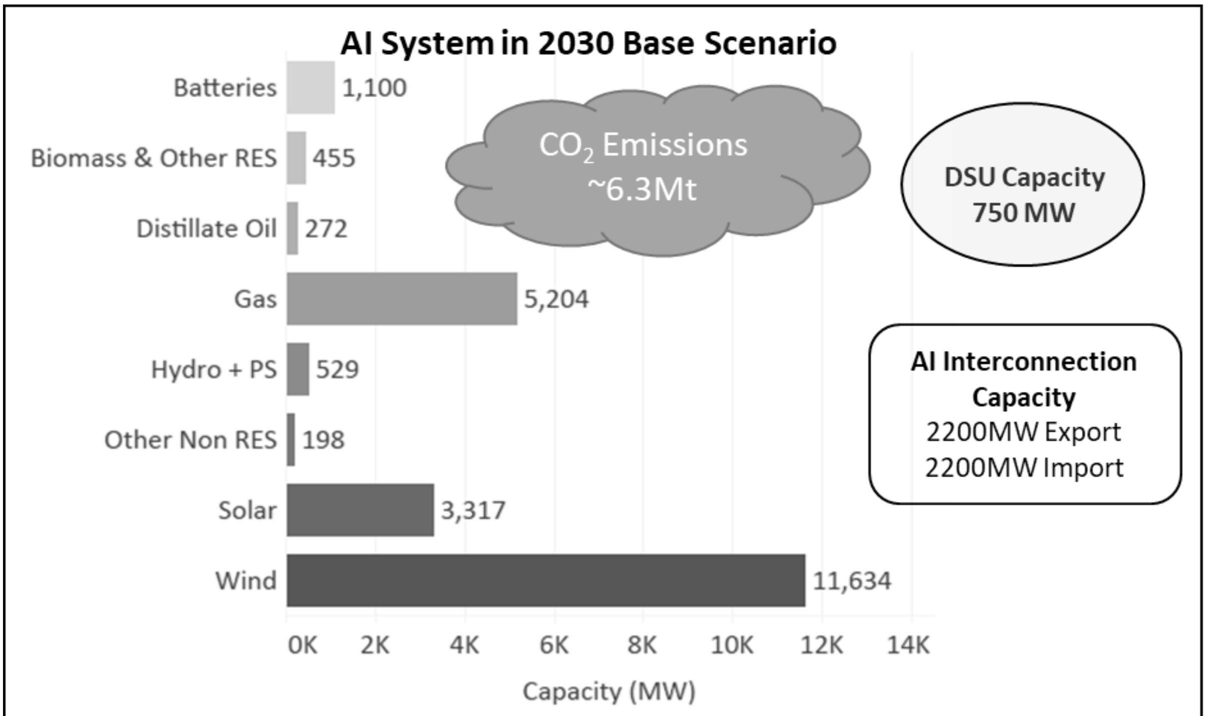


Figure I-11: Diurnal EV and Heating profiles used in the study

To model the impact of smart charging and smart meters for home heating and home EV charging use, we assume that 20% of the gross daily load is 'smart' and movable to hours in the day where the overall costs of the system is lowest. The resulting smart profiles are also shown in Figure I-11 as dashed lines. Note that these are an output rather than an input to the model.

I.4.4 Core Scenarios and Narratives

2030 Base: This is the core scenario which assumes the All-Island System meets a 72% renewable electricity ambition. We assume Northern Ireland hits a 73% RES-E target and Ireland meets its 70% RES-E target. In developing renewable portfolios, we add variable renewable capacity such as wind and solar to the system until the level of ambition is reached and then iteratively adjust battery storage capacity to limit the overall level of variable renewable curtailment to ~7%. The values we use are indicative only and the exact level of offshore wind, onshore wind, solar and other renewable technology will be determined by competitive auctions and technology development. The renewable portfolios are 'frozen' for all scenarios unless specifically stated. All scenarios assume 750MW of demand side response units.



AI Demand 53.7 TWh	1,000,000 EVs 750,000 ASHP	**Smart Moveable Load** 20%
Min Inertia Level None	**Min No of Synchronous Generators ('Min Units')** 4	**SNSP Limit** 95%
AI RES Target 72%	**No local constraints**	**VRE Curtailment** ~7%

Figure I-12: Overview of 2030 Base scenario

Lower Flexibility: This scenario explores the importance of flexibility in the system and we deliberately model a SNSP limit of 75% within a system that is inherently less flexible than the 2030 Base Scenario. The generation portfolio is the same as the 2030 Base Scenario.

	Min Inertia Level	Min No of Synchronous Generators ('Min Units')	SNSP Limit
2030 Base	None	4	95%
Lower Flexibility	17,500 MWs	6	75%

Table I-1: Differences between Lower Flexibility Scenario and 2030 Base Scenario

Lower Electrification: In this scenario, we explore the relationship between the electricity system and wider energy system decarbonisation and in particular we model a 20% reduction in the uptake of electric vehicles and heat pumps.

2030 Base	1,000,000 EVs	750,000 ASHP
Lower Electrification	800,000 EVs	600,000 ASHP

Figure I-13: Differences between Lower Electrification scenario and 2030 Base Scenario

Weather Years Scenario: We undertake a 'Dunkelflaute' analysis (cold and calm snap) where we simulate a large number of historic weather years to understand how the electricity system operates in long periods of cold and calm weather.

Within each scenario a number of sensitivities are introduced to determine specific impacts around the 2030 Base Scenario. These sensitivities include:

1) An increase in wind capacity
2) Removal of Min Units constraint on All-Island System
3) Increased levels of 'smartness' (i.e., flexibility) in EV and Heating loads
4) The impact of a Carbon Capture and Storage (CCS) plant on All-Island emissions
5) The impact of varying generation portfolios in France and the UK

	2030 Base	Lower Flexibility	Lower Electrification	Weather Years
All-Island Electricity Demand (TWh) Includes HP and EVs	53.7	53.7	53.7*	53.7*
Interconnection (MW)	2200	2200	2200	2200
% All-Island RES-E Target	72	72*	72*	72*
% SNSP Limit	95	75	95	95
Min Inertia (GWs)	None	17.5	None	None
Min units required online	4	6	4	4
Electrification of heat and transport	1 million EVs 750k ASHP[10]	1 million EVs 750k ASHP	0.8 million EVs 600k ASHP	1 million EVs 750k ASHP
Wind Power (GW)	11.6	11.6	11.6	11.6
Solar Power (GW)	3.3	3.3	3.3	3.3

Table I-2: Core Scenarios

*some values will vary with scenario and sensitivity.

[10] ASHP refers to Air Source Heat Pump

I.4.5 Constraints and Curtailment

The current All-Island system has a number of system wide constraints. When a system wide constraint restricts the output of a generator or group of generators it is known as curtailment. When the output restriction is caused by a local network issue where the physical infrastructure of the grid cannot accommodate all the generation it is a local constraint. In 2019, the combined amount of curtailment and constraint (also known as dispatch down) for the All-Island power system was 7.7% with 4% attributed to constraints and 3.7% attributed to curtailment [261]. In this study, local constraints are not considered and only system wide constraints (i.e., curtailment) are examined. This includes reserve provision in addition to the other constraints such as SNSP, Min Units and min inertia and are specified in Table I-2. Other EirGrid/SONI operational policies are not included. Where there is no inertia constraint prescribed it is assumed that inertia is provided from other sources such as synchronous condensers and/or new technologies. These were not explicitly modelled.

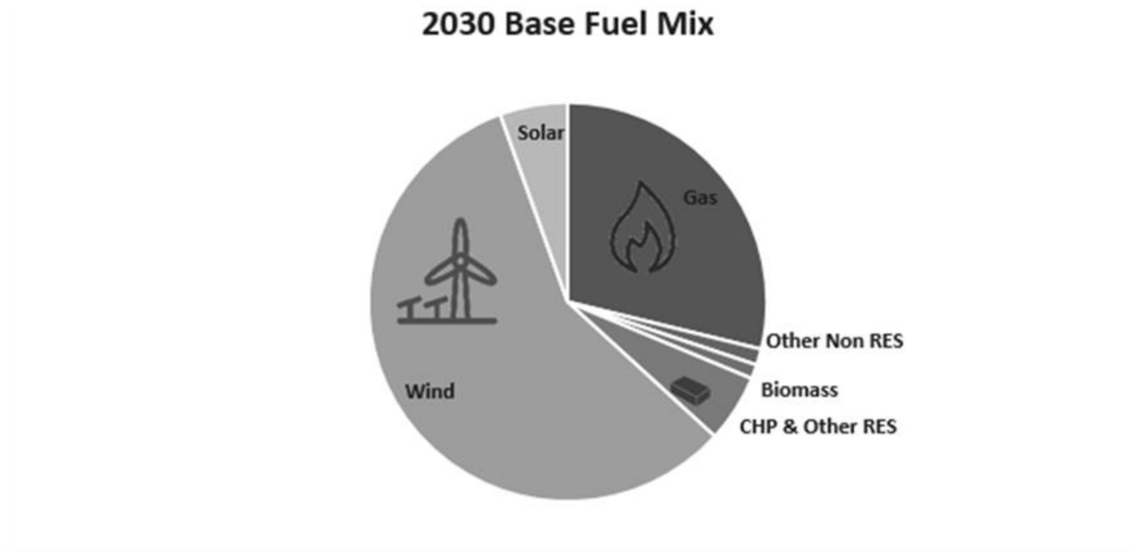
I.5 Results and Discussion

High level results for each scenario are introduced followed by a comparison of scenarios and insights from individual sensitivities.

Key messages:

- **Achieving a high RES-E ambition across the All-Island system requires the SNSP to increase to over 85%, grid constraints removed and continued investment in flexibility and infrastructure. Without this, emissions will increase.**
- **Conventional generation plays a necessary role in generation, system services and flexibility. The required Gas fired capacity is similar to today but will run for fewer hours and produce less energy.**
- **Electrification of new loads in heat and transport play an important role in wider system decarbonisation. Slower uptake on technologies such as heat pumps and electric vehicles may reduce power system emissions but has a net increase on energy system emissions.**

The modelled 2030 system is different in scale and configuration from the system we see on the Island today. Despite the expected retirement of some generators, the system is 60% larger in capacity. In 2030, the All-Island system is essentially a dual fuel system (natural gas and wind). However, smaller elements of other renewables play an important role in offering technology diversity. A significant driver of decarbonisation is not only the increase in renewable generation, but also the exclusion of peat and coal from the fuel mix. These units typically met up to 15% of generated power and accounted for up to 40% of emissions (2018 figures). In the scenarios, we assume that 1 of the peat generation is fired on 100% sustainable biomass in 2030 and this contributes 2 percentage points to the RES-E ambition and reduces emissions by 0.25kt CO_2eq. Other renewable elements include existing hydro, landfill gas, combined heat and power with biomass and the biodegradable portion (50%) of waste from waste to energy plants.



Sources				
Coal	Gas	Peat	Var Renewable	Other RES
0%	30%	0%	63%	7%
% Change from 2019				
-100%	-20%	-100%	160%	180%

Figure I-14: 2030 Base Scenario Fuel Mix and comparison to 2019 system

I.5.1 2030 Base Scenario

The 2030 Base scenario achieves a 72% target across the system and sees a significant reduction in CO_2 emissions, reducing from an estimated 13.0 Mt in 2018 to 6.3 Mt in 2030 giving a carbon intensity of electricity generated of 118 gCO_2/kWh. Variable renewable curtailment is 7.1% for the year. Achieving the RES ambition requires significant flexibility and improvement in grid infrastructure across the system. In this scenario, all grid constraints are removed, the second North-South tie line is in full operation and an SNSP level of 95% is assumed by 2030.

Conventional generation plays a necessary role in generation, system services and flexibility. The system has a similar level of gas capacity to today’s system (circa 5.2GW), but these generators will operate at reduced levels. While there is a significant increase in renewable ambition across the island, the level of energy produced by gas fired generation reduces by 20% relative to 2019 (or ~ 4 TWh less). highlighting the importance of gas and associated delivery infrastructure to the system. Gas generators will operate in a technically and economically more challenging environment with more ramping events and longer hours at minimum generation. In the modelled scenario, CCGTs[11] operate for an average of 6,000 hours per year with 23% of these hours at minimum generation and averaging at ~70 starts per year. It should be noted that only ‘generic’ CCGT are modelled, and individual generator characteristic will cause this to vary. OCGTs[12] on the other hand will operate at much lower levels but provide important capacity at times of system stress when weather driven generation is low and interconnector flows are limited. Average running hours across the fleet

> What drives the level of Gas Fired Generation in 2030?
>
> It might seem unexpected that such a significant increase in renewable generation results in a relatively modest reduction in electricity generated from natural gas (20%). The key here is understanding the interaction between electricity demand and renewable targets.
>
> In general, renewable targets are a poor proxy for overall emissions reduction because they don’t capture the impact of increasing or decreasing energy demand. In 2030, over 70% of annual electricity must come from renewables such as wind, solar, hydro and biomass. This means that 30% of electricity load is met by gas fired generation, however this is 30% of an electricity load that is bigger than today. EirGrid estimate total electricity demand over the next ten years is forecast to grow by between 19% and 50%, largely driven by new large users, many of which are data centers. In our analysis, we assume electricity demand is 33% larger than today driven in part by electrification of new loads such as electric cars and electric heating (accounting for 50% of the increase) and new loads from Data Centres (the remaining 50% of the increase). The net impact of increased renewable ambition and increased growth in demand is a modest reduction in overall thermal generation.

is approximately 87 hours with ~60% of these hours at minimum generation.

Battery and other storage play an important role in absorbing weather driven variability. Batteries provide benefits in terms of reserve provisions, storage and reduce ramping across the system. Batteries operate at an annual capacity factor of approximately 16%.

I.5.2 Lower Flexibility Scenario

With lower levels of system flexibility, we are unable to reach a RES-E ambition of 70%. It results in a level of 66% RES-E but with significant levels of variable curtailment (16%) making

[11] Combined Cycle Gas Turbine
[12] Open Cycle Gas Turbine

the financing of renewable projects highly challenging. All-Island emissions are 7.2 Mt, 14% higher than the 2030 Base Scenario. In this analysis, we find that an SNSP level of at least 85% across the Island must be achieved to meet a RES ambition of at least 70%.

I.5.3 Lower Electrification Scenario

We model a lower uptake of EVs and Heat Pumps (200,000 less EVs and 150,000 less ASHPs) in the All-Island System in 2030. Lower uptake of EVs and Heat Pumps naturally leads to a lower electricity demand and results in lower emissions of 0.1 Mt in the electricity system. However, the resulting emissions in the wider energy system are higher by 0.9 Mt[13]. The net system wide impact is that these lower levels of electrification lead to a net increase of 0.8Mt.

From a climate policy perspective, the impact is more nuanced for Ireland as it has obligations to reduce emissions in the non-ETS sectors by 30% relative to 2005. The impact on Ireland's Non-ETS targets are the gross emissions (rather than net) as once new loads are electrified, they transfer to the ETS sector regardless of whether net emissions are lower or not.

	2030 Base	**Lower Flexibility**	**Lower Electrification**
All-Island RES-E (%)	72%	66%	73%
CO_2 Emissions (Megatonnes)	6.3	7.2	6.2[14]
Carbon Intensity (g/kWh)	118	135	115
Variable RES Curtailment	7%	16%	8%
Conventional Gas Generation (GWh)	15942	18117	15471
Wind and Solar Generation (GWh)	34971	32008	34742
Other Generation (GWh)	4403	4377	4397
Average Running hours per CCGT	5971	7279	5825
Average Hours at Minimum per CCGT	1390	2449	1349
Net Exports from All-Island	1344	2780	2055

Table I-3: Overview of Main Scenarios

[13] The underlying assumptions here are that an ASHP replaces an oil-fired boiler (3.5t CO_2) and an EV replaces a petrol car (1.8t CO_2).

[14] The energy system wide impact is a net increase of 0.8Mt.

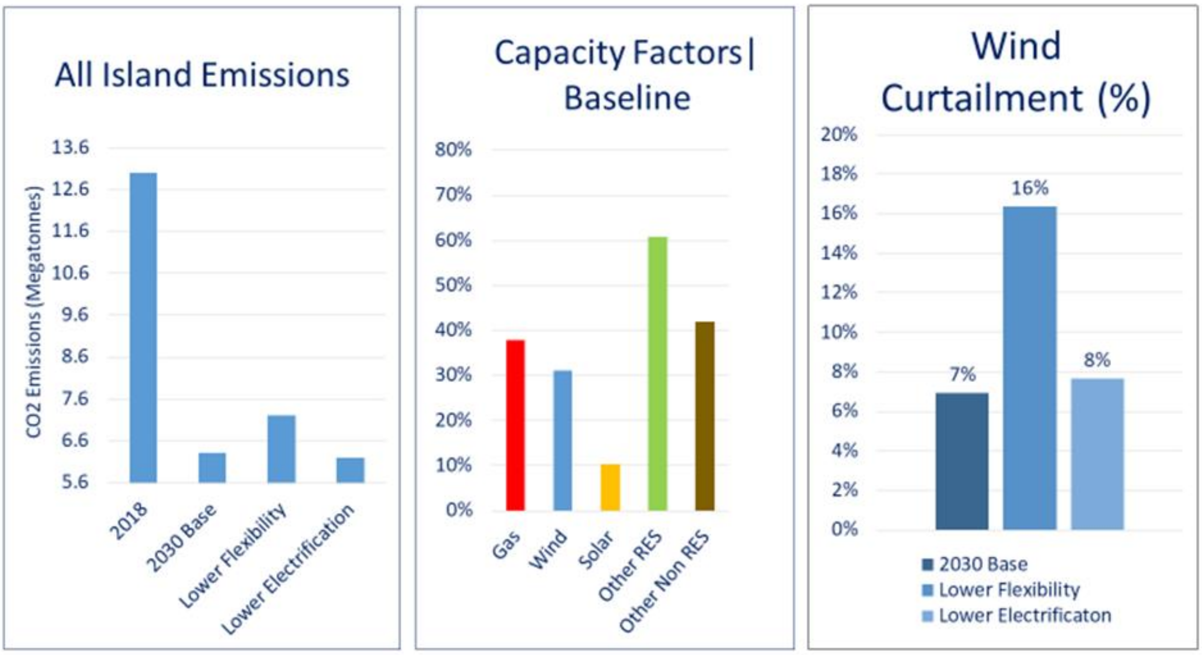


Figure I-15: CO_2 Emissions, Capacity Factors and wind curtailment for presented scenarios

I.5.4 Weather Years Scenario

The so called “Kalte Dunkelflaute” (German for “cold dark doldrums”) describes an extended period with very low outside temperature as well as low production of wind and solar energy. This weather phenomenon is frequently seen, e.g., in Germany from 16 to 26 January 2017, with up to 90% of the generation coming from conventional power generators at peak demand. With higher electrification of final demand sectors, especially the residential and tertiary sector, and high penetration of renewables in the power market, the “Kalte Dunkelflaute” becomes an important security of supply test for an evolving energy system. In this analysis, we simulate the EU Wide Power System with over 250,000 hours of weather data (30 years) to examine how the All-Island System operates during 2-week periods of low generation from wind and solar.

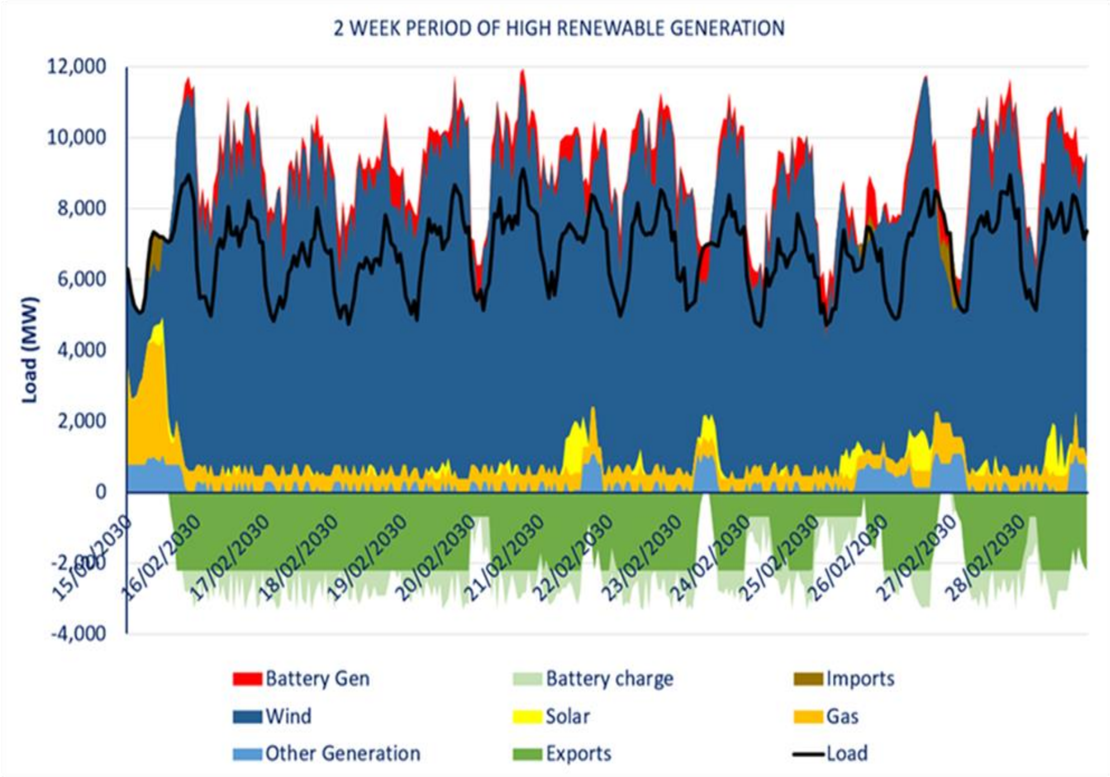
In general, across the island of Ireland Atlantic low-pressure systems are well established in our weather systems by December, and depressions move rapidly eastward in December and January, bringing strong winds with rainfall. Occasionally a cold anticyclone over the UK and Europe extends its influence westwards to Ireland, giving dry cold periods lasting several days. Very cold winter temperatures accompanied by low wind speeds are often attributed to persistent high-pressure systems over the British Isles, described as a ‘low wind cold snap’. Cradden *et al*., examined the prolonged cold spells which were experienced across the island of Ireland in the winters of 2009–10 and 2010–11. While electricity demand was relatively high at these times, wind generation capacity factors were low. It was highlighted that there is still a significant level of variation in results within individual seasons and indicated there was merit to identifying the potential for more unusual extreme events in each season [262].

While these occurrences are infrequent, they profoundly impact the design of a robust and reliable electricity system, not only for the All-Island system but for the wider north western European region as they tend to impact a wider geographic region which has knock on consequences for flows on interconnectors.

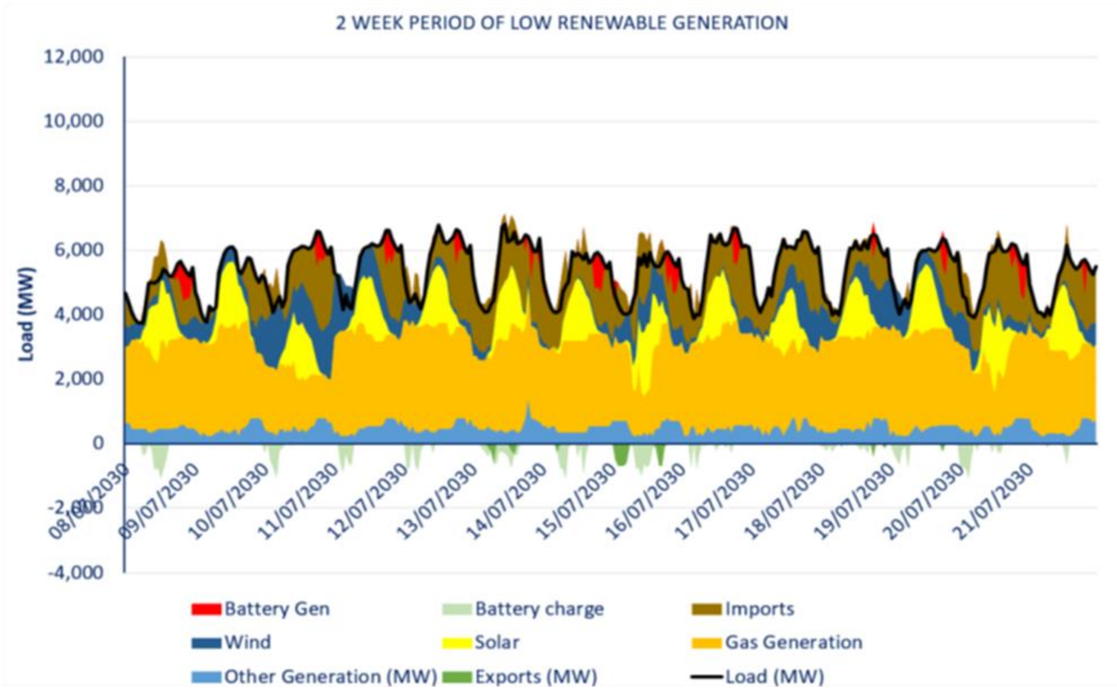
In this analysis, we examine 30 historical years of hourly European weather data and simulate the full system with individual weather years. In particular, we focus on 4 specific events all over 2-week periods: A) maximum generation of variable renewables. B) minimum generation of variable renewables. C) highest generation of conventional gas fleet and D) period with lowest capacity margin.

The analysis highlights how remarkably flexible the All-Island system will have to be to deal with a wide and extreme variation in weather events. At times the system will produce more renewable generation (Pane A) than can be used, stored or exported, while it must also be resilient and reliable to deal with periods (Pane C) when gas, conventional generators and interconnectors will provide the bulk of weekly generation and demand side response units and batteries help on shorter timescales. There will also be short periods of system stress where all available conventional generation is called upon (Pane D) to ensure supply is met.

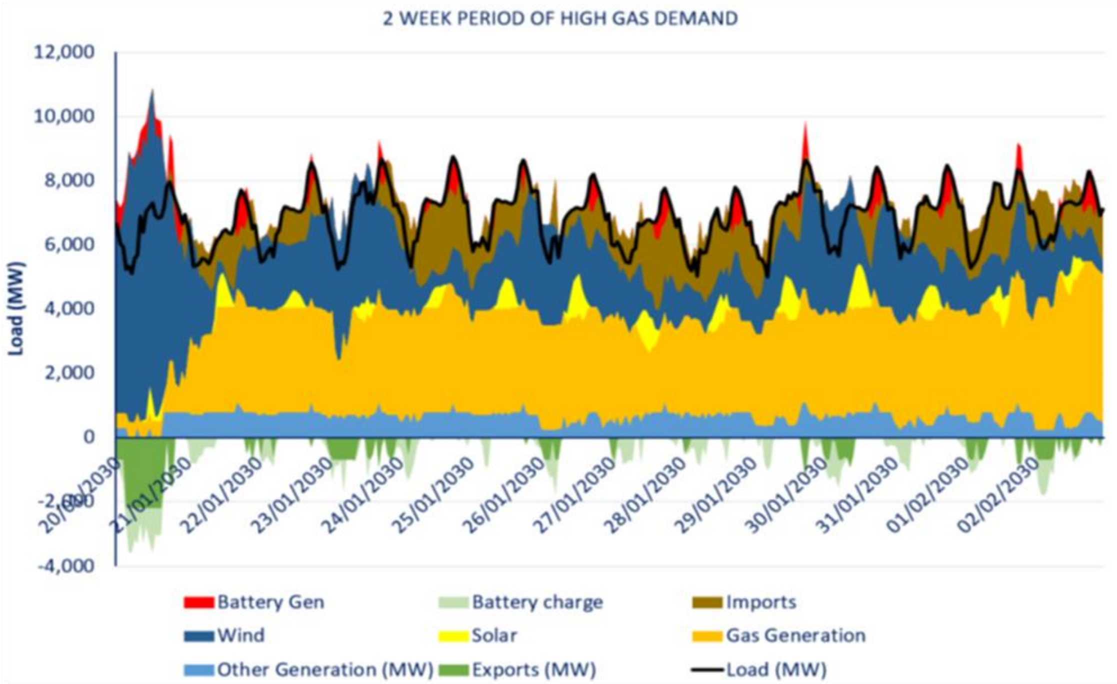
A


2 WEEK PERIOD OF HIGH RENEWABLE GENERATION
Load (MW)
12,000
10,000
8,000
6,000
4,000
2,000
0
-2,000
-4,000
15/02/2030
16/02/2030
17/02/2030
18/02/2030
19/02/2030
20/02/2030
21/02/2030
22/02/2030
23/02/2030
24/02/2030
25/02/2030
26/02/2030
27/02/2030
28/02/2030
Battery Gen
Battery charge
Imports
Wind
Solar
Gas
Other Generation
Exports
Load

B


2 WEEK PERIOD OF LOW RENEWABLE GENERATION
Load (MW)
12,000
10,000
8,000
6,000
4,000
2,000
0
-2,000
-4,000
08/07/2030
09/07/2030
10/07/2030
11/07/2030
12/07/2030
13/07/2030
14/07/2030
15/07/2030
16/07/2030
17/07/2030
18/07/2030
19/07/2030
20/07/2030
21/07/2030
Battery Gen
Battery charge
Imports
Wind
Solar
Gas Generation
Other Generation (MW)
Exports (MW)
Load (MW)

C



D

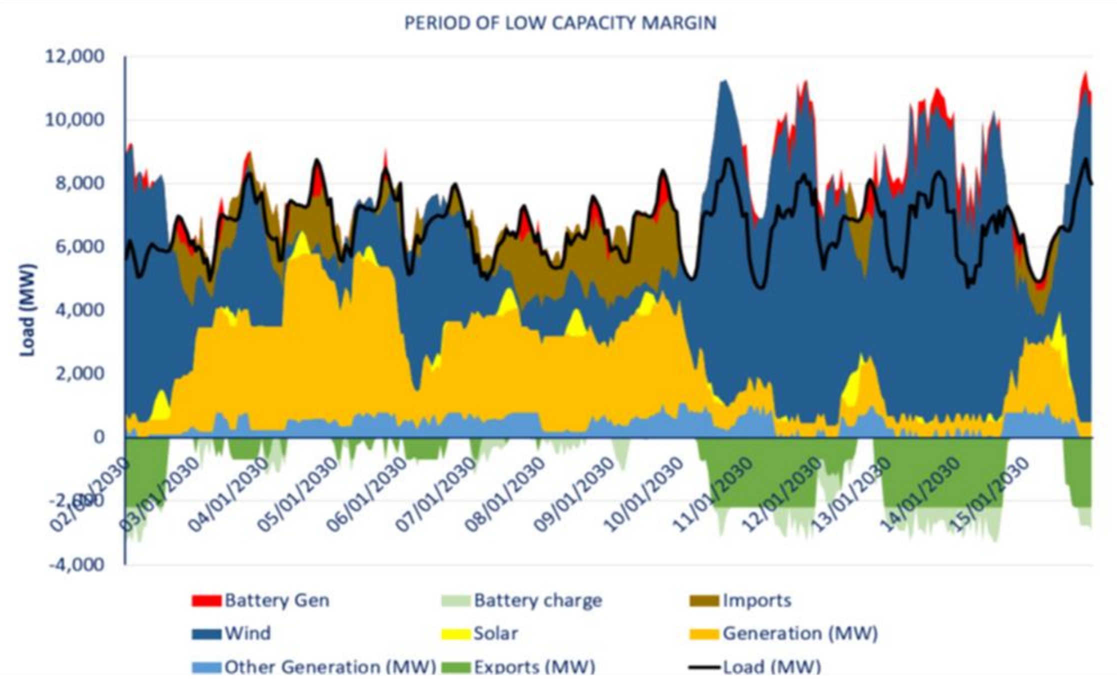


Figure I-16: Weather Years Scenario: A) High wind period, B) Low wind period, C) High gas generation period and D) Low capacity margin.

Dealing with prolonged periods of low weather driven generation in the All-Island system is not trivial, and while conceptual solutions involving batteries, large scale storage and increased interconnection are appealing, the issue is not an easy one to solve.

A challenge with using electrical storage, such as batteries, in conjunction with weather driven renewable generation is the scale required to store enough energy for a prolonged period with low weather availability. Storage technologies such as batteries have many uses over short time scales and can provide important services to the grid, but current technologies cannot economically provide the scale of capacity to operate an electricity system on variable renewable generation alone. For example, if we consider the 2-week window of low wind speeds in Pane C, approximately 65 million Tesla Power walls (assuming 13.5kWh per unit) would be required to provide energy for this period.

We also examine the role of interconnectors and in particular we focus on the direction of flows in terms of export and import to the All-Island system at individual hours of the days across the sample of 30 years of weather data.

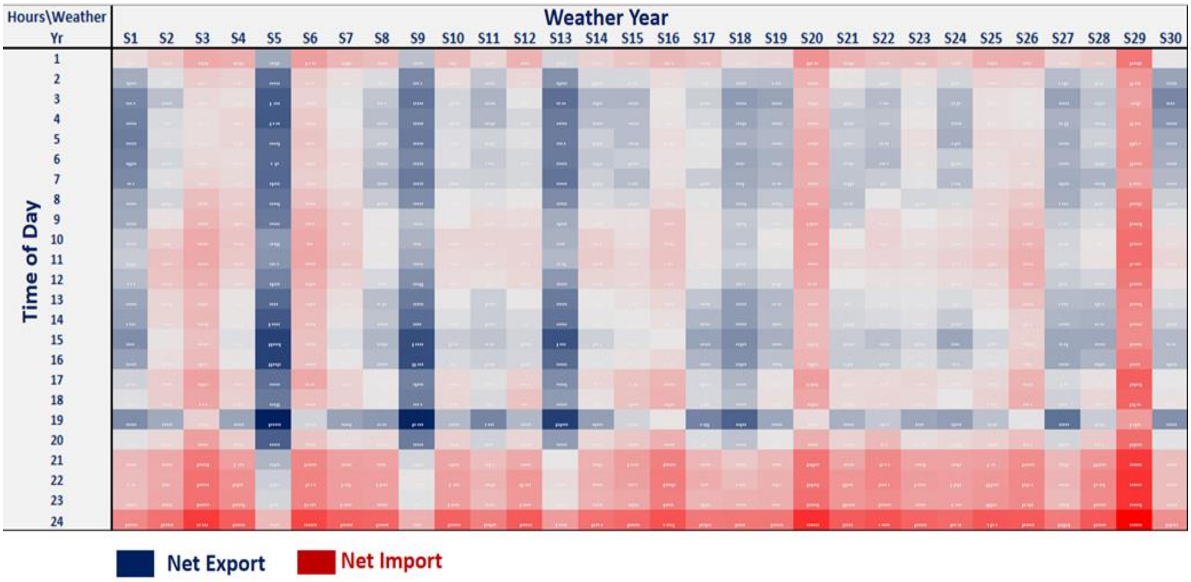


Figure I-17: Average hourly direction on interconnector flows for hours of the day (y-axis) and 30 different weather years (x-axis). The stronger the colour (blue or red) the larger the magnitude of flow.

The analysis of interconnector flow shows that an individual weather year has an important impact on the direction of flow (net import or net export) and magnitude of flow. On balance the All-Island system is a net exporter of power, but low wind years change this (for example S29). It can also be seen that at time of peak demand (18:00) the flow on the interconnector is again influenced by the overall weather year.

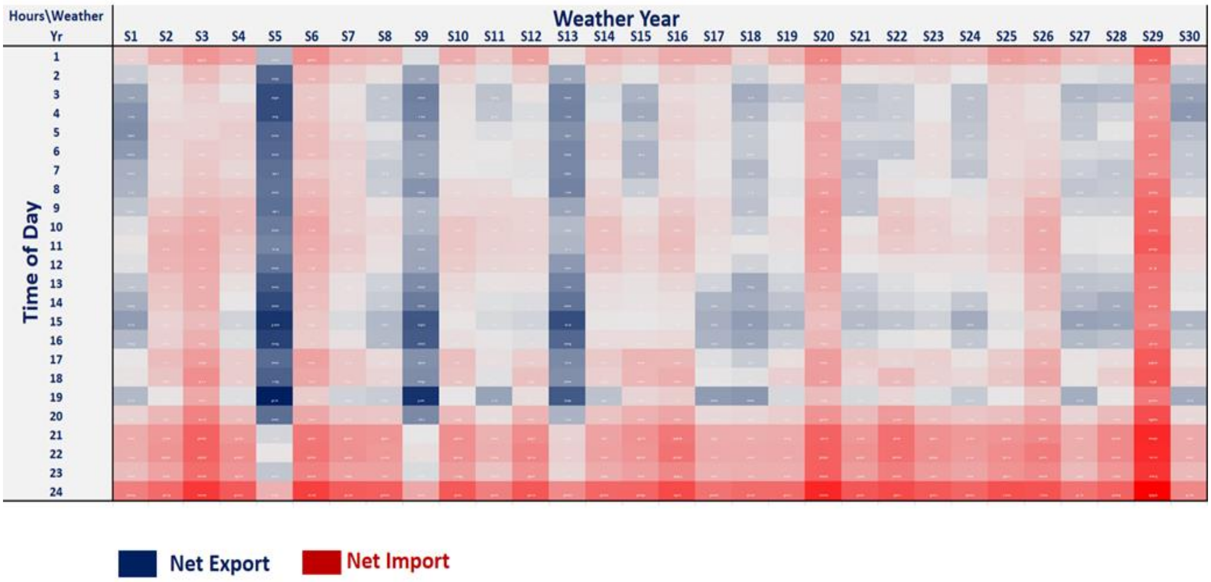


Figure I-18: Sensitivity on average hourly direction on interconnector flows for hours of the day (y-axis) and 30 different weather years (x-axis). The stronger the color (blue or red) the larger the magnitude of flow. In this scenario GB and UK have 10% more wind

A further scenario was considered (above) where the level of wind capacity in France and Great Britain was increased by 10%. The impact of this change was the increase the overall level of net import into the All-Island system and decrease the overall net exports. However, the dominant driver of net interchanges was the weather year with overall hourly flows seeing smaller changes.

I.5.5 Sensitivities

The following sensitivities are considered in the next section:

1) Removal of Minimum Units (Min Units) constraint on All-Island System
2) An increase in wind capacity
3) Increased levels of 'smartness' in EV and Heating loads
4) The impact of a CCS plant on All-Island Emissions and
5) The impact of varying generation portfolios in France and the UK

Note: In all sensitivities the 2030 Base Scenario portfolio remains static.

I.5.6 Removal of Min Units constraint on the All-Island System

To enable the secure and reliable operation of the All-Island power system the system operator needs to apply some operational constraints. In 2020, this means that a number of conventional generators in various locations are required to run to assist the system with inertia, voltage stability, reserve and other technical elements. For 2030 we have assumed that some of these operational constraints are required, including a requirement for a minimum number of generation units referred to as the Min Units constraint. Within the scenarios modelled for 2030, curtailment of weather driven generation is largely influenced by system constraints such as Min Units and the SNSP limit. With substantial renewable capacity additions required to achieve 2030 targets, there is likely to be continued stress on curtailment unless steps are taken to relieve these constraints. We assume a Min Units constraint of 4 units (unless stated) across the system, and in this sensitivity, we remove the constraint to understand the impact on emissions and the system.

While Ireland is leading the world in research in this area, it is not yet clear what the cost and technical implications would be of removing this constraint. Investment would likely be needed in synchronous condensers, flywheel storage, or novel synthetic inertia schemes needed for scenarios where conventional generation is not meeting the inertia constraint to maintain ROCOF at 1Hz/s. Therefore, this sensitivity should be seen as a contribution to the conceptual understanding of outcomes rather than a clear indication of what will happen.

Removing the Min Units constraint of 4 units in the 2030 Base Scenario reduces All-Island emissions by 0.8Mt (6.3Mt → 5.5Mt) and reduces variable renewable curtailment to 5.8%. The impact on conventional generation is significant with average annual running hours for a CCGT reducing from nearly 6,000 hours to just over 4,300 hours with 10% of these hours at minimum level.

I.5.7 Increased wind capacity

This sensitivity explicitly explores increased wind capacity levels from the 2030 Base scenario. This scenario fully incorporates the Irish government's plan to deploy up to 5GW of offshore wind by 2030. To limit curtailment a subsequent increase in battery capacity from 1.1GW to 3.5GW and an increase in interconnection capacity from a base case of 2.2GW to 5.0GW is required. The gas capacity remains the same as the base case to ensure that demand can be met during periods of system stress or low wind generation.

The increase in wind capacity makes a strong contribution to the All-Island renewable energy level from 72% to approximately 97% and the associated emissions reduction is ~1.3Mt from the 2030 Base scenario. This scenario sees significant exports of power and presents a challenge for policy makers as it highlights a divergence in outcomes between renewable energy policy and decarbonisation policy. In the absence of a cooperation mechanism which accounts for providing decarbonized electricity to other countries, the All-Island system will only realize marginal carbon reduction benefits of being a major exporter of power.

The increased wind capacity has an impact on the conventional generation fleet, reducing annual average operating hours from approximately 6,000 hours to approximately 5,100 hours with 27% of this time at minimum generation. A further sensitivity was undertaken where in addition to the extra wind capacity the full relaxation of the Min Units requirement for 4 units is also assumed thus simulating a remarkably flexible system. In this ambitious sensitivity, All-Island emissions reduce to 3.4Mt (6.3Mt → 3.4Mt) and the average running hours for conventional generators (CCGT) reduce to below 2,600 hours. The average fleet wide capacity factor for conventional generators (CCGT and OCGT) is 30%, a reduction from the 40% capacity factor reported in 2019.

I.5.8 Increased levels of 'smartness' in EV and Heating loads

In this sensitivity, we examine the impact of increased levels of 'smartness' in demand side loads for residential heating and EVs. In the 2030 Base scenario, it is assumed that 20% of the daily demand is movable and within the optimization framework these loads are placed at periods of the day that lead to the most efficient operation of the systems in terms of costs and emissions. Constraints are applied, however, to reduce unrealistic outcomes such as a very high volume of a smart load in one-time period thus creating a significant ramp event within the system. In this sensitivity the level of smart load is assumed to increase to 40%. Results show that the impact is relatively small in terms of emissions reduction with a reduction of 0.1Mt relative to the 2030 Base Scenario.

I.5.9 The Impact of Carbon Capture and Storage plant on All-Island emissions

Carbon capture and storage (CCS) is a uniquely important technology that features strongly in global scenarios that achieve Net Zero emissions in line with the Paris Climate Agreement [263]. The Committee on Climate Change in the UK has recommended that carbon capture technology is investigated as a potential method for decarbonizing Northern Ireland's power sector and the Climate Action Plan in Ireland has established a Steering Group to examine and oversee the feasibility of the utilization of CCS in Ireland.

In this sensitivity, we assume that a gas fired generator is converted to CCS with a capture rate of 85% (a plant carbon intensity of approximately 60 gCO_2/kWh) and carbon is removed (post combustion) from the exhaust and injected deep below the ground, so it cannot enter the atmosphere and contribute to climate change. Results of the sensitivity indicate that All-Island emissions would reduce from the 2030 Base scenario of 6.3Mt to 5.2Mt. The impact on conventional power generators is relatively benign as the CCS plant is assumed to be a 'must run' unit and so overlaps with the Min Units requirement of 4 units to be online.

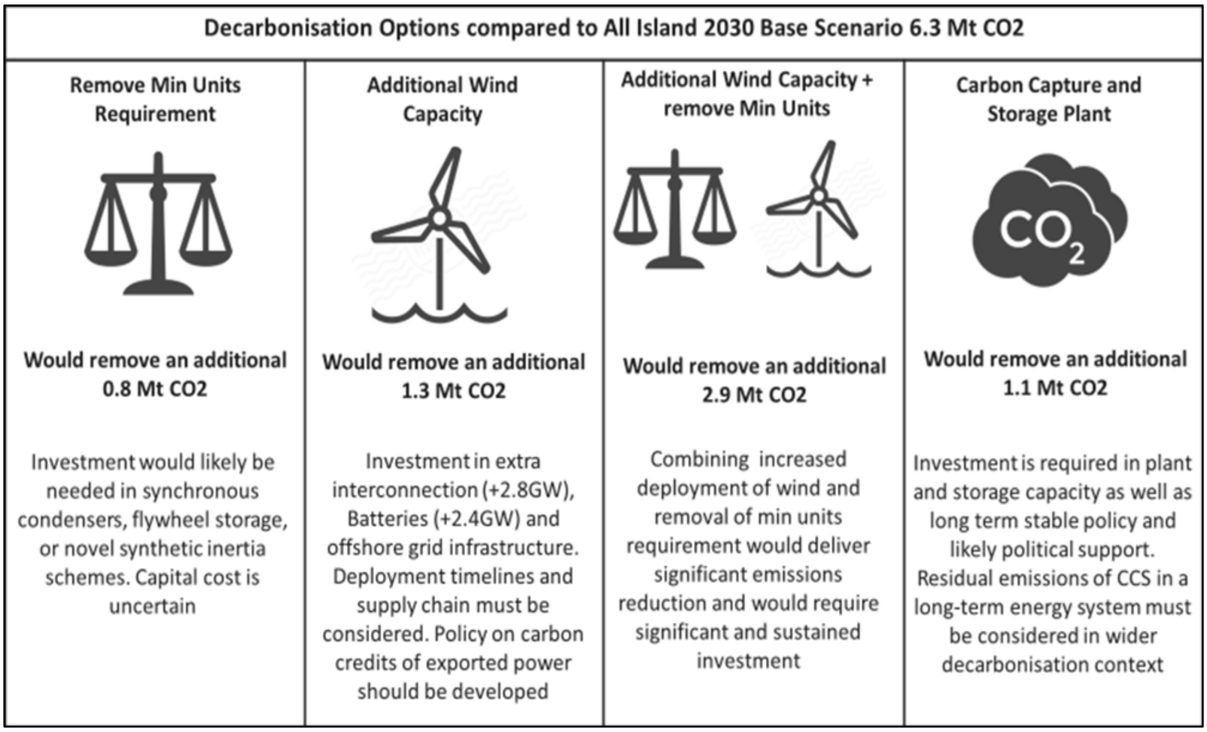


Figure I-19: Summary of decarbonisation options for sensitivities undertaken. Note that measures are not additive.

I.5.10 System Services

System services are required to ensure secure and reliable operation of the power system to the required standards. Such services include frequency response, reserve, system inertia and so on. Across all the 2030 scenarios we have assumed some level of advancement of technologies which leads to the relaxation of the SNSP and Min Units requirements from where they are today. This results in a reduction in run hours for conventional generation. It is inevitable that opportunities for conventional generation to gain income regularly from some system services will diminish with the reduction in run hours.

Figure I-20 shows the duration curves of available operating reserve[15] from conventional generation for the 2030 base scenario. This is significantly different to the situation in 2020 where a minimum level of these categories of operating reserve are always available from conventional generation. When the Min Units constraint is removed the available provision of these reserves from conventional generation reduces even further. The additional interconnectors to France and the UK, provide system service benefits in addition to the import/export potential. In 2030, batteries, interconnectors, and DSM[16] will dominate the provision of reserve in operating reserve categories such as Fast Frequency Response (FFR), Primary Operating Reserve (POR), Secondary Operating Reserve (SOR), Tertiary Operating Reserve 1 & 2 (TOR1 and TOR2).

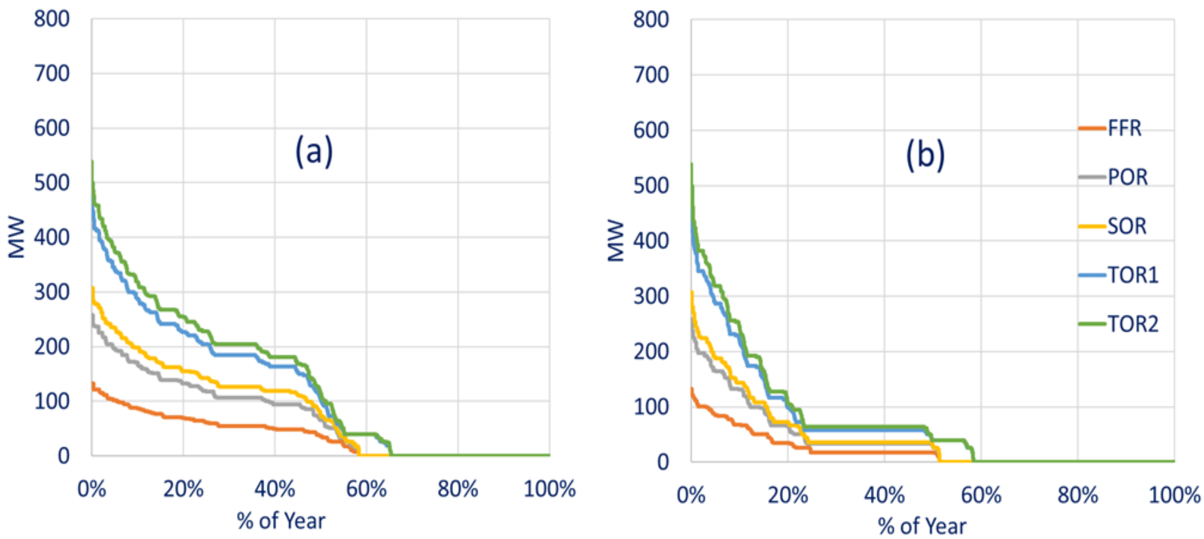


Figure I-20: Reserve available from conventional generation for (a) 2030 Base scenario and (b) 2030 Base scenario with Min Units constraint removed

Ramping margin is another type of system service. It is designed to ensure that the system is capable of coping with variability, particularly that caused by wind generation, and the risk that the levels of wind forecasted may be under or over estimated. There are currently 3 categories of ramping margin that have different time horizons and durations[17]. Conventional

[15] Operating reserve refers to additional power that is required following a system disturbance. The timeframe in which the Megawatts are delivered determines the category of reserve. FFR is provided between 2-10 seconds, POR between 5-15 seconds, SOR between 15-90 seconds, TOR1 between 90 seconds and 5 minutes, TOR2 between 5 – 20 minutes.

[16] Demand Side Management

[17] The system services Ramping Margin 1, 3, 8 refer to the increased megawatt output that can be delivered with a good degree of certainty for the given time frame of 1, 3 or 8 hours and maintained for a duration of 2, 5 or 8 hours respectively.

generation remains important year-round for the longer horizon ramping margin Ramping Margin 8, as battery technology is not expected to extend beyond a 4-hour storage duration by 2030.

The reduction in run hours for conventional generation also indicates that there will be less inertia and therefore less synchronous inertial response (SIR) available from conventional generators compared to 2020. However, the requirement to limit the rate of change of frequency (ROCOF) to 1Hz/s is not expected to be relaxed any further by 2030. Therefore, to reduce the Min Units requirement, additional low or zero carbon sources of inertia will be required. Proven technologies such as synchronous condensers and flywheel storage may form part of the solution, but new and innovative technologies will also be required. Appropriate market arrangements or incentives will be required to encourage investments in these technologies. The "Dunkelflaute" analysis demonstrated that conventional generation is still required in 2030 to provide generation and system services at times of system stress or low wind and so any market arrangements or incentives will have to be designed in a way that is mindful of this reality.

I.5.11 Expenditure and Investment Required

Significant investment must be made across both the power system and wider energy system in order to achieve ambitious levels of emissions reduction on the All-Island system. Here we estimate the 'overnight' investment required to achieve the level of emissions reduction presented in the 2030 Base scenario. Reaching this level of emissions reduction will require additional related expenditures of ~32€ billion. This is broken into the categories power plant such as wind turbines and solar panels, infrastructure such as electricity grid and non-grid system services costs in Figure I-21. Public data is available for the estimation of system services costs for the early years of the next decade. The methodology used to estimate the system services costs for the year 2030 is based on the methodologies adopted in the EU SysFlex Project [264]. Interpolation is then used to estimate the system costs for the remaining years up to 2030. Note that while all the costs in Figure I-21 are simplified and draw on existing information in the public domain [257, 265-268] (see also Appendix A for more detail), they give an important sense of the investment required. An in-depth analysis is necessary to assess more accurately the total cost related to high penetration of renewables in the All-Island system.

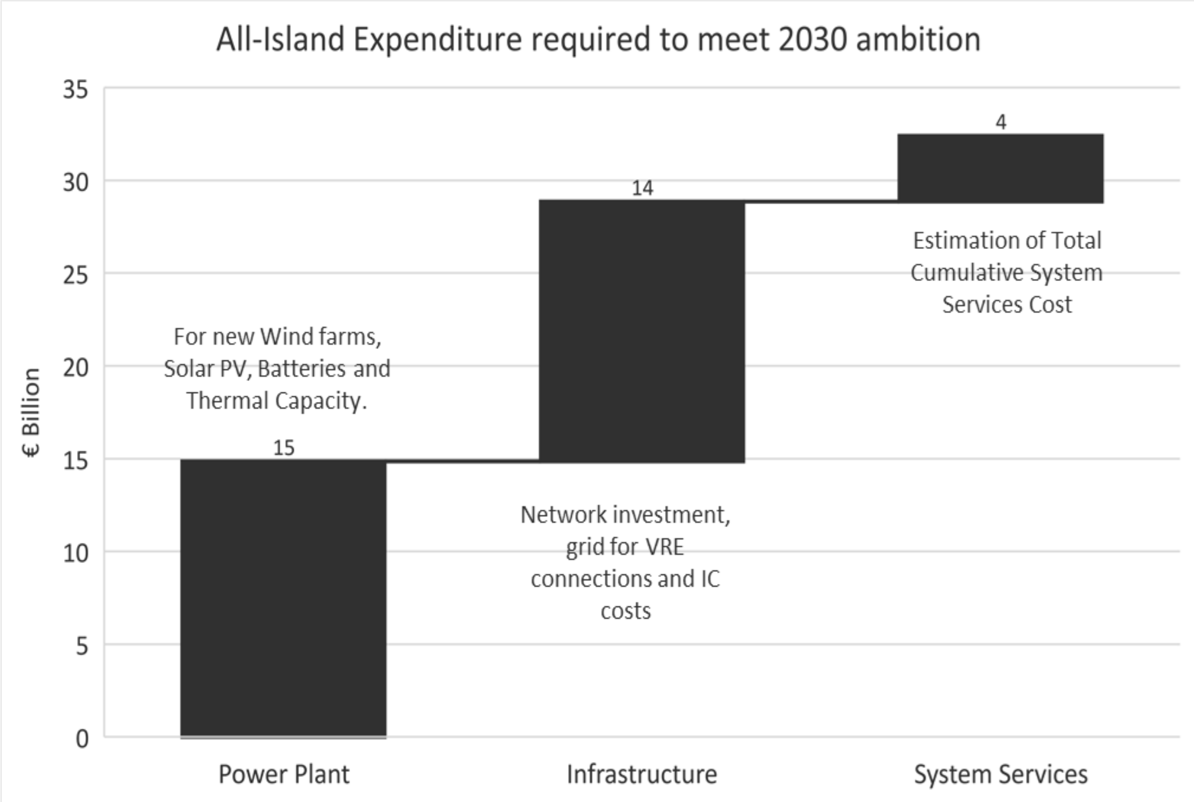


Figure I-21: Investment and capital expenditure required for the 2030 Base Scenario

The figure above excludes investment in the wider energy system such as the need for retrofitting homes, the installation of heat pumps and charging infrastructure for EVs which is also estimated at a further 30€ billion (this excludes EV vehicle costs and associated subsidies). These costs are important as they allow the wider energy system to leverage on the accelerated decarbonisation and improved efficiency of electricity as a decarbonisation vector. The cost of bringing a home to a cost optimal standard is determined by a number of factors including the size and type of home as well as the starting condition of the home. A cost-optimal analysis commissioned by the Department of Housing, Planning and Local Government in Ireland estimated the cost to achieve a B2 rating from a starting point of a D or E rating to be in the range of €21,000-€39,000. The costs considered in this study were focused on the system and investment costs. The cost to the consumer is another important aspect that needs to be studied and may form part of future work.

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Appendix A Additional Information for Annex 1

A.1 The All-Island System and the Rest of Europe

This graphs below present the outcomes of the All-Island System in terms of carbon intensity and resulting wholesale electricity prices in comparison to other EU countries modelled.

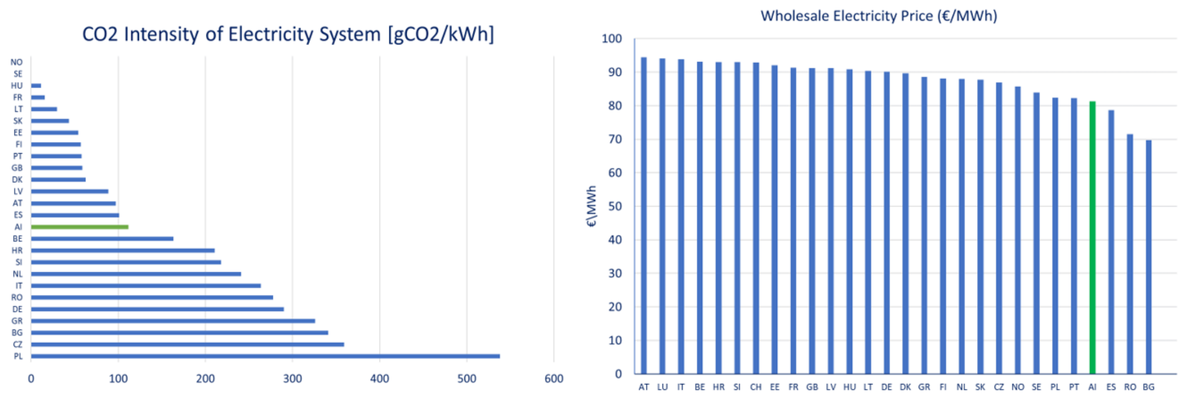


Figure A-1: How the 2030 All-Island System compares in Carbon intensity and wholesale electricity prices to other modelled EU countries.

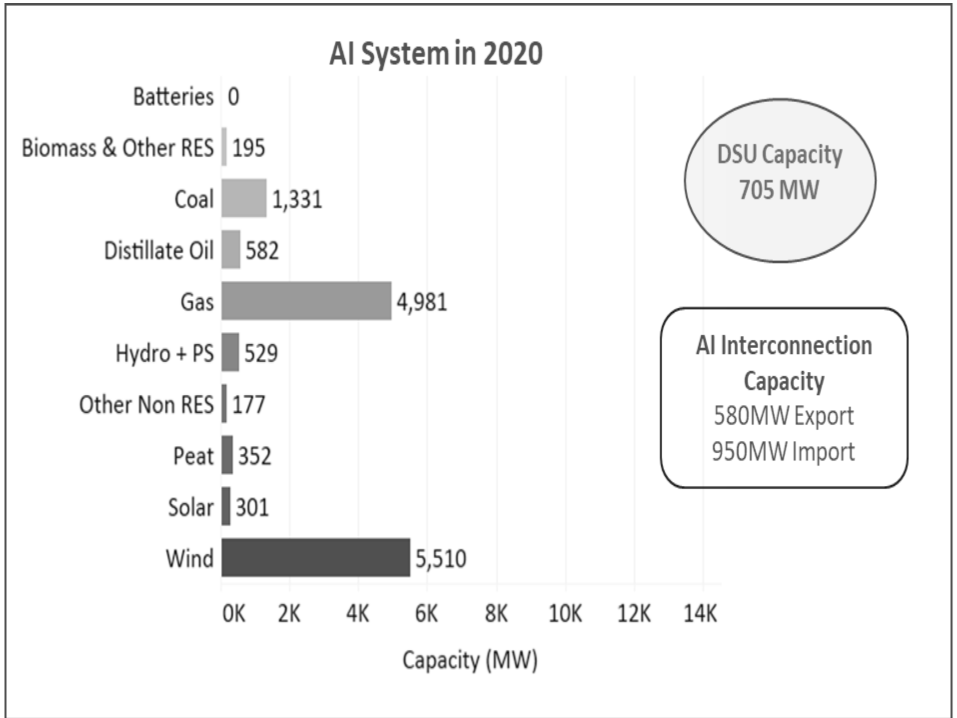
A.2 Scenario Inputs and Assumptions

	2030 Base	Lower Flexibility	Lower Electrification	Weather Years	S1 - Min Units Removed	S2 - Increased Wind	S3- Increased Smartness	S4 - CCS	S5 Varying GB + FR RES
Demand (TWh) (includes EVs and HPs)	53.7	53.7	52.3	53.7	53.7	53.7	53.7	53.7	53.7
No of EVs	1,000,000	1,000,000	800,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
No of HPs	750,000	750,000	600,000	750,000	750,000	750,000	750,000	750,000	750,000
EV & HP Smart Moveable Load	20%	20%	20%	20%	20%	20%	40%	20%	20%
AI Generation Capacity (MW)									
Biomass & Other RES	455	455	455	455	455	455	455	455	455
Gas	5204	5204	5204	5204	5204	5204	5204	4754	5204
Gas CCS	0	0	0	0	0	0	0	450	0
DO	272	272	272	272	272	272	272	272	272
Wind	11634	11634	11634	11634	11634	15584	11634	11634	11634
Solar	3317	3317	3317	3317	3317	3317	3317	3317	3317
Battery	1100	1100	1100	1100	1100	3500	1100	1100	1100
Other Non-RES	198	198	198	198	198	198	198	198	198
Hydro + PS	529	529	529	529	529	529	529	529	529
DSU	750	750	750	750	750	750	750	750	750

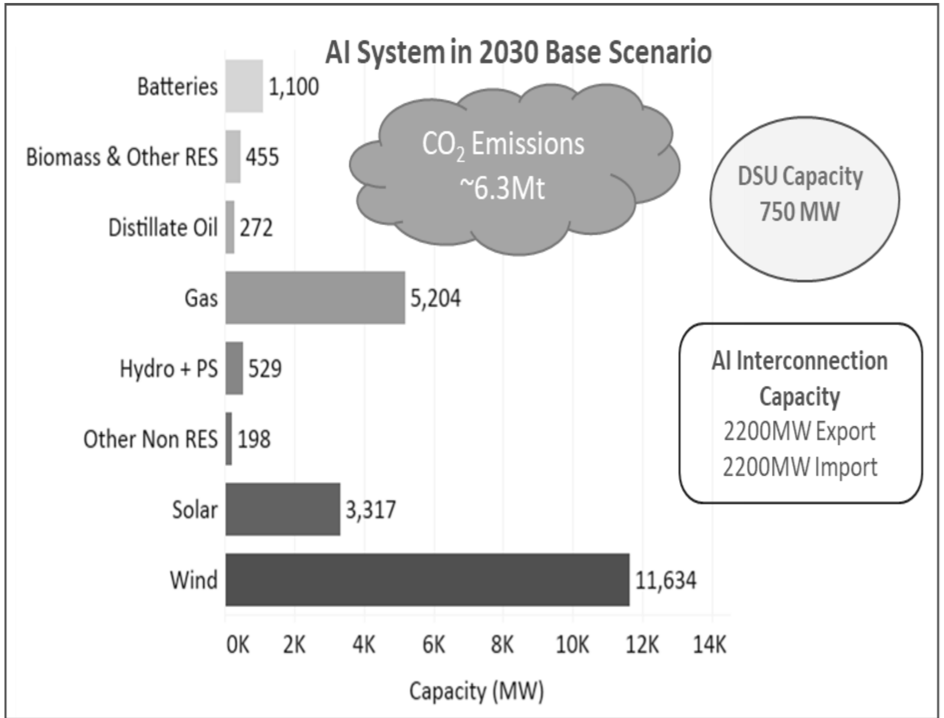
	2030 Base	Lower Flexibility	Lower Electrification	Weather Years	S1 - Min Units Removed	S2 - Increased Wind	S3- Increased Smartness	S4 - CCS	S5 Varying GB + FR RES
AI Interconnection Capacity (MW)	2200	2200	2200	2200	2200	5000	2200	2200	2200
Moyle Import/Export	500	500	500	500	500	500	500	500	500
EWIC Import/Export	500	500	500	500	500	500	500	500	500
Greenlink Import/Export	500	500	500	500	500	500	500	500	500
Celtic Import/Export	700	700	700	700	700	700	700	700	700
Additional Interconnection	0	0	0	0	0	2800	0	0	0
System									
SNSP Limit	95%	75%	95%	95%	95%	95%	95%	95%	95%
Min Inertia Level	None	17.5 GWs	None	None	None	None	None	None	None
Min synchronous generators required ('Min Units')	4	6	4	4	0	4	4	4	4
10% More GB/FR Wind	No	No	No	No	No	No	No	No	Yes
Carbon Tax €/tCO2	33.5	33.5	33.5	33.5	33.5	33.5	33.5	33.5	33.5
Fossil Fuel Price €/GJ Coal Gas Oil	 3.6 9.9 16.4	 3.6 9.9 16.4	 3.6 9.9 16.4	 3.6 9.9 16.4	 3.6 9.9 16.4	 3.6 9.9 16.4	 3.6 9.9 16.4	 3.6 9.9 16.4	 3.6 9.9 16.4

Table A-1: Scenario Inputs

A.3 Comparison of 2020 to 2030 Base Scenario



AI Demand ~40.2 TWh	~20,000 EVs ~45,000 ASHP	Smart Moveable Load N/A
Min Inertia Level 23,000MWs	Min No of Synchronous Generators ('Min Units') 8	SNSP Limit 65%
AI RES Target ~40%	Local constraints	VRE Curtailment ~7%



AI Demand 53.7 TWh	1,000,000 EVs 750,000 ASHP	Smart Moveable Load 20%
Min Inertia Level None	Min No of Synchronous Generators ('Min Units') 4	SNSP Limit 95%
AI RES Target 72%	No local constraints	VRE Curtailment ~7%

Figure A-2: Comparison of 2020 to 2030 Base Scenario

A.4 Overview of Expenditure and Investment Required

Category	Item	Cost	Units	Source	Total Costs (Million €)
Residential Requirements	Air Source Heat Pumps	11000	€/unit	SEAI	8,250
Residential Requirements	Residential Retrofits	30000	€/unit	Government of Ireland	22,500
Power Plant	Onshore Wind	1434	€/kW	IWEA 70*30 Study	7,463
Power Plant	Offshore Wind	2949	€/kW	IWEA 70*30 Study	4,129
Power Plant	PV	732	€/kW	IWEA 70*30 Study	2,428
Power Plant	Batteries	380	€/kW	IWEA 70*30 Study	836
Infrastructure	Offshore grid connections	496	€/kW	IEA Task 26	694
Infrastructure	ESB Networks ‘Strategy to 2027'	10	Billion €	ESB Networks ‘Strategy to 2027’	10,000
Infrastructure	Interconnection costs	1000	€/kW	UCC Own Estimation	1,200
Infrastructure	Network Costs	2.1	Billion €	IWEA 70*30 Study	2,100
System Services	DS3 Costs	3.5	Billion €	IWEA 70*30 Study/UCC Own Calculation based on EU SysFlex mmethodology	3,548

Table A-2: Overview of Expenditure and Investment Required

A.5 Overview of results from scenarios and sensitives

				Sensitivities			
	2030 Base	Lower Flexibility	Lower Electrification	Removal of Min Units	Increased wind capacity	Increased 'smartness'	CCS
All-Island RES-E (%)	72%	66%	73%	72%	97%	72%	72%
CO2 Emissions (Megatonnes)	6.3	7.2	6.2	5.5	5.1	6.3	5.2
Carbon Intensity (g/kWh)	118	135	115	103	95	117	94
Variable RES Curtailment	7%	16%	8%	6%	6%	7%	7%
Conventional Gas Generation (GWh)	15942	18117	15471	13759	12736	15677	19516
Wind and Solar Generation (GWh)	34971	32008	34742	35309	48513	35114	35000
Other Generation (GWh)	4403	4377	4397	4421	4396	4408	4407
Average Running hours per CCGT	5971	7279	5825	4339	5105	5861	5890
Average Hours at Minimum per CCGT	1390	2449	1349	447	1350	1309	1637
Net Exports from All-Island	1344	2780	2055	-260	11359	1248	1477

Table A-3: Overview of results from scenarios and sensitivities