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Analysing Evolutionary Pathways for the European Power System resulting from Climate Mitigation Policy

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Declaration

"This is to certify that the work I, Fiac Gaffney, 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."

Fiac Gaffney

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Executive Summary

The need for robust analysis of decarbonisation pathways has never been as high or as demanding. Globally, climate action is picking up pace. Yet, its momentum may hinge on informed policy decisions being made in a timely manner. Energy research must provide the analysis for these informed decisions. However, the scientific field lags others such as medicine or economics in moving to more open and reproducible science. The fact that this research is directly relevant to the urgent policy challenge of rapid energy system decarbonisation makes reproducibility of results particularly important. Aligning with this belief, all models and datasets used as part of this thesis are made openly available and accessible.

The central focus of this thesis is to understand the effects of climate mitigation policy on Europe’s power sector. The approach applied in this thesis looks back in time as well as forward to capture the learnings from previous marketplace evolutions that may help avoid similar pitfalls in the future. Coupled with insights from a power system already having to endure complete market transformation while attempting to remain fit-for-purpose, this knowledge is the basis for analysing proposed decarbonisation pathways for Europe in terms of policy, regulation, economics and system operation perspectives.

Today, policymakers and society are confronted by important decisions regarding the balance between cost equality, economic growth, energy security and climate action on a global scale. The key contributions of this thesis to that decision making process are new insights into the effects of policy decisions on cost inequalities stemmed from cross-border subsidisation of renewable energies, the risk exposures associated with over-reliance on technological development/readiness and finally a better, more well-rounded understanding of power system operational concerns in this brave, new decarbonised world.

Units and Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
AER	Alternative Energy Requirement
AI	All Island (of Ireland)
BIGCC	Biomass Integrated Gasification Combined Cycle
BECCS	Bioenergy with Carbon Capture and Storage
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CER	Commission for Energy Regulation
CO_2	Carbon Dioxide
CPM	Capacity Payment Mechanism
CRM	Capacity Remuneration Mechanism
DAC	Direct Air Capture
DE	Domestic Exports
EC	European Commission
EMHIRES	European Meteorological Derived High-Resolution Renewable Energy Source
ENTSO-E	European Network of Transmission System Operators
ERA	Electricity Regulation Act
ESB	Electricity Supply Board
ETP	Energy Technology Perspectives
ETS	Emissions Trading Scheme
EU	European Union
EUPHEMIA	EU Pan-European Hybrid Electricity Market Integration Algorithm
FFR	Fast Frequency Response

FPRAPR	Fast Post-Fault Active Power Recovery
GB	Great Britain
GFC	Gross Final Consumption
GHG	Greenhouse Gas
GJ	Gigajoule
GW	Gigawatt
GWh	Gigawatt Hour
hr	Hour
Hz	Hertz
IC	Interconnection
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
I-SEM	Integrated Single Electricity Market
JRC	Joint Research Centre of the European Commission
$kgCO_2$	Kilogram of CO_2
kW	Kilowatt
kWh	Kilowatt Hour
min	Minute
Mt	Megatonne
MW	Megawatt
MWh	Megawatt Hour
NET	Negative Emissions Technology
NI	Northern Ireland
OCGT	Open Cycle Gas Turbine
OECD	Organisation for Economic Co-operation and Development
OPEX	Operating Expenditure

PtG	Power-to-gas
PSO	Public Service Obligation
PV	Photovoltaic
RA	Regulatory Authority
REFiT	Renewable Energy Feed-in-Tariff
REF	Reference
RES	Renewable Energy Source
RES-E	Renewable Energy Sourced Electricity
RO	Reliability Option
RoCoF	Rate of Change of Frequency
s	Second
SC	Synchronous Condenser
SEM	Single Electricity Market
SIR	Synchronous Inertia Response
SMP	System Marginal Price
SNSP	System Non-Synchronous Penetration
SONI	System Operator of Northern Ireland
STES	Short-term Thermal Energy Storage
t	Tonne
TM	Target Model
TSO	Transmission System Operator
TW	Terawatt
TWh	Terawatt Hour
UK	United Kingdom
UNFCCC	The United Nations Framework Convention on Climate Change
UTES	Underground Thermal Energy Storage

VRE	Variable Renewable Energy
WE	Wheeled Exports
WWS	Wind, Water & Sunlight

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Chapter 1: Introduction

1.1 Background

Climate Action has become a powerful driver of energy sector policy, especially since the signing of the Paris climate agreement in December, 2015 (UNFCCC, 2015). Globally, the energy sector contributes two-thirds of all greenhouse gas (GHG) emissions (International Energy Agency, 2018), making it the single largest emissions source and, therefore, inextricably linked to the success or failure of achieving the agreed emissions reduction. Electricity accounts for just 19% of today's final energy consumption sector, yet it has experienced more success in decarbonisation than other areas combined. The word "success" is inherently subjective in nature and applied here in relative terms with respect to any form of sectoral decarbonisation, of which there is little. The challenge remains stark. In 2018 for example, global electricity demand rose by 4% and generation from coal- and gas-fired power plants increased considerably, driving up CO_2 emissions from the sector by 2.5% (International Energy Agency, 2019). Electricity has never been more essential to society than it is today. As such, ensuring a smooth transition away from the ever-reliable yet ever-polluting fossil fuel-based electricity generation to a more sustainable alternative is of upmost importance.

Motivated by overlapping challenges of climate change, security of supply and health impacts, multiple analyses involving varied levels of effort, technological development and policy support have explored the roles of high levels of renewable electricity, low carbon nuclear power, increased energy efficiency and carbon sequestration on electricity system decarbonisation (Capros et al., 2013; Capros et al., 2016; European Climate Fund, 2010; European Commission, 2011; International Energy Agency, 2017b; International Energy Agency. Office of Energy Technology, 2006; IPCC, 2014; Jacobson et al., 2018; Krey and Clarke, 2011). However, the prospect of 100% or near-100% renewable electricity (or energy) systems has ignited several debates within the energy modelling community on their technical feasibility and/or economic viability, often leading to contentious exchanges on different viewpoints. Public controversies such as that surrounding Jacobson et al. (2015) and Clack et al. (2017) divergent views regarding a fully decarbonised U.S. energy system highlight the importance of the assumptions going into the models used to determine the feasibility of such scenarios. Yet energy research lags behind other scientific fields such as medicine or economics (Begley and Ellis, 2012; Downing, 2004) in moving to more open and reproducible science (Pfenninger, 2017; Pfenninger et al., 2017). The fact that this research is directly relevant to the urgent policy challenge of rapid energy system decarbonisation makes reproducibility of results particularly important (DeCarolis et al., 2012; Nature, 2014).

Aside from the many divergent views on a 100% renewable pathway, achieving carbon-neutrality in the electricity sector may not even be adequate, according to recent reports by the Intergovernmental Panel on Climate Change (IPCC, 2018) and the European Commission (2018). The IPCC report highlights the importance of carbon dioxide removal and net negative emissions within the economy to achieving the goals of the Paris climate agreement – a view shared by Glynn et al. (2018); Grubler et al. (2018); Kriegler et al. (2018); Rogelj et al. (2018); Strefler et al. (2018); van Vuuren et al. (2018). Negative emissions technologies (NETs), such as bioenergy with carbon capture and storage technology (BECCS), offer the prospect of electricity supply with large-scale net negative emissions (Chen and Tavoni, 2013; Marcucci et al., 2017). However, notwithstanding the reality that there are no NETs currently in commercial operation in the electricity sector, there are also challenges and risks associated with the availability and provision of fuel (biomass for BECCS), transportation and storage of CO_2 and the financing of such plants (Davis et al., 2018; Kapetaki and Scowcroft, 2017). Energy system modelling can (and must) reduce these types of uncertainties by moving towards highly transparent, reproducible science.

The role of energy modelling to guide climate and energy policy alongside regulation for both guidance and direction is pivotal if the sector is to evolve into a more carbon-friendly entity. Coordinating support schemes for renewables may provide the necessary platform to eliminate the potential for cost inequalities caused by cross-border subsidisation of electricity across a multi-country region, leading to a more equitable and optimal electricity sector decarbonisation. In a similar vein, regulation must support strategies to facilitate renewable ambitions with market economics and system operations by establishing an optimal balance between efficiency, flexibility and adequacy while maintaining a fully functional electricity market that strives to adapt to evolving conditions without affecting the competitive edge that protects consumers.

‘Over the coming decades, continued sectoral evolution will rely on focused energy policy and strong regulation for both guidance and direction, but also on technological development to dictate the level of decarbonisation achieved, all the while remaining cognisant of, and managing, exposure to catastrophic risk.’

– a statement penned by the author of this thesis that encapsulates the motivation behind this thesis.

1.2 Aims

This thesis addresses the following research questions (RQ):

1. How did the electricity sector in Ireland evolved over the past century and what were the key learnings for the future?
2. How can power sector decarbonisation ambitions be reconciled with market economics and system operations?
3. Can coordinated European policy support schemes for renewable energies lead to more equitable and optimal power sector decarbonisation?
4. Should Europe aim for a negative emissions power system over a high renewable alternative?
5. Can a 100% renewable energy system be operationally resilient in Europe when based on wind, water and sunlight alone?

The following section summarises the thesis and describes where each aim is addressed.

1.3 Thesis in Brief

- **Chapter 2: (*RQ 1*)** A 100-year review of electricity sector policy in Ireland. Documenting a story that is recognisable almost anywhere in the world; from a nation struggles to establish an electricity sector, through security of supply concerns and leading to portfolio diversification. The chapter discusses the key events that occurred globally which gave clear impetus to energy policy in Ireland making it a world-leader in the facilitation of variable renewable energy, i.e. wind power.
- **Chapter 3: (*RQ 2*)** This chapter uses Ireland's evolving electricity market as a case study to identify strategies required to reconcile renewable ambitions with market economics and system operations on a small, isolated electricity system akin to many island nations worldwide. The case study focuses on the establishment of an optimal balance between efficiency, flexibility and adequacy while maintaining a fully functional electricity market that strives to adapt to evolving conditions without affecting the competitive edge that protects consumers.

- **Chapter 4: (*RQ 3*)** An analysis showing the potential for cross-border subsidisation of renewables resulting from uncoordinated policy support schemes. Methodological-rich chapter which outlines and demonstrates a more equitable and optimal approach to power sector decarbonisation using an innovative post-processing approach to identify the origins of the renewable electricity being transferred between countries based on an hourly simulation of the European power system in 2030. This chapter aims to provide policy makers with ‘food for thought’.
- **Chapter 5: (*RQ 4*)** A comparative analysis of decarbonisation trajectories for the European power system in 2050. This discrete scenario analysis compares a negative emissions power system to a high renewables alternative in terms of emissions reduction, technical operation and total system costs. Investigating whether a high renewable power system coupled with low levels of negative emissions technologies such as biomass carbon capture and storage could deliver negative emissions for the European power system without breaching published sustainable domestic biomass potentials in Europe or geological storage potential.
- **Chapter 6: (*RQ 5*)** An evaluation of a 100% renewable energy system primarily based on wind, water and sunlight. This chapter examines the technical feasibility of a 100% renewable Europe, basing the results on a replication and extension of the Jacobson et al. (2018) study using a detailed and available European power system model. Applying input data from the aforementioned study, the analysis aims to reproduce the highly electrified, highly renewable European energy system, testing the societally critical objective of providing a reliable power system whilst determining the relationship between variable generation, energy storage, transmission capacity and dispatchable power. Particular attention is paid to concerns outlined in recent literature on 100% renewable energy systems namely system adequacy, flexibility and stability.

The structure of this thesis is summarised in Figure 1.1 along with the over-arching themes that act as linkages between each.

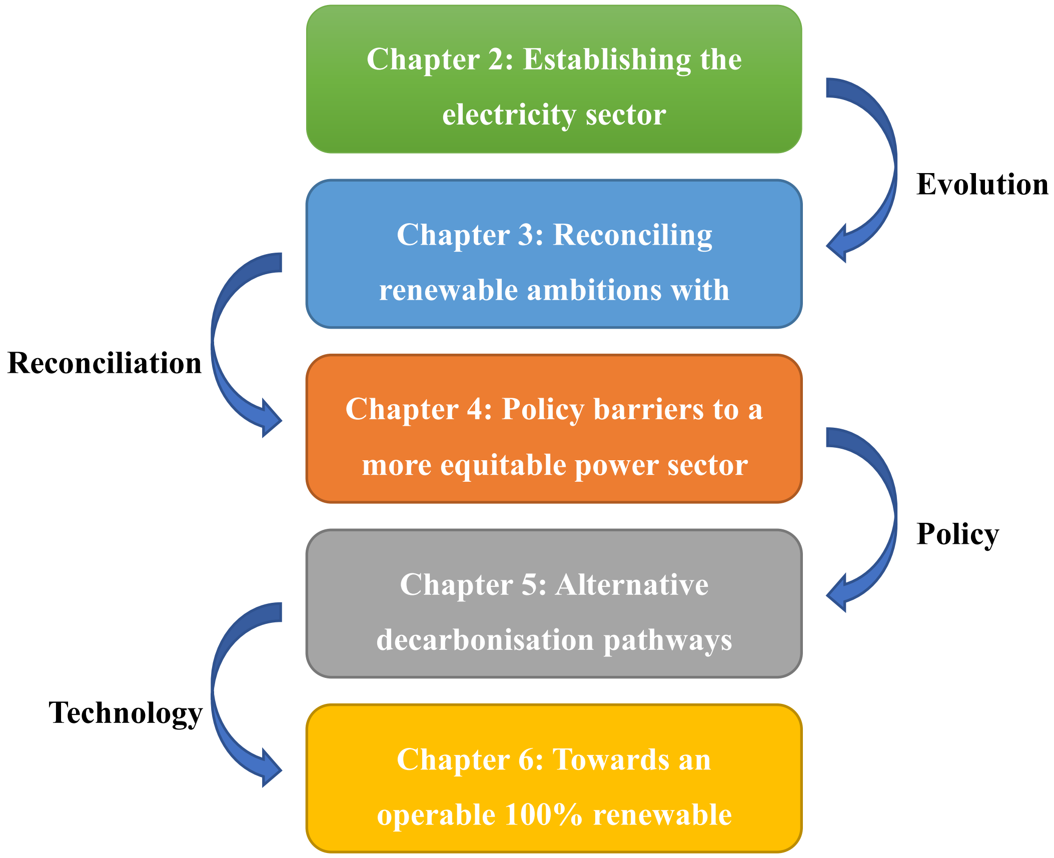

Figure 1.1: Thesis overview

1.4 Methodology

This thesis applies two research methods. Chapters 2-3, which are qualitative in nature, highlight the 'key learnings' from sectoral development over the past century before moving forward to discuss the regulatory advancements being implemented to facilitate renewable ambitions. Chapters 4-6 assume a quantitative approach where replication, simulation and examination of the European power system under different circumstances is carried out to improve understanding of incremental changes on decarbonisation, technical operation and market economics. In terms of geographical scope, Chapters 2-3 present case studies based on a small isolated electricity system which provides interesting insights to a system aiming to future-proof itself by adapting to their renewable ambition – could also be seen as a precursor to conversations yet to happen in larger, more interconnected systems. Chapters 4-6 encompass a larger regional power system containing between 30-40 countries depending on geographical scope of the specific scenario.

1.4.1 Soft-linked power system dispatch modelling

The modelling approach applied in Chapters 3-4 involve soft-linking power system models to larger energy system models, as first described by Deane et al. (2012). The interaction makes high temporal resolution, detailed unit commitment and dispatch modelling possible without simulating an entire energy system which is often computationally and economically exhaustive. The generation portfolios, demand and other attributes are taken from the energy system model and inputted into the power system model. There is no automatic feedback loop, hence the term “soft-linked” rather than the alternative. This approach can provide a multitude of insights around wholesale price forecasting, interconnection congestion, capacity expansion modelling, cycling of thermal capacity, curtailment, which may not be possible using an energy system model only.

1.4.2 Modelling platform

PLEXOS® Integrated Energy System Modelling software is used for power system modelling in this thesis (Energy Exemplar). PLEXOS® is a unit commitment and economic dispatch modelling tool that cost optimises the technical operation of a power system subject to technical constraints. For equations underlying the software, see Appendix A. The temporal resolution of simulations in this thesis varies between chapters from 60-minute to 5-minute.

Sub-hourly temporal resolution offers the added benefit of examining the technical ability of generation portfolios to achieve different levels of power output in short temporal timeframes as shown by Deane et al. (2014). For example, there is a higher likelihood ramp rates and other technical aspects of thermal generation will bind at 5-minute resolution compared to hourly dispatch. Deane et al. (2014) show that increasing temporal resolution increases the accuracy of estimating start cost of thermal power generation capacity.

1.4.3 Scenario analysis

In Chapters 4-6, a multitude of scenarios are presented and used for comparative analysis to inform policy and improve general awareness around different technologies. Scenario analysis allows the user to stress-test the robustness of assumptions. Introducing multi-sample weather variances into the models adds a level of confidence to the results through a resulting range or error bars that represent 30 years’ worth of data. This stochasticity can equally be applied to other inputs such as fuel prices, carbon prices, load data, to name a few.

In this thesis, scenarios are based on proposed European system conditions of 2030 and 2050 from a range of different sources. Each with their own individualities around installed generation mixes, demand forecasts and profiles, variable renewable energy profiles and operational constraints. These simulations are carried out with a view to inform policy development for the future of European power and energy systems. Throughout Chapters 4-6, a range of different analyses are identifiable. From analysing cross-border renewable electricity flows in Chapter 4, through carbon intensity quantification and total system cost estimation in Chapter 5, to determining potential operational attributes of different power generation types in a 100% renewable system gives a broad sense of where this thesis is and the landscape that it covers.

1.5 Role of Collaborators

This thesis is the summation of my research work in this area. However, it would not have been possible without a range of collaborative research which played a significant part in the formulation of all chapters. The essence of progressive research lies in collaboration that leverages expertise from multiple disciples and institutions to produce invaluable insights. To this end, this thesis was created off the back of various collaborate work with various institutes and universities. This section aims to provide clarity to the roles of these collaborations. It should also be noted that these five chapters are the result of five journal papers, of which two are published with three in the peer-review process.

- **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 Dr. Paul Deane provided guidance and reviewed drafts.
- **Chapter 3** is based on a paper submitted to a peer-reviewed international journal of which I am the lead author. I wrote this chapter in its entirety while Professor Brian Ó Gallachóir and Dr. Paul Deane provided guidance and reviewed drafts.
- **Chapter 4** is based on a published peer-reviewed journal paper for which I was the lead author. I developed the power system model and post-processing excel-based macro-enabled model which were subsequently validated by Dr. Paul Deane and Dr. Seán Collins. I wrote this chapter in its entirety while Professor Brian Ó Gallachóir, Dr. Paul Deane and Dr. Seán Collins provided guidance and reviewed drafts.
- **Chapter 5** is based on a paper submitted to a peer-reviewed international journal of which I am the lead author. I developed the power system model which was

subsequently validated by Dr. Glenn Drayton. Dr. Drayton also provided cloud computing services to expediate the simulation process which involved a high number of scenarios, each of which taking up to 20 hours simulation time. I wrote this chapter in its entirety while Professor Brian Ó Gallachóir, Dr. Paul Deane and Dr. James Glynn provided guidance and reviewed drafts.

- **Chapter 6** is based on a paper submitted to a peer-reviewed international journal of which I am the lead author. I developed the power system model which was subsequently validated by Dr. Paul Deane. Dr. Stefan Pfenninger and Dr. Iain Staffell provided generation profiles for wind and solar generation capacities. Dr. Padráig Daly provided invaluable knowledge around the technical issues regarding the testing of an operable 100% renewable power system. I wrote this chapter in its entirety while Professor Brian Ó Gallachóir, Dr. Paul Deane, Dr. Padráig Daly, Dr. Stefan Pfenninger and Dr. Iain Staffell provided guidance and reviewed drafts.

1.6 Thesis Outputs

1.6.1 Journal Papers

Gaffney, F., Deane, J., Daly, P., Pfenninger. S., Staffell. I., Ó Gallachóir, B. 2019. 'Reliably providing highly renewable 100% emissions-free electricity across Europe benefits from incorporating dispatchable generation.' Joule (In Review).

Gaffney, F., Deane, J., Drayton, G., Glynn, J., Ó Gallachóir, B. 2019. 'Comparing negative emissions and high renewable scenarios for the European power system.' BMC Energy (In Review).

Gaffney, F., Deane, J., Collins, S., Ó Gallachóir, B. 2018. 'Consumption-based approach to RES-E quantification: Insights from a Pan-European case study.' Energy Policy 112, 291-300.

Gaffney, F., Deane, P., Ó Gallachóir, B. 2019. 'Reconciling high renewable electricity ambitions with market economics and system operation: Lessons from Ireland's power system.' Energy Strategy Reviews 26, Article 100381.

Gaffney, F., Deane, J., Ó Gallachóir, B. 2017. 'A 100-year review of electricity policy in Ireland (1916–2015).' Energy Policy 105, 67-79.

1.6.2 Seminar, Webinar & Workshop Presentations

Gaffney, F., Deane, J., Ó Gallachóir, B. 'Reliably providing highly renewable 100% emissions-free electricity across Europe benefits from incorporating dispatchable generation.' Proc 38th International Energy Workshop 2019. 3rd-5th June 2019, International Energy Agency, Paris, France.

Gaffney, F., Deane, J. 'Taking a closer look at tomorrow's power systems with high resolution modelling.' Energy Exemplar Webinar. 1st May 2019, Environmental Research Institute, Lee Road, Cork, Ireland.

Gaffney, F., Collins, S., Deane, J. 'Experiences from Modelling European Power Systems using PLEXOS® Integrated Energy System Modelling Software.' Presentation to the Power System Operators of Latin America. 6th June 2018, Bogota, Columbia.

Gaffney, F., Deane, J., Drayton, G., Glynn, J., Ó Gallachóir, B. 'Comparing negative emissions and high renewable scenarios for the European power system.' TYNDP 2020 Scenario Development Workshop, ENTSO-E. 29th May 2018, Brussels, Belgium.

Gaffney, F. Cologne International Energy Summer (CIES) in Energy and environmental Economics 2017 Workshop, Institute of Energy Economics at the University of Cologne. 17th-21th July 2017, Cologne, Germany.

Gaffney, F., Deane, J., Collins, S., Ó Gallachóir, B. 'Consumption-based approach to RES-E quantification: Insights from a Pan-European case study.' Proc 36th International Energy Workshop 2017. 12th-14th July 2017, University of Maryland, College Park, Maryland, USA.

Gaffney, F., Deane, J., Ó Gallachóir, B. 2017. 'A 100-year review of electricity policy in Ireland (1916–2015).' ESRI – UCC Energy Research Workshop. 7th June 2016, Dublin, Ireland.

Chapter 2: A 100 Year Review of Electricity Policy in Ireland (1916-2015)

2.1 *Abstract*

Over the past century, Ireland's electricity sector has undergone a significant transformation. This chapter documents the nation's struggle to build an electricity system, to improve security of electricity supply through portfolio diversification and to promote indigenous energy sources. This was a challenge for an electrically isolated island with little natural resources. Here, we identify the ineffective policy decisions that left Ireland exposed to the 1970s energy crises. The crises did, however, provide a clear impetus for focusing Irish energy policy going forward. The successful deployment and integration of large-scale wind power was due to strong national and supranational policy decisions. In 2015, Ireland had the third highest wind energy share of national electricity demand (22.8%) of all IEA Wind Member Countries. The chapter also traces Ireland's transition through market reform, regional fragmentation and looks onwards to the EU internal market for electricity. This chapter provides a holistic view of the implications of various policy decisions on the electricity sector along with the stresses of external factors on the electricity market and should be useful for policy makers elsewhere faced with similar decisions.[1]

Keywords: Electricity sector policy; Evolving electricity market; EU Target Model; Historical review

[1] Published as: Gaffney, F., Deane, J. & Gallachóir, B. Ó. A 100-year review of electricity policy in Ireland (1916–2015). Energy Policy 105, 67-79 (2017).

2.2 Introduction

Over the past 100 years, Ireland's electricity sector has experienced significant change. Through the foundation of the State, World Wars and Energy Crises, the sector has continually expanded, bringing affordable electricity to the most rural parts of the country. The establishment of a national organisation to bring together small undertakings under one roof to build, maintain and continually develop the sector is common across developed countries. The struggles of many to improve security of supply during and after the 1970s oil crises is also well documented. Ireland's evolution over the last century differs however to that experienced in many other countries due to its geographically isolated position on the periphery of Europe, its lack of fossil fuel resources and its own geopolitical unrest. Historical reviews of this type can deliver key learnings surrounding the establishment and continuous development of a sector. In other words; distilling the knowledge gained over an extended period to help decision makers in countries under development. Reviews carried out by FitzGerald et al. (2005) and FitzGerald and Malaguzzi Valeri (2011) have previously focused on Irish energy policy in the broader context, opting for an entire energy sector view. Both papers view modern-policy decisions (generally starting around the 1970s oil crises) and provide an insightful assessment of the entire energy sector, mainly focusing on aspects such as: Security of Supply; Energy Needs of a Growing Economy; Competitiveness; Drivers of Change and Renewable and Environmental Policy. While O'Riordan (2000) published a review outlining the development of Ireland's power system between 1927 and 1997, it did not elaborate on the policy measures in place during the time. International review papers based on the electricity sector also tend to be theme related, with numerous papers concentrating on market liberalisation (Apt, 2005; Bye and Hope, 2005; Cameron and Cramton, 1999; Erdogdu, 2011; ESB National Grid, 2004; Fabrizio et al., 2007; Florio, 2014; Gratwick and Eberhard, 2008; Harris, 2011; Hattori and Tsutsui, 2004; Heddenhausen, 2007; Hyland, 2016; Jamasb and Pollitt, 2005; Joskow, 2008b; Karan and Kazdağli, 2011; Markiewicz et al., 2004; Nagayama, 2007, 2009; Nepal and Jamasb, 2012a, b; Newbery, 2002, 2005; Newbery and Pollitt, 1996; OECD, 2001; Parker, 2002; Sen, 2014; Sen et al., 2016; Sencar et al., 2014; Sioshansi, 2006; Sioshansi, 2008; Thomas, 2004; Williams and Ghanadan, 2006; Woo et al., 2003), climate mitigation (Australian Energy Market Operator, 2011; Buchan, 2013; Burke, 1989; Clancy et al., 2015; Cleary et al., 2016; Deane et al., 2014; Deane et al., 2015b; Deane et al., 2010; Doherty and O'Malley, 2011; ESB International and ETSU, 1997; Global Wind Energy Council & International Renewable Energy Agency, 2013; Henriot et al., 2013; Huber et al., 2007; Lipp, 2007; McGarrigle et al., 2013; O'Gallachoir et al., 2009; Saidur et al., 2010; Sensfuß et al., 2008; Staudt, 2000; Strachan et al., 2009; Tuohy et al., 2009; Yan, 2015) and market dynamics (Agency for the Cooperation of Energy Regulators, 2011, 2013; Barroso JM, 2006; Barroso et al., 2005; Booz & Co. et al., 2011; Botterud and Doorman, 2008; Bower and Bunn, 2001; Cini and Borragán, 2016; CREG, 2012; Deane et al., 2015c; EURELECTRIC, 2016; European Commission, 1996, 2003, 2009b, 2014a, 2016a; Glachant and Ruester, 2014; Gore et al., 2016; Gorecki, 2013; International Energy Agency, 2016a; Keay, 2013, 2016; Meeus et al., 2005; Midttun, 1997; Raineri et al., 2006; Robinson, 2016; Vazquez et al., 2002; Walsh et al., 2016), while others can be infrastructure and technology specific (Booz & Co. et al., 2011; O'Gallachoir et al., 2009; Passer, 1950; Saidur et al., 2010; Solangi et al., 2011; Tuohy et al., 2009). This chapter, on the other hand, begins before the foundation of the state and examines the different stages of development in the electricity sector over 100 years, with a clear focus on the role of policy. From the early infrastructure-related decisions surrounding generation capacity and network development, to the lack of policy decisions pre-energy crises that left the nation exposed and resulted in a renewed focus on energy policy domestically that led to improved security of electricity supply through diversification of the generation portfolio with coal, peat, natural gas and later, wind power being promoted. Here, we examine the role of electricity market liberalisation and regulation in the founding of the all-island single electricity market, in what was a significant step closer to the long-term plan; establishing the European internal market for electricity. The role of climate mitigation policies is likewise explored, which prompted the rapid growth of wind power in Ireland. And finally, some residual effects from the numerous energy policies on market dynamics are highlighted, raising concerns over modern-day market structures and their ability to host the anticipated future generation portfolio.

The chapter is structured as follows. Section 2.3 summarises the establishment and development of the electricity sector along with the diversification of the generation portfolio over the past century. Section 2.4 focuses on market liberalisation and regulation, outlining the phases that the Irish electricity market went through, from monopolistic control to complying with the EU Target Model. Section 2.5 describes the role of climate mitigation policies played in electricity generation, while Section 2.6 concludes the chapter by highlighting several policy implications.

2.3 Development of the electricity sector

The electricity industry had been in operation for more than 40 years before Ireland's first nationwide electricity market was established in 1927. The industry started small and was primarily based around the capital, Dublin, where local authorities and private companies generated and supplied electricity. Ireland was a political constituent of the United Kingdom (UK) until 1922, and as a result, the electricity sector developments in Ireland reflected that of the UK, albeit at a slower pace. The development and progress of the sector was both slow and uncoordinated due to the high number of small undertakings without any common long-term policy-driven plans (Shiel, 1984).

In the early 1900s, locally generated electricity from either small-scale hydro or coal spread across Ireland to the main municipalities. During the First World War, when coal rations were implemented, a paradigm shift in electricity generation occurred when the British Board of Trade investigated all indigenous sources of energy in the UK (Russell et al., 1929). During this period plans to generate energy from large-scale hydroelectric plants located on Ireland's waterways were presented. One such proposal played a defining role in the development of Ireland's electricity sector; harnessing the River Shannon.[2]

2.3.1 The Shannon hydroelectric scheme, 1925

Harnessing the energy of Ireland's longest river, the Shannon, was one of the first major developments of the newly formed Irish Free State.[3] Spear-headed by the Irish engineer Dr. Thomas McLaughlin while employed by German company Siemens-Schuckert, the Shannon hydroelectric scheme utilised a 30-metre head height on the river to deliver an electrical output of 85 MW. McLaughlin's plans also included a supply network to distribute the electricity nationwide. Once commissioned the Shannon hydroelectric plant, referred to as Ardnacrusha

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[2] Sir Robert Kane had previously proposed to harness the hydropower from the Shannon in 1844. The potato famine halted any further developments on the project (Kerr, 1943)

[3] The Republic of Ireland (referred to hereafter as Ireland) was initially known as the Irish Free State from its formation in December 1922 until 1937 when the constitution was changed (Foster, 1989)

due to its geographical proximity, was adequately sized to meet the entire national electricity demand in its early years of operation and to make Ireland's electricity sector 100% renewable.

After visiting the United States where, at the time, the electricity sector was more advanced, Ireland's newly formed first government decided that a public body should be formed to generate, manage and distribute the electricity generated under the Shannon scheme nationwide. Once passed into statutory law the Shannon Electricity Act, 1925 changed the outlook of the sector immediately as electricity was soon to be transmitted around the country (Shiel, 1984).

2.3.2 Establishing the Electricity Supply Board, 1927

The state-owned Electricity Supply Board (ESB) was established under the Electricity (Supply) Regulation Act, 1927 and placed in charge of operating, managing and maintaining the Shannon scheme, and distributing the electricity countrywide. In a move, which would have a profound effect on the future of the sector, the ESB turned down the option of selling electricity in bulk to other distributors, as allowed under the aforementioned Act and instead opted to deliver electricity directly to consumers on a non-profit-making basis. While the decision was strongly opposed by local authorities, it was made on the basis that local politics and municipal boundaries should not hamper the development of a national electricity network (Shiel, 1984). The decision removed the issues that caused slow developments in the past and instead presented a unified approach; aiming to create a nationwide electricity network.

The newly formed ESB, with the backing of the government, decided to acquire all existing electricity undertakings operated by local authorities, private companies, and small entrepreneurs.[4] As many of these undertakings employed different standards and voltages, this decision effectively harmonised the electricity supply nationwide. The result was a state-owned vertically integrated company that enviably gained the complete market share.[5] Once

[4] Prior to the Electricity (Supply) Regulation Act in 1927, there were 160 undertakings generating and supplying electricity in Ireland (Manning and McDowell, 1984)

[5] It must be noted that evidence shows ESB providing electricity at a fraction of the price other companies charged at the time. See the ESB online archive for details (ESB, 2016)

the last of the undertakings was acquired Ireland's electricity market became internalised within the confines of the ESB – something that would not change until 2000.

2.3.3 Sector development and rural electrification, 1930-1960

By the time Ardnacrusha was commissioned in 1929, the ESB had a transmission and distribution network (110/38kV) ready to transfer electricity nationwide, see Figure 2.1. This was a major development for Ireland and the first step in rural electrification. In 1930, Ardnacrusha and the coal-fired plant at Pigeon House, Dublin were synchronised for the first time, in what was a significant step to ensuring a stable electricity supply. Over the next decade generation capacity increased and electricity generation became more fuel diversified and geographically dispersed. New hydroelectric plants were commissioned, and peat was considered as an alternative fuel source for electricity generation, in parallel with the pursuance of rural electrification policies. However, priorities changed once the Second World War commenced. With coal rationed, peat was promoted as a viable alternative;[6] one that included the benefits of being indigenous, widely available and, from a socio-economic point of view, advantageous to rural Ireland (Tuohy et al., 2009). Plans for rural electrification suffered a setback during this period of unrest and it was not until the Rural Electrification Scheme (1946) and the Electricity Supply Amendment Act (1955) were passed that the electricity network started to reach the most rural and isolated communities in the country.

[6] The First Development Plan was passed in 1946, calling for two peat-fired ESB power stations to be commissioned and 24 bogs developed. In 1950 the Second Development Plan forced ESB to commission four more plants on the western seaboard solely for socio-economic reasons (Clarke, 2006)

Figure 2.1: Ireland's transmission system in 1930. Source: Development of Ireland's Power System 1927-1997 (O'Riordan, 2000).

2.3.4 The 1970s oil crises

After the rural electrification policies were implemented post-Second World War, the national electricity demand steadily grew and the ESB increased the generation capacity of the portfolio with new hydro, peat and oil plants commissioned. By 1970, 46% of Ireland's installed generation capacity was indigenous (peat and hydro) with the remainder being oil-based (O'Riordan, 2000). With more oil-fired units in the planning phase and yet devoid of any indigenous oil resources, this level of dependency left Ireland in an exposed position for the 1970s oil crises.

Both oil crises that occurred in the 1970s resulted from geopolitical instability. In each case, the sharp reduction in oil availability manifested themselves in the price of oil. The first in 1973/74 was triggered by American involvement in the Yom Kippur War, also known as the Arab-Israeli War. This caused the Organisation of Arab Petroleum Exporting Countries to declare an oil embargo which, over the following months, increased the price of oil globally from $3 per barrel to $12 (Post et al., 1990). The embargo was lifted in March 1974; ending the period known as the First Oil Shock. The second was a by-product of the Iranian revolution in 1979 and the Iran-Iraq War the following year. Iranian oil production was severely reduced over this period, causing panic and economic recessions around the world. Taking cognisance of the fact that global oil supply only decreased by 4% during this period, the price doubled to $39.50 per barrel (Lee and Ni, 2002). After these events, it was widely considered that the era of cheap oil was over.

In the decade spanning both oil crises, Ireland’s reliance on oil for electricity generation continued to increase. Oil represented 50% and 64% of primary energy used for electricity generation in 1970 and 1980 respectively (O'Riordan, 2000). Even with approximately 45% generation capacity fuelled by indigenous sources, the price spikes from oil had a telling impact on electricity prices in Ireland over the period, as seen in Figure 2.2.

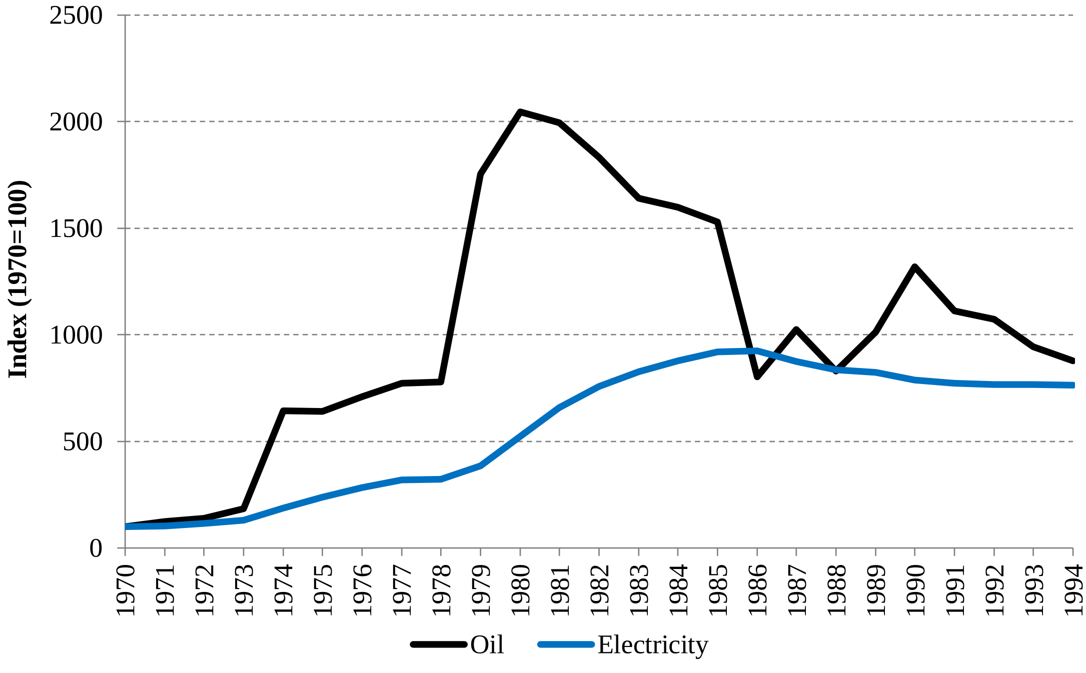

Figure 2.2: Evolution of global oil price and domestic electricity price in Ireland. Source: Oil prices retrieved from British Petroleum, Statistical Review of World Energy 2015 (British Petroleum, 2015); Domestic electricity price retrieved from ESB Archives, Dublin (ESB, 2016).

2.3.5 Diversifying the generation portfolio

In the 1950s the ESB had alerted the government to the exposure risk associated with over-dependence on a limited number of sources for electricity generation (Manning and McDowell, 1984). At first, the warnings related to hydro and peat but later, in the 1960s when the ESB had again raised concerns, the conversation had changed to oil. Unfortunately, the ESB were correct to voice concern in both instances according to Manning and McDowell (1984). In 1958/59 and again in 1963/64, Ireland experienced particularly wet weather conditions in one year and dry conditions in the following which affected peat harvesting and water levels in the hydro plants respectively, reducing the ability for peat-fired and hydro-based electricity generation. While in the late 1960s/70s, oil was affected by multiple events such as the Six Days War (1967), the cutting of the Trans-Arab pipeline (1970) and both previously mentioned oil crises.

It was not until a series of events in the 1970s that energy policy in Ireland became focused and began to shape the electricity sector for years to come. First, the oil crises proved to the government that over-dependence on a single fuel source, especially a non-indigenous fuel susceptible to geopolitical instability, heightened risk exposure, Second, natural gas of commercial quantity was found off the south coast in 1973 which would lower Ireland's import dependency and third, nuclear power became an option for providing base load power (FitzGerald et al., 2005).

During his description of Modern Portfolio Theory, Markowitz (1952) explains how effective diversification can reduce or even avoid risk exposure completely. Applying this theory to a generation portfolio, as FitzGerald et al. (2005) point out, means installing a number of fuel types with uncorrelated fuel prices to protect against any future price uncertainty – effectively acting as a hedging mechanism.[7] Over this period, the Irish government started to implement

[7] History shows a high correlation between oil and gas prices (FitzGerald et al., 2005)

Markowitz's theory by looking further afield at alternative energy sources to diversify the nation's generation portfolio.

2.3.5.1 Assessing the alternatives

Alternatives to oil-based electricity generation were examined to address concerns surrounding the nation's over-dependency on the commodity. It was found that hydropower was limited for further expansion,[8] peat offered little scope for development, coal was expensive compared to oil due to its labour-intensive nature, and other technologies such as solar, wind power, tidal, and wave energy were not far enough developed to be considered a viable alternative. It appeared that nuclear power was the only serious alternative to oil for providing base load power in Ireland (Manning and McDowell, 1984).

Over this period, gas-fired plants became more widely used in Ireland. Stemming from the newly developed indigenous gas resource along with advancements in gas combustion technology many oil-fired units were retrofitted to gas.[9] However, in the aftermath of the first oil crisis, actions were taken to ensure sufficient capacity margin was maintained for security of supply reasons. First, to meet short-term needs the ESB commissioned in excess of 500 MW oil-fired capacity that was already in planning; further increasing the nation's reliance on the commodity (O'Riordan, 2000). Second, and much to the dislike of ESB, new peat-fired stations were commissioned through the Third Development Plan for security of supply reasons.[10]

2.3.5.2 Nuclear power

In the late 1960s, the ESB began gathering specifications for a nuclear plant with the support of the government who, at the time, indicated their openness to nuclear energy (Manning and McDowell, 1984). While the Nuclear Energy Act was enacted in 1971, establishing a Nuclear

[8] The only hydro plant of any significant size commissioned to this day was a 292 MW pumped hydro energy storage plant in 1975. For more details, see: (O'Riordan, 2000)

[9] New combined cycle gas turbines achieved greater efficiencies than the widely used open cycle gas turbines operating at ~30%.

[10] In the early 1970s ESB stated that they did not regard peat-fired generation as a long term solution and instead thought it prudent to plan for its phase out (Manning and McDowell, 1984)

Energy Board and permitting the use of nuclear energy in Ireland, one of the main concerns was the minimum generating capacity of the plant. At 500 MW the capacity was seen as too large for the Irish system at the time (Manning and McDowell, 1984). In short, the government did not want to commit to a major capital-intensive project that could be oversized and therefore, under-utilised and seen as a waste of taxpayer's money. Increasing demand through interconnection with Northern Ireland (NI) was a key component of this plan. However, this would prove difficult as the two existing transmission lines were regularly targeted for attack due to political instability in the region and as a result out of commission (Manning and McDowell, 1984; O'Riordan, 2000).

By 1974, the ESB had drawn up plans and submitted technical and economic studies to establish a nuclear plant at five possible sites. The government appeared to agree with the ESB on the most suitable location of the project (Carnsore Point, Co. Wexford) and were looking to move forward with the project. Environmental concerns relating to nuclear energy were increasing across Europe, and in Ireland, as a growing opposition emerged targeting demonstrations at the various proposed sites around the country, prompting a negative public perspective towards the project. Acknowledging the growing discomfort around nuclear, the ESB drew up plans for alternatives. Coal was now the leading choice. The outlook for coal had changed since previous studies were carried out, mainly due to the opening of an international market which broadened the supplier base, increasing competition. In addition to alleviating the concerns regarding nuclear, coal plants could also be built more quickly and in smaller unit sizes (Manning and McDowell, 1984).

In 1978 a ‘Green Paper’ on energy policy was published.[11] This consultation document put the question of Ireland’s future direction on energy policy to the public. However, before discussions could take place the second oil crisis triggered a global recession. With electricity demand expected to decrease due to the economic downturn and with the nuclear disaster in Three Mile Island in 1979, all nuclear plans were put on hold indefinitely. This informed the decision to build a large coal-fired base load plant at Moneypoint; originally one of the proposed sites for a nuclear plant. Two 300 MW generating units were initially approved for

[11] Energy-Ireland: discussion document on some current energy problems and options (Department of Industry Commerce and Energy, 1978)

the site but this increased to three at a later date, with the potential for a fourth (O'Connor et al., 1981). The emphasis on energy supply security was evident in the provision of plans for expansion to a fourth unit, along with the fuel storage capacity of up to 2 million tonnes of coal (approx. one year's supply). Figure 2.3 shows the evolving generation portfolio in Ireland over almost a century.

2.3.5.3 Moneypoint coal plant, excess generation capacity and high electricity prices

Moneypoint, Ireland's first large scale coal-fired power plant, was commissioned between 1985-1987. The plant added substantial capacity to the generation portfolio with a maximum output of 915 MW (3 x 305 MW units) at an investment cost of IEP £700 million[12] (ESB, 2016). The capacity margin (the difference between installed capacity and peak demand) increased from the mid-1970s due to the commissioning of Moneypoint, as seen from Figure 2.3. For example, peak demand in 1977 was 71% of installed capacity compared to 56% in 1987. The excess generation capacity was considered a consequence of economic instability in the 1970s, a time when governments could not agree on macroeconomic forecasts, making long-term planning difficult. As a result, the ESB modelled future generation capacity needs using their own assumptions regarding; economic growth, fuel prices, and inflation (Manning and McDowell, 1984; O'Riordan, 2000).

The forecasting errors and the timing of the extra capacity commissioned at Moneypoint was unfortunate as the economy performed poorly as alluded to by FitzGerald et al. (2005). FitzGerald et al. (2005) also associate the high electricity prices experienced in the 1980s to this spare capacity which may not be completely accurate as the ESB, still to this day, cannot begin recovering capital costs from a project until after commissioning. Instead, from the evidence provided on the evolution of oil prices (Figure 2.2) coupled with the nation's over-dependence on the commodity over the same period (Figure 2.3) suggests fuel costs were a contributing factor in the continuous price rise and not solely costs associated to spare capacity.[13]

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[12] Irish pound was the currency in Ireland until 2002. Equivalent to €890 million.

[13] Interest earned during construction contributed to repaying the capital required for the construction of Moneypoint power station.

Over the next decade after Moneypoint was commissioned, electricity prices steadily decreased as a result of numerous factors working simultaneously, including excess generation capacity; no significant investment in new plant or infrastructure was required as assets were "sweated" according to Deane et al. (2015c), and portfolio diversification; more gas and coal generation and a global reduction in oil and gas prices.[14]

The electricity systems of NI and Ireland synchronised for the first time in two decades in the mid-1990s as the transmission lines re-energised. Expanding the system proved a major success for Ireland in terms of security of supply. Not alone could electricity be imported from NI but it could also be generated on mainland Great Britain (GB) and transmitted across the interconnector at Moyle.[15] It was not until 2012 that Ireland's electricity system became directly connected to GB when a 500 MW interconnector was commissioned.[16]

2.3.5.4 The development of wind power in Ireland

The sector continued to develop and further diversify throughout the 1990s and into the 21st century. The history of modern-day wind power in Ireland is an example of this development when it began with the first major demonstration project at Bellacorick, County Mayo. The project, funded through European Commission under the VALOREN programme (Council Regulation (EEC) No. 3301/86), contained 21 Nordtank turbines with a combined capacity of 6.45 MW (Burke, 1989). After performing "*very well with an average load factor of 30%*" according to Staudt (2000), the Irish government began supporting alternative energy sources in 1994 through a range of schemes and policy measures that aimed to encouraged investor

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[14] In the wake of the oil crises Ireland, along with many other countries, reduced their reliance on oil. This resulted in over-supply worldwide and the price of oil reducing for the first time since the second oil crisis. The overall decline in oil price continued over the following 20 years (even with the third oil crisis occurring in 1990) in what is referred to as the '1980s Oil Glut'. Gas prices also decreased during this period, dropping ~40 % between 1985 and 1995 (British Petroleum, 2015)

[15] The Moyle interconnector was commissioned in 2001. Owned and operated by Mutual Energy the interconnector connects NI with Scotland using two 250kV DC lines which can transfer a maximum capacity of 250 MW each. For more information, see: http://www.mutual-energy.com/

[16] The East-West interconnector was commissioned in 2012. This project was developed and is owned by the transmission system operator; EirGrid. For more information, see: http://www.eirgridgroup.com/

buy-in and lower the institutional barriers facing the technology. This aspect of Irish wind power is addressed in Section 2.5 which discusses climate mitigation policies.

Through focused energy policy over the last three decades, the Irish wind power industry has grown significantly. For instance; at the end of 2015, the installed wind power capacity in Ireland was 2455 MW according to the International Energy Agency (2015), producing the third highest contribution to national electricity demand (22.8%) of all IEA Wind Member Countries. However, fulfilling ambitious policy measures can often depend on physics and the ability of the electricity system to absorb this variable energy. Any power system operating with high levels of variable energy yet limited interconnection or storage capacity must adapt quickly in order to maintain system stability. Ireland's electricity sector has done so in reaching instantaneous penetration levels upward of 55% (one of the highest levels for a synchronous island system globally), and continues to adapt with a new market structure that promotes flexibility through a new energy market design, improved system services and redesigned capacity mechanism, all to be implemented in 2018.[17] Notwithstanding the fact this transformation in Ireland's electricity sector is needed to comply with the EU energy packages (see Section 2.4 for further details), it is also necessary for the marketplace to adapt to the changing generation portfolio which requires flexibility and reliability to complement variable energy sources, maintaining a stable power system. The story of Ireland's market evolution from monopolist control to participating in the European internal market for electricity is outlined in Section 2.4.

[17] 1st October 2018 is the date set out for Ireland to become compatible with the EU Target Model.

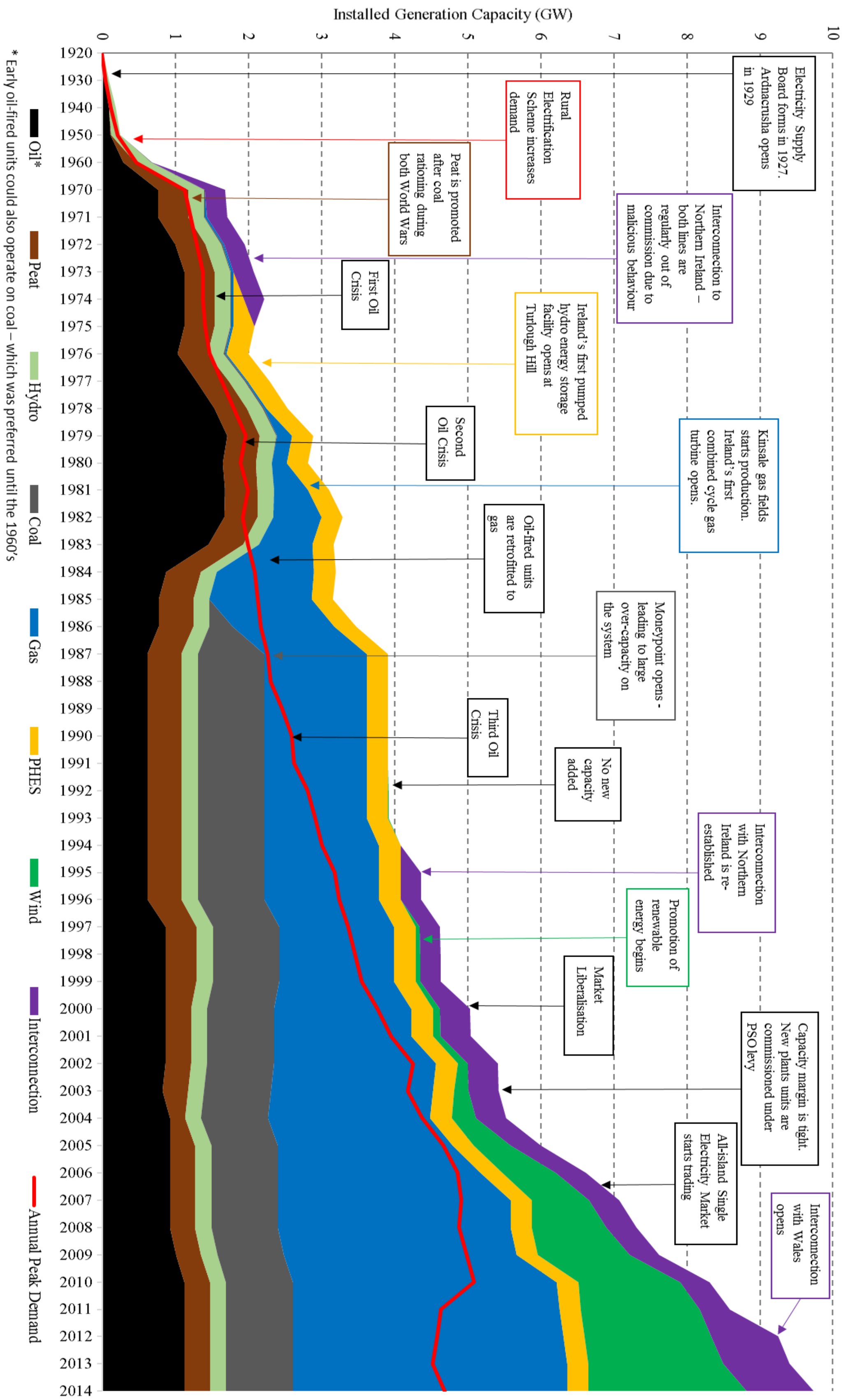

Figure 2.3: Total installed generation capacity and annual peak demand in Ireland Source: Sustainable Energy Authority of Ireland, Energy Balance, Dublin (Sustainable Energy Authority of Ireland); ESB Archives, Dublin (ESB, 2016).

2.4 Market liberalisation and regulation

Liberalising the energy markets of Europe has long since been a goal for the European Union (EU) and the European Economic Community that existed beforehand (Karan and Kazdaği, 2011). Since joining in 1973, Ireland has been a member of the various regional organisations that aim to increase economic integration between Member States (Hourihane, 2004). The long-term plan was to create a single internal market for free movement of goods, capital, services and people across the Member States (European Commission). As such, the establishment of competition laws to promote liberalisation within the internal market was a key aspect of EU policy–a paradigm shift away from the monopolistic market framework to a competitive alternative. For the electricity sector, this came in the form of EU Directive 96/92/EC,[18] known as the First Energy Package.

2.4.1 Market liberalisation

The First Energy Package implemented a new regulatory framework for the electricity sector across the Member States based on the three pillars of EU energy strategy: securing an expanding supply of energy; developing a more competitive internal energy market; and encouraging, supporting and developing renewable energy sources (Barroso JM, 2006). Through market liberalisation the Directive planned to restructure (unbundle) vertically integrated monopolies, increase market competition and allow consumers choose between suppliers, to make the energy sector more cost effective and, from a strategic point of view, to best manage Europe's risk exposure to imported fossil fuels and the associated geopolitical concerns that lie therein (Heddenhausen, 2007). The primary aim of the energy package (and liberalisation on the whole) was to improve social welfare across Europe (Möst, 2008; Yan, 2015). The First Energy Package initiated the most extensive energy market reform anywhere in the world according to Jamasb and Pollitt (2005).

Most developed countries started to liberalise their infrastructural sectors from the 1980s onwards. Early movers such as Chile (1982), UK (1989) and Argentina (1992) led the way in

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[18] European Union 1996 Directive 1996/92/EC of the European Parliament and of the Council of 19 December 1996, concerning common rules for the internal market in electricity.

energy market liberalisation (Bye and Hope, 2005; Karan and Kazdağli, 2011; Sen et al., 2016). While the motivation behind market reform differed between countries, they generally showed a desire to make the energy sector more cost effective by increasing efficiency within the wholesale and retail markets through the privatization of previously state-owned assets and introducing competition[19] (Harris, 2011). Other drivers of market reform also exist, such as a political ideology based on the faith of market forces and a dislike for resilient labour unions,[20] and the wish to attract foreign investment (Green and McDaniel, 1998; Joskow, 2008b; Newbery, 2002; Woo et al., 2003). Nevertheless, in a sector with high capital costs and long lead-times, questions remain as to whether a fully open and competitive market provides the necessary incentives for companies to invest in new plants when infra-marginal rents are continually being squeezed.[21] Ambiguity also remains as to whether reform leads to lower prices at all, as alluded to by (Apt, 2005; Erdogdu, 2011; Hattori and Tsutsui, 2004; Hyland, 2016; International Energy Agency, 2016a; Nagayama, 2007, 2009; Sioshansi, 2006; Thomas, 2004; Woo et al., 2003). Consequently, the suitability of the textbook model approach to market reform has been discussed extensively by (Gratwick and Eberhard, 2008; Nepal and Jamasb, 2012a, b; Sen, 2014; Sen et al., 2016; Tuluy and Salinger, 1993; Williams and Ghanadan, 2006).

2.4.1.1 Market reform in Ireland

Prior to reform, the ESB operated an electricity market in Ireland that was completely internalised within the organisation. With ESB Power Generation generating to meet the demand of its supply arm; ESB Customer Supply, in what could be described as a monopolistic state. When examined by the EU Competition Commission it was concluded that "*The current structure of the Irish electricity market is not favourable to competition*." (OECD, 2001, p.27). This draws attention to the fundamental concern of a monopoly where in theory, a legacy firm

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[19] Norway is a notable exception to this statement as they implemented market reform based on environmental policy rather than to make their energy sector more cost efficient. (Newbery, 1997)

[20] Prime Minister Margaret Thatcher's support for restructuring the state-owned Central Electricity Generating Board in England and Wales (Green and McDaniel, 1998)

[21] The UK's decision to introduce a capacity market for the first time in 2014 is a prime example.

can pass the true cost between its generation and supply departments allowing possible perverse behaviour.[22] Moreover, FitzGerald et al. (2005) highlight that Ireland has a history of promoting the interest of producers over consumers, an observation that endorses the Commission's findings.

On the other hand, a report compiled by IPA Energy Consulting (2001) for the Northern Ireland Department of Enterprise Trade and Investment and the Republic of Ireland Department of Public Enterprise concluded that Ireland's electricity prices (in real terms) were "*probably too low to support new, independent generation*." (IPA Energy Consulting, 2001, p.14). However, these low prices may be explained by the legacy monopolist improving its overall generation efficiency in anticipation of market reform through the Cost and Competitiveness Review programme that yielded net annual cost savings of IEP £90 million (€114 million) per annum[23] (ESB, 2000).

2.4.1.2 Electricity Regulation Act, 1999

The First Energy Package was transposed into national legislation as the Electricity Regulation Act, 1999 (ERA 1999). ERA 1999 transformed Ireland's electricity sector by outlining plans to: establish a national regulatory authority to oversee the transition to a liberalised market, Commission for Electricity Regulation (CER);[24] form an independent system operator responsible for operating the transmission network, EirGrid and; open the wholesale and retail markets to competition. These changes provided the backbone of market reform in Ireland; aiming to create an environment conducive to competition in the near future (OECD, 2001).

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[22] It should be noted that there was "*no significant market power exercised*" in Ireland as report by Cambridge Economics Policy Associates (2010), however it has occurred elsewhere. For details of the case brought against E.ON AG by the European Commission for the strategic withdrawal of capacity in German electricity market, see: http://ec.europa.eu/competition/elojade/isef/case_details.cfm?proc_code=1_39388

[23] This behaviour from incumbents was also seen in Brazil, US, and the UK (Bridgman et al., 2011; Gorecki, 2013; Markiewicz et al., 2004; Newbery and Pollitt, 1996).

[24] Later changed to the Commission for Energy Regulation when it was appointed the regulator for other services.

2.4.1.3 Market changes

Since February 2000 Ireland's electricity markets, both wholesale and retail, have been open to competition. The ESB's market share went from owning and operating 95%[25] of the installed generation capacity in Ireland to 51% in 2015.[26] This was assisted by independent power producers entering the market and a CER-ESB agreement to sell off generation assets (Commission for Energy Regulation, 2007; Commission for Energy Regulation & Electricity Supply Board, 2007). The retail market also experienced change as approximately 400 large users[27] of electricity could choose between suppliers in the first year. The ERA 1999 also provided third party access to the electricity network to 'green' (wind power and other sources of renewable energy) electricity suppliers to sell directly to *all* final customers, irrespective of the customer's consumption (O'Gallachoir et al., 2009), unlike 'brown' (fossil fuel based) electricity suppliers who could initially sell only to the aforementioned large users. This market opening for green suppliers was particularly important for the sections of the market that pay most for electricity (commercial and domestic customers). This provided wind farm developers with an alternative to the government support scheme route to the market.

In 2002 and 2004 the 'brown' electricity market was opened further, increasing to 40% and 56% respectively with full liberalisation occurred in 2005. The CER decided to regulate the ESB Customer Supply electricity price to reduce their market share to or below 60% in the Domestic and 50% in Business markets. Full deregulation of the retail electricity market was achieved in 2011 (Commission for Energy Regulation, 2010).

The structure of the wholesale market also changed with reform. While ESB Networks retained ownership of the transmission and distribution networks (operating the latter), complete control of the transmission network was afforded to the Transmission System Operator (TSO) with the

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[25] The remaining 5% was made up of small scale generation (OECD, 2001)

[26] Installed generation capacity information retrieved from the CER's validated PLEXOS® model, available at: http://www.cer.ie/

[27] Defined as a user consuming over 4 million kWh per annum. Large users represented 28% of the market.

enactment of the ERA 1999.[28] In terms of the market mechanism, the TSO continued to operate a bilateral contracts model as pre-liberalisation except with an interim electricity trading arrangement called a Top-Up and Spill mechanism included. Top-Up and Spill was a means of balancing long or short markets. Under this type of arrangement, the incumbent provides Top-Up and Spill services within their jurisdiction. The price of top-up services over the year was regulated by the CER based on the estimated cost of a Best New Entrant.[29] The spill costs reflected the incumbent's avoidable fuel cost.

Policy and regulatory responsibility in the market were shared by the Department of Enterprise, the Competition Authority, and the CER. The Department outlined policies to be implemented, which were often passed down from the EU, the Competition Authority analyses the market for instances of market power exertion or predatory behaviour,[30] and the CER governed the day-to-day running of the sector. The Trading and Settlement Code was an important document published by the CER during this period which outlined rules for market operation as well as for trading and settlement that underpinned the transparency and credibility which Ireland's electricity market is, still to this day, known for[31] (FitzGerald and Malaguzzi Valeri, 2011; Lyons et al., 2007).

2.4.2 Transitioning towards an EU internal electricity market

Once the Second Energy Package, EU Directive 2003/54/EC,[32] was adopted in June 2003 the pathway for a European internal electricity market became more crystallised (Karan and

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[28] The Act obliged the asset owner to maintain and expand the transmission network as the TSO requires, pending approval from the CER.

[29] Best New Entrant is calculated based on the infra-marginal rent necessary for a unit to recoup their capital costs.

[30] In 1998 the Competition Authority objected to an ESB lead 'Optisave Contract' initiative (for large customers) which required the customer that wanted to switch suppliers (due to lower prices) to provide details of the offer and allow an opportunity to match the offer. The contract stipulated that the customer would only be allowed leave if ESB CS could not match their competitors offer, and then only after six months' notice of termination (OECD, 2001)

[31] The CER also approved the TSO-lead implementation of Grid Code requirements for market participants relating to the material technical aspects of their plants.

[32] European Union 2003 Directive 2003/54/EC of the European Parliament and of the Council of 26 June 2003, concerning common rules for the internal market in electricity and repealing Directive 96/92/EC.

Kazdağli, 2011). Where its predecessor had shortcomings relating to market dominance and the possibility of perverse gaming behaviour, the Second Energy Package sought to implement a level playing field for all participants alike by ensuring non-discriminatory rights of access to the network and the publication of the basis for tariffs (European Commission, 2003). After liberalisation, the next step was regional fragmentation; a mid-step on the path to full implementation of an internal market which involved grouping markets based on their geographical proximity to one another. The concept was supported by the European Commission as it acknowledged the reduced complexity in coupling regional markets rather than on an individual, market by market basis (Karan and Kazdağli, 2011).

Electricity market coupling started in the Nordic region with Sweden and Norway creating the first multinational electricity exchange in 1990. This exchange expanded further when Finland and Eastern Denmark joined what is known as the Nord Pool four years later (Olsen, 1995). On mainland Europe, electricity market coupling first took place in 2000 with the formation of the European Energy Exchange, which later expanded outside of Germany when the French and Austrian markets joined to form the EPEX Spot market (European Energy Exchange, 2010). After Ireland's electricity market was reformed, a steering group was set up with representatives from Ireland and NI to assess the possibility of coupling the two markets. In 2004 the respective Regulatory Authorities[33] (RAs) from both jurisdictions signed a Memorandum of Agreement relating to a new market structure which, in 2005, was followed by legislation to underpin the All-island Single Electricity Market.[34]

2.4.2.1 Regional fragmentation

The All-island Single Electricity Market (SEM) was established in November 2007 as the central trading platform for electricity on the island of Ireland. Costing approximately €110 million, this cross-jurisdictional centrally-dispatched gross pool market with dual-currency is

[33] Consisting of CER from Ireland and the Northern Ireland Authority for Utility Regulation from Northern Ireland.

[34] The Electricity Regulation (Amendment) (Single Electricity Market) Act 2007 in Ireland and the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007 in Northern Ireland (Competition Authority, 2010).

fully liquid, due to its mandatory nature for generators and suppliers (Single Electricity Market Committee, 2012).

All generators above the 'De Minimis' 10 MW capacity level bid into the day-ahead market using their short run marginal cost which accounts for fuel, carbon and variable operation and maintenance costs, for delivery the following day. Bids are stacked and dispatched based on a merit-order curve that commits the lowest cost generators first, followed by more expensive units until the demand is met. The market employed a 'pay-as-clear' or 'marginal pricing' model, therefore the last successfully cleared generator in a trading period sets the System Marginal Price (SMP) which all dispatched plants receive, and suppliers pay.[35] Dispatch schedules can change after the economic dispatch has been complete due to transmission constraints and ancillary service requirements.[36]

For generators in the SEM, it offers a platform to sell their product with little or no risk exposure. For example; if a generator is constrained on but cannot recoup their fixed costs, then an adder called an 'Uplift' is included in the SMP to cover their costs. Similarly, if a unit has not earned enough infra-marginal rent to cover their fixed costs then a 'Make Whole Payment' is made to the generator to ensure a net balance of zero over a week-long period. Make Whole Payments, constraint payments, and imbalance charges are recovered from suppliers through an Imperfection Charge that is passed on to the end-user. There is also insurance on fixed cost recovery over the longer term through a capacity payment mechanism which as with its predecessor–the capacity margin scheme[37]–was introduced to ensure adequate

[35] Suppliers also pay other system charges and levies for network and obligatory requirements as judged necessary by the CER.

[36] For details of network constraints and ancillary service requirements, along with information on constraint payments, see: http://www.eirgridgroup.com

[37] The capacity margin scheme was introduced in 2001 as the margin between installed generation capacity and peak demand had eroded, as shown in Figure 3. Over this period, Ireland experienced large economic growth and forecasts showed continuous increases in demand over the following years. To ensure adequate levels of generation capacity were installed a capacity mechanism was introduced in 2001 to encourage new investment in Ireland's electricity sector by increasing the certainty of recouping capital costs (Commission for Energy Regulation, 2005) Generators benefitted from the scheme if their unit was available when capacity margins were tight. In these instances, the generator received an additional revenue stream that was mutually exclusive to any infra-marginal rent earned (Leahy and Tol, 2011) The associated cost was recouped from customers through the Transmission Use of System charge; a new addition to the standard electricity bill under the ERA 1999 (Commission for Energy Regulation, 2005)

installed generation capacity. The annual capacity 'pot' is set by the RAs using the previously mentioned Best New Entrant methodology.[38]

In terms of market structure and overall governance, some changes occurred with the introduction of SEM. For example, the RAs introduced the Bidding Code of Practice to restrict bidding strategies and eliminate opportunities for predatory behaviour by market participants.[39] This, along with other existing market codes such as the Trading and Settlement Code and Grid Code were monitored through the Market Monitoring Unit to ensure compliance and that no market power was exerted. Implementing market rules and general market operations are carried out by the single electricity market operator which is a joint venture between both TSOs.[40] Otherwise, the structure remained the same as pre-SEM with ESB Networks[41] retaining ownership of the transmission and distribution networks, operating the latter with the TSO controlling the former.

2.4.3 The EU Target Model

The EU Target Model for electricity emerged from the Florence Forum process in 2009 as a blueprint with both top-down and bottom-up guidance on the future market design deemed necessary to facilitate the EU integrated internal market for electricity (Booz & Co. et al., 2011). Aligned with the three energy packages,[42] the model outlines the necessary approach

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[38] Revenue earned by generators in SEM from energy, capacity and constraint payments between 2008-2015 was 75 %, 20 %, and 5 % respectively (Eurostat, 2016)

[39] Cambridge Economic Policy Associates when reporting on market power and liquidity on behalf of the RAs, found that the Bidding Code of Practice has been an effective mitigating factor of market power (Cambridge Economics Policy Associates, 2010)

[40] EirGrid in the Republic of Ireland and their counterpart System Operator of Northern Ireland in NI. EirGrid acquired their Northern Irish counterpart in March 2009.

[41] ESB Networks along with ESB Electric Ireland (replaced ESB Customer Supply) and ESB Generation and Wholesale Market (replaced ESB Power Generation) became legally separate entities in February 2009 as part of the unbundling process outlined in the EU energy packages.

[42] The Third Energy Package: European Union 2009 Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009, concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC.

to full market integration using clear rules for implementation (network codes[43]), market coupling initiatives (multi-regional coupling) along with structuring the necessary power exchanges and systems to operate the various power markets (i.e. forward, day-ahead, intra-day, balancing markets) (ENTSO-E, 2014).

The primary aim of the Target Model is to maximise social welfare gain for all market participants, i.e. maximise consumer and supplier surpluses. Using the “copper plate” effect outlined by Barroso et al. (2005), the internal market is based on a principle where electricity generated in one area is consumed in another without geographical or market-based constraints; causing a price equilibrium across the region. It was acknowledged by the European authorities that for this to transpire, full utilisation of interconnection capacity between price zones was vital for any future integration plans. This barrier was addressed in the Capacity Allocation and Congestion Management[44] network code that promotes economically-driven power flows on interconnectors which, as pointed out by McInerney and Bunn (2013), has not always occurred. By lowering technological and institutional barriers, such as the previous example, electricity markets across Europe could be fully coupled as has been the case in the Nordic region since 1990 (Olsen, 1995).

2.4.3.1 The Integrated Single Electricity Market

The SEM is known for its transparency and as a highly functional, effective pool-based market that works in the interest of consumers according to Gorecki (2013). Nevertheless, it must transform to comply with the Third Energy Package. After receiving various derogations on implementing the Target Model due to its unique situation of being an “*island system with central dispatch*” (Agency for the Cooperation of Energy Regulators, 2011, Section 1.2), SEM must become compatible with the greater European electricity market in 2018.

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[43] Network codes were developed by the European Commission, Agency for Energy Regulators and the European Network of Transmission System Operators to provide guidelines for the internal energy market to trade energy (ENTSO-E, 2014).

[44] For more details, see the Capacity Allocation and Congestion Management Report from the European Network of Transmission System Operators for Electricity (ENTSO-E) which outlines Network Codes for use in the internal market (European Commission, 2015a).

Transforming SEM to become compatible with electricity markets across Europe involves restructuring its forward, day-ahead, intra-day, and balancing markets. Notwithstanding the fact that the new version of SEM, known as the Integrated Single Electricity Market (I-SEM), will remain centrally dispatched, it will also be more onerous on market participants in terms of hedging risk exposure through forward contracting and implementing bidding strategies. In I-SEM the aforementioned safeguards to risk exposure, i.e. Uplift and Make Whole Payments, will no longer exist, therefore participants need be more active in both forward and intra-day market trading; neither of which are currently very liquid in SEM. Add in a new suite of system services[45] along with the latest iteration of a capacity mechanism based on financial options,[46] and Ireland's electricity market is set to evolve from what was a straightforward bilaterally traded energy market into the multidimensional, complex instrument.[47,48]

2.5 The role of climate mitigation policy

In addition to the EU energy packages, EU climate mitigation policies on renewable energy, greenhouse gas emissions reduction and air pollutant limits also impacted on the electricity sector as the Member States were required to make a concerted effort to be sustainable. For instance, the EU Directive 2001/77/EC[49] established a target for Ireland to achieve 13.2% of gross electricity consumption from renewable energy sources by 2010. Similarly, the 2020

[45] The "*DS3 - Delivering a Secure, Sustainable Electricity System*" programme strengthens, and doubles the number of, ancillary services in place to fourteen. DS3 aims to facilitate increased levels of variable renewable generation on the island of Ireland to ensure compliance with Article 16 of Directive 2009/28/EC (duty to minimise curtailment of renewable electricity), helping to reach binding Member State renewable energy targets by 2020. For more information, see: (EirGrid & SONI, 2011)

[46] The Capacity Remuneration Mechanism as it is known, will take the form of a volume-based reliability options mechanism that operates in a similar way to a financial call option or one-way contract for difference. For more information, see: (Single Electricity Market Committee, 2015c, 2016a, b)

[47] See the following decision papers from the RAs for further details: (Single Electricity Market Committee, 2013, 2015a, b, c, 2016a, b)

[48] This market evolution may turn out to be a big winner for software development houses as was the case in Britain with the implementation of the New Electricity Trading Arrangements in 2001 which ended up far over budget costing approximately US$2 billion, according to Thomas (2004)

[49] European Union 2001 Directive 2001/77/EC of the European Parliament and of the Council on the Promotion of Electricity from Renewable Energy Sources in the Internal Electricity Market.

Climate and Energy Package set three targets for 2020 for the EU: to achieve a 20% renewable energy share of gross final consumption; to reduce greenhouse gas GHG emissions by 20% compared to 1990 levels and; to improve energy efficiency by 20% compared to 2005 levels. The renewable energy target from the Climate and Energy Package was subsequently transmitted into individual Member State targets in EU Directive 2009/28/EC.[50] To achieve Ireland's 16% target, the government set individual sectoral targets for renewable electricity (40%); renewable heat (12%) and renewable transport (10%). The 2010 and 2020 targets for renewable electricity have driven the acceleration of wind farm deployment in Ireland, supported through market support mechanisms.

The EU greenhouse gas emissions target was separated into two separate targets. EU Directive 2009/29/EC[51] on emissions trading set a target of 21% reduction by 2020 relative to 2005 levels for large point source emitters who are in the EU Emissions Trading Scheme (ETS) and a 10% reduction by 2020 relative to 2005 levels for those outside of the ETS, i.e. the non-ETS sectors. Electricity generation falls within the ETS, as most power plants are considered large point source emitters. The ETS price has been lower than anticipated and questions have been raised about its effectiveness by Muúls et al. (2016).[52] However, the ETS may have led to higher investment in carbon-neutral generation capacity. The non-ETS target has no direct impact on electricity and was distributed amongst the Member States per Decision number 406/2009/EC.[53,54]

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[50] European Union 2009 Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources

[51] European Union 2009 Directive 2009/29/EC of the European Parliament and of the Council of 23 April 2009 amending Directive 2003/87/EC to improve and extend the greenhouse gas emission allowance trading scheme of the Community.

[52] ETS reform is currently underway. The aim is to raise the price to a "cost-effective emission reductions" level that would impact on fossil-fuel based generating plants and their marginal cost of generation. ETS reform could bring about the goal of the ETS and introduce a carbon tax that will reduce the amount of emissions gradually over time, eventually leading to decarbonisation. For more information, see: (European Commission, 2015c)

[53] European Union 2009 Decision No 406/2009/EC of the European Parliament and of the Council of 23 April 2009 on the effort of Member States to reduce their greenhouse gas emissions to meet the Community's greenhouse gas emission reduction commitments up to 2020.

[54] An air pollution target was published in the EU National Emissions Ceiling Directive (Directive 2001/81/EC) which set upper limits for each Member State for the total emissions in 2010 (currently being revised to extend

2.5.1 National climate mitigation policies

Support for renewable electricity in Ireland was first introduced in the 1990s. While the Alternative Energy Requirement (AER)[55] support scheme was started in 1994, it was not until a government policy in 1996 entitled "Renewable Energy – A Strategy for the Future" that a framework was implemented to address climate mitigation measures.[56] This policy played a large role in developing the Irish wind energy sector due to the inclusion of wind energy targets up to 2010 (Department of Transport Energy and Communications, 1996). Furthermore, in 1997 ESB International estimated the potential from wind power in Ireland to be in the range of 345 TWh per year or in other words, more than 19 times the national demand of the time (ESB International and ETSU, 1997). This provided a clear impetus for policy support surrounding wind power as it could increase the nation's security of supply.

Climate mitigation policies continued to support the development of Ireland's wind energy sector, showing year-on-year growth. For instance, the "Green Paper on Sustainable Energy" published in 1999 set an ambitious target to install 500 MW of renewable energy capacity nationwide between 2000-2005. The paper outlined plans to reform the AER scheme, improve measures supporting the deployment of renewable energy, while also providing concrete proposals for market liberalisation and becoming a central feature in Ireland's greenhouse gas abatement strategy (Global Wind Energy Council & International Renewable Energy Agency, 2013). This was followed by the introduction of Renewable Energy Feed-in Tariff (REFiT) in 2006 to replace the AER scheme to further expand the sector. Through centrally administered price setting, the REFiT programme sought to increase the profitability of wind power which, according to Global Wind Energy Council & International Renewable Energy Agency (2013),

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limits to 2020) of the four pollutants responsible for acidification, eutrophication and ground-level ozone pollution (sulphur dioxide, nitrogen oxides, volatile organic compounds, and ammonia). This prompted investment in flue gas desulphurisation (reducing SO_2) and selective catalytic conversion (reducing NOx) at the Moneypoint power station in 2010.

[55] The AER was a competitive bidding process supporting alternative energy sources through a power purchase agreement of up to 15 years in duration (Global Wind Energy Council & International Renewable Energy Agency, 2013; Staudt, 2000)

[56] The main justification for the strategy was for 'security of supply' purposes. It was estimated that without developing renewables, the electricity generated from indigenous energy sources would drop from 43% in 1994 to 8% by 2011 (Department of Transport Energy and Communications, 1996)

had led to many projects not being developed as a result of low prices received under the AER competitive bidding process. Figure 2.3 demonstrates the success both support schemes achieved in terms of promoting wind power in Ireland.

2.5.1.1 Pecuniary externalities influencing market dynamics

In Ireland, the AER and REFiT support schemes are funded through a Public Service Obligation (PSO) levy that was introduced in 2003 as a means of ensuring 'security of supply' and supporting indigenous and renewable fuel sources outside of the market[57] (Commission for Energy Regulation, 2002). The levy affords units qualifying under the indigenous fuels or renewable sources categories priority dispatch in the energy market and is a prime example of a 'pecuniary externality' directly affecting the electricity market in Ireland. The three categories eligible to receive a power purchase agreement under the levy are as follows:

- **Indigenous fuels:** Three peat-fired plants with a combined installed capacity of 378 MW[58]
- **Renewables:** The renewables capacity supported in the 2015/16 PSO levy was 2210 MW
- **Security of supply:** Over 200 MW of open cycle gas turbine "peaking" capacity was afforded power purchase agreements. A 400 MW combined cycle gas turbine plant and 160 MW combined heat and power plant were awarded agreement in 2005, referred to as "Cap '05" (Commission for Energy Regulation, 2016)

Figure 2.4 shows the distribution of the total PSO levy costs (€1.59 billion) from its introduction in 2003 to the forecasted levy for the 2015/16 PSO year. The indigenous fuels category (peat) accounts for the largest share of 48%, with renewables accounting for 28% and

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[57] The RAs forecast the overall PSO cost for the following year and set the consumer levy accordingly. Ex-post calculations are carried out after the PSO year (Oct 1st to Sept 30th) has concluded to quantify any variances between forecasted and actual costs, and if necessary, reconciliation is performed when calculating the levy for following year.

[58] The International Energy Agency estimated the cost of generating electricity from peat in 1999 to be 50% higher than if using coal. It was also pointed out that subsidies in Ireland for peat were far lower than for coal in other EU Member States, such as Germany or Spain (International Energy Agency, 1999). Supporting peat for electricity generation also has socio-economic advantages in terms of local employment in areas of Ireland which are below the average employment rate (OECD, 2001).

Cap '05 accounting for 17%. Peaking and Others (administration costs) account for the remainder.

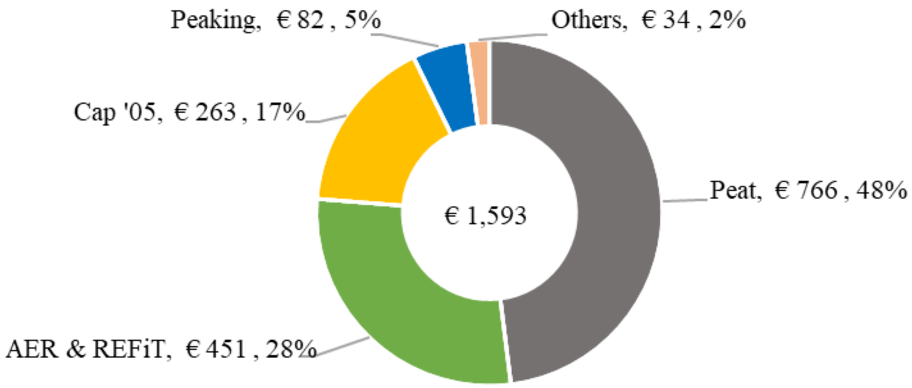

Figure 2.4: Disaggregated total cost of the PSO levy between 2003 and the 2015/16 PSO year (€millions). Source: Commission for Energy Regulation, PSO Levy Annual Reports, Dublin.

Implementing a competitive market should, ideally, limit external influences on the market, leaving costs directly associated with the product the only driver of market price, i.e. fuel and variable operation and maintenance costs. However, as awareness of environmental concerns become more prevalent and the realisation that security of supply and reliance on imported fuels are vital to economies, this may fail to materialise as some external costs are not internalised in the price of electricity. The PSO levy is a prime example of a pecuniary externality and when taken along with other external influences such as the 1970s oil crises or issues around the public acceptance of nuclear energy for example, have influenced change in the generation portfolio, as described in Section 2.3 and illustrated in Figure 2.3.

Moreover, from a market perspective, some externalities can distort entry and exit market signals. Take for instance a market based on economic dispatch; priority dispatch and renewable energy support are two influencers that can destabilise the foundations on which the market functions (Keay, 2016). When a market contains high levels of zero-marginal-cost power sources (e.g. wind or solar-based generation), the resulting SMP would be lower than if these were not included due to the 'merit order effect' as shown by (Clancy et al., 2015; Cleary et al., 2016; Sensfuß et al., 2008). Generally, lower SMPs do not affect zero-marginal-cost power sources in the same way as it would for other plants due to support mechanisms in place. However, if infra-marginal rent cannot be obtained for a 'traditional' thermal unit then fixed costs cannot be recouped without some addition mechanism such as an Uplift, Make Whole Payment or capacity payment mechanism as occurs in SEM. This aspect of market design has been recently discussed in reports by (Keay, 2016; Sen et al., 2016; Sensfuß et al., 2008) who outline a range of issues that face modern day electricity markets. Keay (2016) concludes that electricity markets in Europe may effectively be broken and questions how they must evolve to be fit for purpose again, while Sen et al. highlights the need for "*renewed thinking, or a shift in focus – in other words, a 'reform' of electricity reform*" (Sen et al., 2016, p.39). This concern goes beyond the borders of this chapter and therefore not addressed in further detail.

2.5.1.2 Outlook for Ireland's electricity sector

A recently published government policy called "Ireland's Transition to a Low Carbon Energy Future 2015-2030" may shape the electricity sector of the future in Ireland (Department of Communications Energy & Natural Resources, 2015). Aiming to transition towards a low carbon energy system while maintaining the three core objectives of sustainability, security of supply, and competitiveness, the focus of the chapter is on achieving the optimal benefits at least cost to consumers through new frameworks and pathways, consumer interaction and by promoting innovation and enterprise opportunities. From a broader perspective, the ETS reform may have the desired effect and increase the marginal cost for fossil-fuel based units in Ireland and across Europe to generate power. And finally, the various out-of-market payments made possible through EU energy policy will continue to affect market dynamics; raising concerns around its suitability to the generation portfolio of the future.

2.6 Conclusion and policy implications

This chapter highlights the role of policy in Ireland's electricity sector over the past 100 years. Numerous key transitions occurred over the period that were directly associated with policy decisions. For example, the decision to create a state-owned entity to operate, manage and maintain the sector and distribute electricity nationwide on a non-profit-making basis. In a move that would have a significant effect on the future of the sector, the ESB turned down the option of selling electricity in bulk to other distributors, instead opting to deliver electricity directly to consumers to reduce the effects of local politics and municipal boundaries on the development of a national electricity network.

Another example was the lack of policy direction in the 1950s/60s that left the nation exposed to the 1970s energy crises; exposure which resulted in a renewed focus in Irish energy policy. With the aim of increasing security of supply, Ireland attempted to reduce its reliance on imported commodities (i.e. oil) by diversifying the generation portfolio through the promotion of coal, peat, natural gas and later, wind power. Furthermore, through support mechanisms and renewable energy targets that stemmed from climate mitigation policies and security of supply ambitions, Ireland used energy policy to achieve one of the highest penetrations of variable renewable generation (wind power) in the world. Therefore, poor policy direction in one period of time provided the impetus for strong energy policy afterward.

Ireland is subject to EU legislation and through the energy packages enacted in 1996, 2003 and 2009, three distinctive phases of market transformation were initiated. First, market liberalisation occurred and had an immediate, even a pre-emptive, effect as the legacy monopolist improved overall efficiency in its preparations for the open market. Second, a new cross-border, multi-currency electricity market was created. Referred to as the all-island single electricity market (SEM), this market was found to work in the interest of consumers due to its open and transparent nature. Then again, it could also be said that the new market worked well for market participants, specifically generators, as mechanisms were in place to ensure cost recovery. Third, the final market transformation to comply with the EU Target Model; joining Ireland's electricity market to the rest of Europe. This market overhaul created I-SEM, a version of the previous pool-based market that had been shoe-horned to ensure compatibility with the regional alternative. However, as described by Gorecki; "*Aligning SEM with the Target Model appears very much to be a matter of fitting a square peg into a round hole.*" (Gorecki, 2013, p.687). I-SEM may be described as a complex multi-dimensional instrument that exposes market participants to heightened financial risk when compared to its predecessors.

EU climate mitigation policies on renewable energy, greenhouse gas emissions reduction and air pollutant limits have changed the electricity sector significantly as the Member States were required to make a concerted effort to be sustainable. The various pecuniary externalities, such as out-of-market payments for example, will continue to affect market dynamics; raising concerns around the suitability of the modern-day market to adapt to the generation portfolio of the future. However, this concern goes beyond the boundary of this chapter and may require further research later.

Broadly speaking, the evolution of Ireland's electricity sector was synonymous with developments in other countries. Increasing security of supply was key after the 'awakening' provided by the oil crises. In Irelands situation as an island state with little (electrical) interconnection, the learnings provided by this chapter regarding policy decisions surrounding the decision to create a non-profit state-owned entity, security of supply and the development of wind power should be useful for policy makers in developing nations faced with similar decisions as the ‘barriers/mistakes/shortcomings’ that confronted Ireland over the 100 years of evolution are highlighted.

Chapter 3: Reconciling high RES-E ambitions with market economics and system operation: Lessons from Ireland's power system

3.1 *Abstract*

The integration of variable generation challenges electricity systems globally. Using Ireland's electricity sector as a case study, we highlight multiple challenges in reconciling ambition for variable renewable integration with market economics and system operation. Ireland has the highest share of non-synchronous variable renewable electricity on a single synchronous power system. This case study examines the strategy being implemented to optimally balance between efficiency, flexibility and adequacy while maintaining a fully functional system that strives to adapt to evolving conditions. The transition that the Single Electricity Market underwent to comply with the EU Target Market was a major overhaul of what made the all-island market a success. Volume-based reliability options have distinct advantages over capacity payments. System services are critical for system stability and 14 separate system services are being developed. These actions, when taken together, provide an insight into the lengths to which this electricity market must go to transform from its cost-based nature to a value-based alternative that rewards flexible and reliable capacity with the ability to evolve with market conditions of the future.[1]

Keywords: EU Target Model; I-SEM; Electricity market transformation; System services; Capacity remuneration mechanism.

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[1] Published as: Gaffney, F., Deane, P., Ó Gallachóir, B. 2019. 'Reconciling high renewable electricity ambitions with market economics and system operation: Lessons from Ireland's power system.' Energy Strategy Reviews 26, Article 100381.

3.2 Introduction

In many parts of the world, the electricity sector is in the midst of technological change. Generation portfolios today are different to those of the past and will continually evolve into the future. Consequently, electricity markets are also experiencing change, a change that partially stems from the sectors' failure to effectively internalise the external costs associated with electricity generation in the past, regarding emissions. While many modern-day societies have policies in place to curtail the effects of climate change through the promotion of renewable energy and the reduction of greenhouse gas emissions (GHG), this was not always the case.

Scientists worldwide agree that global warming is occurring, and that anthropogenic greenhouse gas emissions are a leading cause. To mitigate the effects of climate change, policy measures are in place to diversify and lessen the global dependency on GHG-emitting sources. Representing the majority of all GHG emissions released globally since industrialisation, the energy sector has a large part of play in the reversal of the trend witnessed in recent decades. In the electricity sector, these climate mitigation policies can often encourage zero-marginal-cost generation (generally non-dispatchable[2] and non-synchronous[3]) through support mechanisms while discouraging fossil-fuel based capacity (typically dispatchable and synchronous) with increased marginal costs through carbon taxation; displacing the latter. When the level of displacement escalates, it can create system stability challenges for the system operators in terms of inertia, frequency and voltage response requirements (Foley et al., 2013). This can also create issues for market participants who fail to recover sufficient revenue to service debts related to fixed costs associated with dispatchable capacity; capacity which is considered important for long-term system generation adequacy (Deane et al., 2015d). In short: this situation occurs when policy measures promoting variable renewable generation push up against the limits of the system to absorb the technical characteristics of this type of electricity generation.

[2] Non-dispatchable means capacity that cannot adjust its output at will. Instead, external conditions such as wind speed or solar radiance play a defining role.

[3] A non-synchronous unit generates voltage in a waveform that is not 'in sync' with the standard used in the system.

In this chapter we use Ireland's wholesale electricity sector as a case study to demonstrate the effects of the previously mentioned displacement that results from climate mitigation policies, focusing on the planned actions/strategy to maintain a fully functional, balanced system which promotes flexibility from its market participants while remaining cost efficient and within system adequacy limits. The Irish system is an intriguing choice of case study due to its uniqueness in European terms insofar as it is an isolated system with limited storage or interconnection and yet, one of the highest levels of variable renewable generation in the region, thereby making it one of the most challenging to operate within Europe. This chapter maps out the approach taken by the Irish authorities to adapt their market and overall system to the evolving conditions, attempting to remain 'fit for purpose' in a time when many are not – a perspective shared by (Gaffney et al., 2018; Keay, 2016).

The chapter is structured as follows. Section 3.3 outlines the transformation Ireland's electricity market underwent to align its trading platforms, ex-ante pricing structures, and other aspects to ensure compatibility with the European integrated internal market for electricity and comply with the European Union's Third Energy Package.[4] Section 3.4 overviews the redesign of the capacity payment mechanism to address concerns surrounding the lack of entry or exit signals, the potential for over-compensation and the absence of a competitive edge that exist in its current form. Section 3.5 describes how the current ancillary service arrangements will be restructured to facilitate up to 75% system penetration of variable renewable generation, creating one of the most complex system service arrangements used in the electricity sector worldwide. Section 3.6 concludes the case study with some final remarks.

3.3 Transforming an energy market

Ireland transformed its electricity market to become compatible with the greater European regional market and remain compliant with the EU Third Energy Package. After receiving derogations on implementing the EU Target Model (TM)[5] due to its unique situation of being

[4] European Union 2009 *Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009, concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC*.

[5] The EU Target Model for electricity emerged in 2009 from the Florence Forum process as a blueprint with top-down and bottom-up guidance on the future market design that was deemed necessary to facilitate the EU internal market for electricity (Booz & Co. et al., 2011). Fully aligned with the three energy packages (Dir. 1996/92/EC, Dir. 2003/54/EC, Dir. 2009/72/EC), the Target Model outlines the necessary approach to complete market

an "*island system with central dispatch*" (Agency for the Cooperation of Energy Regulators, 2011, Section 1.2), the all-island electricity market became compatible with the regional day-ahead market on 1st October 2018 (Agency for the Cooperation of Energy Regulators, 2011; European Commission, 2015a). It may also be suggested that Ireland's electricity market needed to adapt to remain 'fit for purpose' as conditions within the sector evolve, both naturally and as a consequent of policy influence.

For instance, in additional to the EU Third Energy Package which primarily focuses on the internal market for both electricity and gas, EU climate mitigation policies focused on increasing renewable energy and reducing both greenhouse gas emissions and air pollution limits, also impact the electricity sector. Policies such as the 2020 Climate and Energy Package for example, set binding targets for the EU to achieve regarding the renewable energy share of gross final consumption, reducing greenhouse gas emissions and improving energy efficiency. Once transmitted into individual Member State targets via EU Directive 2009/28/EC (European Commission, 2009a), Ireland was assigned a 16% renewable share of gross final consumption target for 2020. To reach the national target, individual sectoral targets were established for renewable electricity (40%), renewable heat (12%) and renewable transport (10%). As a result, it is estimated that 5.3 GW of wind power capacity must be installed (EirGrid, 2016a), representing 33% of the anticipated total generation portfolio for the entire island to achieve the renewable targets of both jurisdictions.

3.3.1 The all-island electricity market

The all-island Single Electricity Market (SEM) was established in 2007 as the main trading platform for electricity on the island of Ireland. The cross-jurisdictional, dual-currency market was built on a centrally dispatched gross pool model that was the sole route to market for generators and suppliers alike.[6] The transition SEM underwent to comply with the TM was a major overhaul of what made the all-island market a success, both in terms of mitigating market

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integration applying clear rules for implementation (network codes), market coupling initiatives (multi-regional coupling) as well as restructuring the necessary power exchanges and the necessary systems to operate the power markets (forward, day-ahead, intra-day, balancing markets) (ENTSO-E, 2014). The model also involved harmonising information models, developing a central information platform, and actively adjusting the TM for better performance.

[6] There is a De Minimis threshold of 10 MW for generators. Units below this level could arrange bilateral contracts with suppliers in what was a residue from old support schemes for variable renewable energy sources.

power through full transparency of data and also providing a market that "*worked well for consumers in Ireland*" according to Gorecki (2013, p.677).

However, gross pool markets are often used as an intermediary step between a monopoly and a fully open bilateral market – akin to a fully open, liberalised market on training wheels according to Harris (2011). In the SEM, the 'training wheels' reference referred to the lack of risk exposure for market participants which has wider effects on the system. For example, SEM did not provide sufficient exit signals for old, inefficient capacity nor did it encourage the entry of units that added value to the system through flexibility. In other words, SEM lacked a competitive edge. This is an argument that reoccurs numerous times throughout the chapter when describing different aspects of the overall market transformation.

From a high level, Ireland's electricity market did not need to change from a pool-based design to bilateral contracts based alternative to comply with the TM, instead it needed to develop the market framework in which it occupied to be more dynamic, i.e. relying less on the 'training wheels' aspect of a pool market and introduce competition for increased system efficiency. For this development to take place, several issues needed to be addressed before any alignment could be achieved. For example, system marginal prices in SEM were set (4 days) ex-post rather than ex-ante, suppliers could not submit a demand curve, and there was no continuous intra-day market or forward market liquidity of any significance. Coupled with the knowledge that SEM was centrally dispatched as opposed to self-dispatched markets in the rest of Europe (except Cyprus), the scale of the task is evident. As summarised by Gorecki; "*Aligning SEM with the Target Model appears very much to be a matter of fitting a square peg into a round hole.*" (Gorecki, 2013, p.687).

3.3.1.1 Market transformation

With guidance (and the previously mentioned derogations) provided by the Agency for the Cooperation of Energy Regulators (ACER), the Regulatory Authorities (RAs)[7] laid out plans for the transition to become TM compliant. Through a number of decision papers, bilateral meetings, workshops and various working groups, the RAs put a programme in place to

[7] The Commission for Energy Regulation in the Republic of Ireland and the Northern Ireland Authority for Utility Regulation in Northern Ireland.

transition to the new electricity market for the island of Ireland, known as Integrated Single Electricity Market (I-SEM) (Single Electricity Market Committee, 2012). The RAs made key decisions relating to market operations when they announced the current transmission system operator (TSO)[8] as the Nominated Electricity Market Operator, a requirement under the capacity allocation and congestion management network code,[9] and on the issue of centrally- versus self-dispatched models when it was decided there would be no change on the current stance. The decision to retain the centrally-dispatched model was taken as the RAs considered self-scheduling inappropriate for SEM due to the 'lumpiness'[10] of the system and therefore believed central dispatch to be a core requirement of the all-island system (Single Electricity Market Committee, 2012).

One of the largest differences between where SEM was and where it needed to be was the design of its trading platforms. Implementing a liquid forward market, a day-ahead market with ex-ante pricing, continuously traded intra-day market and cross-border balancing market was all new territory for the all-island market. Each different market had to become acquiescent to supplier participation, along with the centrally dispatched model to be retained under the new structure. Furthermore, importing a trading platform structure compatible with the TM was only part of the task, instilling market confidence that each platform would operate 'as per design' was equally important for market success. This was especially relevant when one considers that certain platforms (i.e. forward and intra-day) may require levels of liquidity not experienced in SEM. For instance, the forward market in SEM was not utilised to its full potential for hedging medium to long-term fuel prices as witnessed in other markets around

[8] EirGrid and the System Operator of Northern Ireland (SONI) are the TSOs in the Republic of Ireland and Northern Ireland jurisdictions respectively.

[9] The capacity allocation and congestion management network code has been an important network code implemented to-date. The code promotes economically-driven electricity flows on interconnectors which, as alluded to by McInerney and Bunn (2013), does not always occurred. By lowering technological and institutional barriers around interconnectors, European electricity markets could be coupled in a similar way to that in the Nordic region since 1990 (Olsen, 1995). The code was essential when one considers the main aim of the TM is to maximise social welfare gain, i.e. maximise consumer and supplier surpluses (Newbery et al., 2016). Employing the "copper plate" effect as alluded by Barroso et al. (2005), the TM is based on the principle that electricity generated in one area can be consumed in another without constraints, causing a price equilibrium.

[10] This refers to the ratio between the largest generating unit on a system and system demand. In SEM, a large unit may represent up to 20% of dispatchable generation (Single Electricity Market Committee, 2012).

Europe. Similarly, if one considers that all market participants (including non-dispatchable generators) must be *balance responsible* in I-SEM as outlined by the Single Electricity Market Committee (Single Electricity Market Committee, 2014a, 2015b), then trading in the intra-day time frame needed to occur continuously compared to SEM's twice daily intra-day auctions – a function that helps all market participants to reduce their risk exposure. Figure 3.1 illustrates the market timelines in I-SEM.

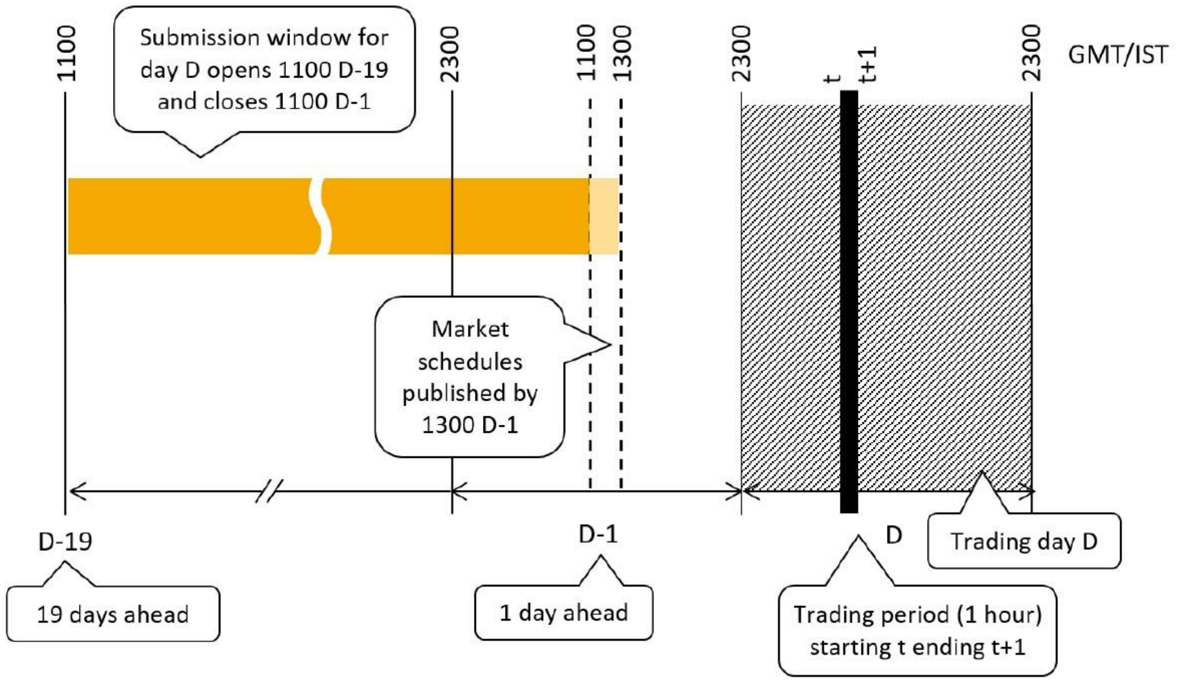

Figure 3.1: I-SEM market frame timeline.(EirGrid & SONI, 2017) Trading participants submit bids and offers in the day-ahead market for a specific day between 11:00 D-19 (19 days before delivery) and 11:00 D-1 (1 day before delivery). The market is cleared with schedules are published at 13:00 D-1. Intra-day trading opens at 11:45 D-1 and closes an hour before delivery. Balancing market timeline overlaps with the intra-day and set the imbalance price for actions taken by the TSO. SEM, on the other hand was a cost-based market that included a market schedule dispatch D-1 which set the market price. This was followed by a second dispatch schedule which accounted for system constraints and system services.

The retention of the centrally dispatched model in Ireland's new electricity market also had a bearing on how market participants approach the newly designed market platform structure. For instance, notwithstanding the fact that there will be a forward market available for hedging medium- to long-term prices, this will be financial only. To physically trade electricity, the ex-ante markets (day-ahead and intra-day) and the balancing market are the exclusive routes to market in their respective timeframes, therefore generators need to be successfully dispatched to meet any financial contractual obligations agreed in the forward market. While this does not occur in other European markets due to their ability to bilaterally trade contracts between generators and suppliers, the small scale and yet complex nature of Ireland's electricity market makes the approach important for mitigating against market power exertion from legacy firms, according to the RAs[11] (Single Electricity Market Committee, 2012). This introduces an additional level of risk for vertically integrated companies that may have hedged forward to reduce risk exposure around commodity prices for their thermal units for example, yet if their generation capacity does not get dispatched the company is fully exposed to market prices from their supply-side.

For market participants, transforming the pool-based energy market to become compatible with the TM provides greater financial risk exposure, especially electricity producers. Gaffney et al. (2017) allude to the ‘comfortable’ position in which market participants in SEM have experienced to-date in such a risk adverse market design. Through an ‘uplift’ adder on shadow prices, ‘make whole payment’ and capacity payment mechanism, both short and long run costs are likely to be recovered, which provides an attractive incentive for potential new entrants investing in the sector. Under the new market structure, a capacity payment mechanism will remain in place for a select number of participants to recoup fixed costs[12] while the other ‘safety nets’ disappear. Therefore, I-SEM will be more onerous and complex for market participants as financial risk management comes into focus. Hedging risk exposure through forward contracting along with implementing bidding strategies will be taken to a higher level than currently being applied. In other words, for the first time since market liberalisation in 2000 the electricity sector in Ireland will operate without ‘training wheels,’ leaving market participants open to risk, as is the case in a fully liberalised, dynamic, open energy market (ElectroRoute, 2016).

With this new, heightened level of risk exposure burdening market participants, along with the anticipated increase in zero-marginal-cost generation in Ireland to reach mandatory renewable energy targets, revenues earned outside of the energy market, such as capacity payments and auxiliary revenues, become even more in focus and critical for long-term economic survival.

[11] Cambridge Economics Policy Associates (2010) noted that there was “*no significant market power exercised*” in Ireland. However, market power exertion has taken place elsewhere. Details of the case against E.ON AG by the European Commission for the strategic withdrawal of capacity in German electricity market, see: http://ec.europa.eu/competition/elojade/isef/case_details.cfm?proc_code=1_39388

[12] Capacity payments in the I-SEM will be auctioned. Discussed further in Section 0.

Table 3.1 outlines the main changes addressed in this paper regarding the market transformation in the all-island electricity system, the focus of the case study.

Table 3.1: Summary of the main changes in the new market design that are addressed in this paper

	Component	Description
Energy Market	Trading Platform Transformation	Liquidity in the forwards market and continuous intra-day trading platform is expected. Ex-ante market prices will be published before delivery of power instead of the ex-post pricing used in SEM.
	Cost Recovery	No uplift mechanism or make whole payments to ensure full cost recovery in I-SEM. Introduces risk exposure for market participants and a competitive edge into the market.
Capacity Market	Reliability Options	Auction-based financial call options, akin a one-way contract for difference, provides suppliers with a full hedge against market prices. Incentivises reliable capacity.
	Administrative Scarcity Pricing	Incentivises flexible capacity to generate when a scarcity event using high prices.
System Services	System Service Products	Increasing from seven to fourteen products. Provide greater operational control when a frequency or voltage event occurs.

3.4 Redesigning a capacity mechanism

Questions surrounding the inclusion of capacity payment mechanisms in the energy sector have long since been a hotly-debated topic as alluded to by Di Cosmo and Lynch (2016). From a European electricity sector context, with future generation portfolios set to contain high levels of zero-marginal-cost variable renewable energy to achieve national and supranational targets, concern surrounding the 'missing money' problem and the overall structure of modern-day electricity market design is becoming increasingly pronounced, see publications by (Agency for the Cooperation of Energy Regulators, 2013; Buchan, 2013; European Commission, 2016a, b; Glachant and Ruester, 2014; Gore et al., 2016; International Energy Agency, 2016a; Keay, 2013, 2016; Sen et al., 2016).[13] Based on the merit-order approach and economic dispatch of units, the effect of high levels of zero-marginal-cost sources is shown to reduce system marginal prices. Consequently, lower prices mean less inframarginal rent is received by generators and marginal plants may fail to service debts related to fixed costs without some additional support; resulting in the 'missing money' problem and possibly leading to future concerns over generation adequacy.

The European Commission (2016a) recently launched an investigation into the area surrounding levels of financial support granted to electricity producers and consumers by the EU Member States to maintain sufficient generation adequacy levels. The purpose of the inquiry was to identify any unduly favourable capacity payments to providers that may have an impact on competition in the internal market and to ensure guidelines on state aid for environmental protection and energy 2014-2020 are adhered to[14] (European Commission, 2014a, 2016a, b). The interim report associated with the investigation stated that *"In principle, wholesale electricity markets (the 'energy-only' market) should be able to provide the price signals necessary to trigger the necessary investments provided wholesale prices allow fixed costs to be recovered."* (European Commission, 2016a, p.9). The report continues on to show awareness of the practicality or even the relevance of the previous statement in modern-day electricity markets where *"…[Electricity markets] are characterised by uncertainties as well as a number of market and regulatory failures which affect wholesale market price signals."* (European Commission, 2016a, p.9). To combat these 'regulatory and market failures' along with the associated generation adequacy concerns, capacity mechanisms have increased in

[13] Keay (2016) suggests that European electricity markets may be broken and discusses how they must evolve to become fit for purpose again. Sen et al. (2016) outlines the need for a *'reform of electricity reform.'* Glachant and Ruester (2014) believe the future EU electricity market may derail greatly from the effects of a large push to renewables, even leading to possible re-fragmentation without some coordinated policy frameworks around renewable supports and capacity mechanisms. Glachant and Ruester (2014) also allude to the European Commission's ability to use its power for policing state aids to only approve capacity mechanisms if the Member State devotes funds to improving its interconnection with neighbouring states.

[14] The capacity mechanism recently implemented in Britain was the first capacity mechanism to pass EU State Aid guidelines outlined in the *Guidelines on State aid for environmental protection and energy 2014-2020 ('EEAG')* (European Commission, 2014c). Since then France have received clearance to introduce a market-wide capacity mechanism (European Commission, 2016e) while Germany have also been granted permission for a Network Reserve in the southern part of the country to ensure security of electricity supply (European Commission, 2016f).

popularity across Europe with eleven EU Member States either using or planning to use some form of capacity payment (CREG, 2012; European Commission, 2016a).

However, concerns must be raised surrounding this un-unified market-by-market approach regarding capacity mechanisms which will create cross-border trade distortions where coupled markets use different approaches, e.g. an 'energy-only' market coupled with an 'energy-plus-capacity' market, or different types of capacity markets coupled. This concern is especially relevant to this case study as the GB capacity mechanism was recently suspended due to the outcome of an anti-competitiveness case taken by Tempus Energy[15]. Analysis by Gore et al. (2016) expands on this concern and quantifies, using empirical analysis, the difference between energy-only market and energy-plus-capacity markets. While the analysis finds that coupled markets work in principle, it also highlights that distributional effects are evident on interconnection flows when different capacity markets are accounted for. With the issue expected to magnify in the future as an increasing number of markets implement capacity mechanisms, a more coordinated approach throughout Europe may be necessary to help avoid negative effects on the internal market as highlighted by Gaffney et al. (2018).

3.4.1 Early capacity payments in Ireland

In Ireland, the first capacity payment scheme was introduced in 2001 to ensure adequate levels of generation capacity was in place to meet the growing demand for electricity resulting from large economic growth during the period. The Capacity Margin Payment Scheme, as it was known, supported open cycle gas turbine capacity in the Republic of Ireland, demand reduction schemes offered by the supply arm of the dominant firm and contracted capacity from a generation unit in Northern Ireland (Commission for Energy Regulation, 2005). In 2007, this was replaced by the Capacity Payment Mechanism (CPM), which, like its predecessor, was introduced to encourage new investment in the sector, thereby stimulating competition and easing generation adequacy concerns. As the first 'energy-plus-capacity' market in Ireland, the

[15] Tempus Energy Technology Limited, a UK-based demand response service provider, took a legal case against General Court of Justice of the EU related to the decision to afford certain market participants (generation units) contract lengths up to 15 years but not demand side response technologies as being anticompetitive, and therefore against EU State Aid guidelines. For more information on the case, see: http://curia.europa.eu/juris/document/document.jsf?text=&docid=207792&pageIndex=0&doclang=en&mode=req&dir=&occ=first&part=1&cid=1430154

CPM was a 'Capacity Pot' type mechanism set annually by the RAs using the Best New Entrant methodology to calculate the revenue required to recoup capital costs (net of anticipated inframarginal rent) for a hypothetical unit that represented the lowest cost per megawatt of installed capacity. Over the period 2007-2016, the pot averaged €551 million per annum[16] and broadly speaking, was distributed monthly to all generators depending on their availability for generation.

Described as a 'market-wide price-based capacity payment mechanism' by both the European Commission (2016a) and Agency for the Cooperation of Energy Regulators (2013), the CPM, along with all other mechanisms within this category, have inherent advantages and disadvantages. Di Cosmo and Lynch (2016) draw attention to a significant strength of the CPM related to the determination of the capacity pot size and its independence from any possibility of market power exertion. Since market liberalisation in 2000 mitigating against market power in a market described by Walsh et al. as "*an oligopolistic market with a competitive fringe"* (Walsh et al., 2016, p.4) has been a high priority. On the other hand, market-wide price-based capacity payment mechanisms risk over-compensating capacity providers as they rely primarily on administrative price setting and lack a competitive edge to reduce the level of remuneration received. Moreover, when a financial instrument, or specifically in the case of the CPM 'a contract for physical availability', rewards all market participants on an equal basis, it contains an innate flaw – it distorts market exit signals for old, inefficient capacity.

3.4.2 The capacity remuneration mechanism

Ireland's capacity payment mechanism has been redesigned and implemented alongside I-SEM to "*help deliver secure supplies for consumers in the all-island market, particularly with increasing variable generation*" according to Single Electricity Market Committee (2014a). The Capacity Remuneration Mechanism (CRM), as it is known, is based on volume-based reliability options (ROs) mechanism, operating in a similar fashion to a financial call option or one-way contract for difference. The quantity of each RO is set centrally and allocated through a competitive auction. The RO length can differ depending on levels of investment made by the RO holder,

[16] Available from SEM's annual market revenues available at http://www.sem-o.com/Pages/default.aspx or the PSO levy annual reports available at: http://www.cer.ie/

ranging from 1-10-year contracts. Successful RO holders, who must have the physical capacity to back-up an option, will receive an annual payment. In exchange, RO holders must refund the difference between the market reference price[17] and a pre-determined strike price[18] to suppliers via the TSO if the strike price is breached, as illustrated in Figure 3.2. Suppliers initially fund the ROs through a capacity charge levied as a fixed price per MWh of consumption during a pre-defined set of hours (Single Electricity Market Committee, 2015c). This type of mechanism allows suppliers a full hedge against market prices above the RO strike price. The principles behind reliability options are discussed in detail by Vazquez et al. (2002) and Agency for the Cooperation of Energy Regulators (2013), while specific details associated with the mechanisms' introduction in Ireland can be found in Single Electricity Market Committee (2015c, 2016a, 2016b).

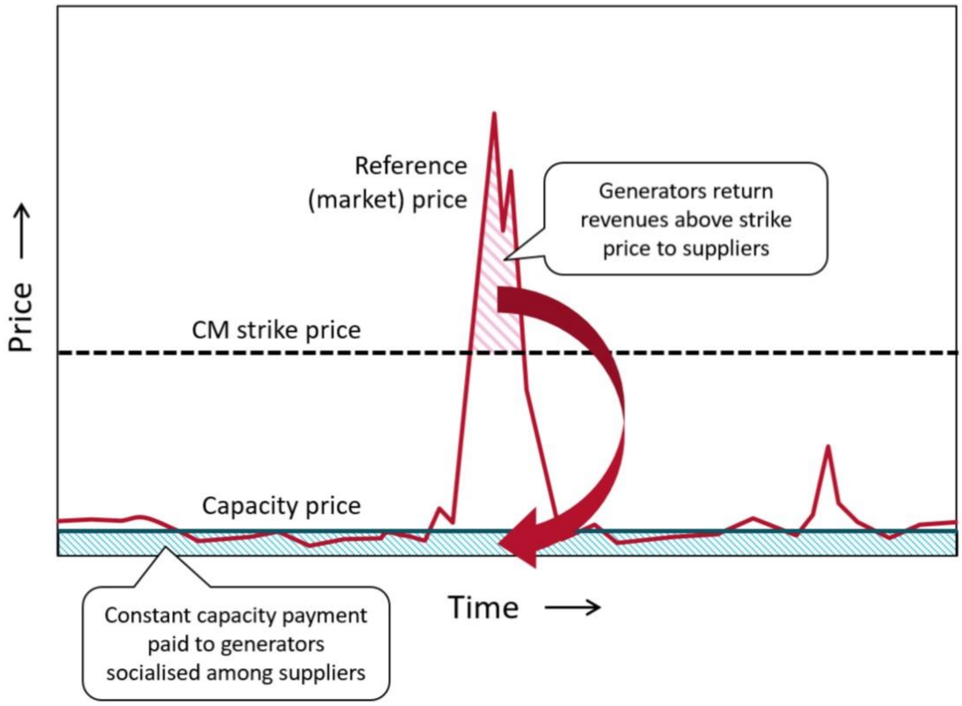

Figure 3.2: Reliability option difference payments(EirGrid & SONI, 2017)

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[17] The price obtained by the RO holder in selling their power in either the day-ahead, intraday or the balancing markets (Single Electricity Market Committee, 2015c).

[18] The Single Electricity Market Committee (2015c) propose that a hypothetical low-efficiency peaking unit using a floating strike price indexed to spot oil or gas prices will set the strike price.

3.4.2.1 Market participant eligibility

The Single Electricity Market Committee (2015c) stated that all capacity providers in I-SEM, including those receiving support, are eligible to partake in the CRM once qualification requirements outlined in the Capacity Market Code (Single Electricity Market Committee, 2017b) are adhered to. All capacity entering auctions must also apply a de-rating factor to their installed capacity that has been calculated for each specific technology type and account for the impact of plant size (Single Electricity Market Committee, 2016c). De-rating factors are based on historical performance data and under certain circumstances allow evidence for expected changes in future performance to be taken account of. Dispatchable capacity must enter the auctions while non-dispatchable capacity, once qualified to participate, can choose (Single Electricity Market Committee, 2015c). In each of the categories, de-rating factors provide reliable capacity with an advantage as higher de-ratings are associated with higher reliability, meaning a larger share of a unit's installed capacity can enter the CRM auctions.

For variable capacity where outage patterns are highly correlated, such as solar or wind power, de-rating factors are calculated based on the entire class instead of individual units. The authorities decided to include capacity receiving support to maximise competition in the CRM auctions and to remain compliant with European Commission guidelines on State Aid guidelines for environmental protection and energy which requires preference be given to capacity with lower carbon intensities in a situation where capacities are of equal technical and economic circumstances (European Commission, 2014a). While the de-rating factors may be low for variable capacity such as wind power, in Ireland's situation with a large share of installed wind power relative to the system size, the authorities expect wind power to substantially add to the competitive auction.

3.4.2.2 Administrative scarcity pricing

The CRM also includes administrative scarcity pricing in the I-SEM balancing market to provide a floor price when available capacity is lower than expected demand (plus the associated reserve requirements). It is expected that introducing scarcity pricing will increase system security through strong incentives, encourage economic efficiency, provide entry and exit signals, promote demand response and finally align with the approach taken in the British market for consistent price signals when margins are tight (Single Electricity Market Committee, 2015c). It is also hoped that implementing this type of pricing will address an aspect of SEM that has been a concern for the RAs surrounding instances where scarcity events have occurred but were not successfully conveyed in the system marginal price; an issue also experienced in the French and Great Britain (GB) electricity markets in recent times.[19] These situations may have transpired for several reasons, for example; due to the risk adverse nature of SEM, generators might not have the awareness of such events or even the ability to adapt the output of their unit over a short timeframe. Through the overall restructuring of Ireland's electricity market, it is anticipated that market participants will play a more influential role in the future (due to new level of financial and dispatch risk exposure) and, therefore, may be better positioned to react to scarcity events. In addition, the balancing market price ceiling will increase to €10000/MWh while the day ahead market cap increases from €1000 to €3000/MWh as the RAs implement the day-ahead price cap used in the majority of TM compliance markets[20] (Single Electricity Market Committee, 2015b, 2016a).

The Single Electricity Market Committee (2015c) expect scarcity pricing to incentivise new, flexible and reliable peaking generation units entering the market using the potential for high market prices at times of system stress and therefore high revenues for those in operation, as a lure. For old unreliable thermal capacity, scarcity pricing (and the reliability option approach in general) make capacity payments a riskier revenue stream for the reasons previously alluded to and also shown in Figure 3.2 where the strike price must be repaid for the volume in receipt of reliability option payment whether generating or not.

Under the new market arrangements, scarcity pricing applies when a point has been reached where available capacity is insufficient to meet demand, as illustrated in Figure 3.3. The scarcity price will start from the reliability option strike price and increase using a simple piece-wise linear function until demand is met using the operating reserve capacity or a 'lost load' event occurs[21] (Single Electricity Market Committee, 2015c).

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[19] Further details available from Single Electricity Market Committee (2015c, p.49)

[20] The Iberian day-ahead electricity market maintained its existing price range (€0–€180.30) after entering the European internal market (Henriot et al., 2013).

[21] Scarcity pricing along with other details of the CRM operational arrangements will be "*captured in and governed through, an updated Trading and Settlement Code*" which market participants must comply to according to Single Electricity Market Committee (2015c, p.6).

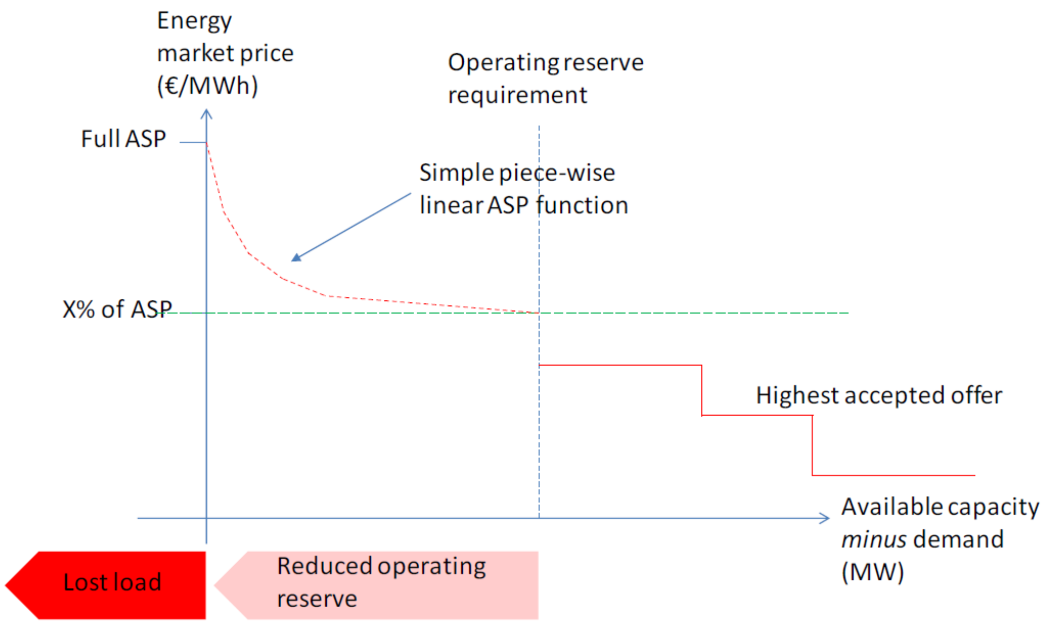

Figure 3.3: Parameterised administrative scarcity price function. Source: Capacity Remuneration Mechanism Detailed Design Decision Paper 2, SEM-16-022, Dublin. (Single Electricity Market Committee, 2016b)

3.4.2.3 Effects of the CRM

The CRM may benefit dispatchable generators over their variable counterparts. Under SEM arrangements, capacity payments were rewarded to all generators based on their availability to generate. Under the CRM, a generator must first bid for the RO, and if successful, must be available to generate when margins are tight otherwise face refunding the entire market reference price for the RO volume. Considering this, it is difficult to see the advantage for variable generators who receive out-of-market support payments bidding into CRM auctions when traditionally capacity payments were *not* mutually exclusive.

From a broader market perspective, changing capacity payments in Ireland to an RO style mechanism will address the previously mentioned concerns over 'pot' type approach regarding distorted exit and entry signals and possible over-compensation. Other benefits of pre-defined volume-based capacity auctions include the promotion of competition – providing the best value for consumers through a competitive edge, and the non-dilution of revenues when new capacity is commissioned as occurs to-date (Single Electricity Market Committee, 2016b).

3.5 Restructuring system services

Managing the all-island electricity system is a challenging task for the TSO due to the nature of the system with low levels of storage and interconnection, and yet one of the highest penetration levels of variable renewable energy in Europe. Consequently, the system operator heavily depends on reserve capacity in the form of ancillary service products as a means of ensuring system stability if the delicately balanced supply and demand relationship falters. Furthermore, with future generation portfolios expected to include increased levels of variable energy sources, this enhances the technical challenges for the system operators in terms of maintaining sufficient system inertia to preserve system stability, along with the more commonly known concerns around frequency and voltage response. The scale of the challenge faced by the Irish TSO was analysed in a suite of studies called the "Facilitation of Renewables" report (EirGrid & SONI, 2010). The findings were further refined in the "Ensuring a Secure, Reliable and Efficient Power System in a Changing Environment" report which outlined the redesign and overall strengthening of ancillary services necessary to facilitate a significant rise in the level of variable generation capacity proposed for the island of Ireland (EirGrid & SONI, 2011). The learnings from these studies are important for regions with ambition for high levels of variable renewable generation and are expanded on in Section 3.5.2 after a comparison of global systems which display similarities to that of the all-island system are discussed in Section 3.5.1.

3.5.1 Comparable system conditions

Compared to other systems worldwide, the goal of the DS3 programme regarding the facilitation of 75% instantaneous non-synchronous generation appears unprecedented on an island system with low levels of asynchronous interconnection and little energy storage. Electricity systems in New Zealand, Tasmania, and Singapore for example all have certain similarities to that of Ireland in terms of market or geographical scale. They also have either limited or no interconnection to neighbouring systems. However, none of the aforementioned have comparable levels of variable generation in their portfolios and even if this was the case, all three contain ideal technologies to accompany/facilitate variable generation with hydro-dominant portfolios in New Zealand and Tasmania and an almost exclusively gas-fired portfolio in Singapore (Energy Market Authority, 2017). For instance: New Zealand is completely electrically isolated, yet has a hydro-dominant generation mix that represented 55% of generation in 2015, providing vast amounts of flexible storage (International Energy Agency, 2017a); Tasmania has the equivalent of 16 months' worth of hydro storage capacity according to a publication by KEMA (2011), making it rather unique; while Singapore generated 95% of electricity from gas in 2016 (Energy Market Authority, 2017). Other systems such as that of the Iberian Peninsula (Spain and Portugal) and Denmark with high levels of variable generation akin to Ireland, rely heavily on hydro in the former and interconnection in the latter to facilitate variable generation. In Spain for example, approximately 20% of generation capacity is hydro-based while Denmark has nearly six times the interconnection capacity to that of the all-island system yet is of a similar size (Energinet.dk, 2016).

Notwithstanding the fact of having a much greater system size, more diversified generation mix and higher levels of interconnection, some level of comparison can be drawn to the GB electricity system in terms of frequency and voltage management, along with balancing and flexibility issues recently outlined in a National Grid (2016) publication. In recent years, the GB system has started witnessing the impacts associated with high levels of variable generation as balancing services are being utilised to a greater extent as capacity increases according to National Grid (2016). Consequently, reviews have been (or soon to be) carried out relating to numerous aspects of the overall approach to providing system services, such as; RoCoF requirements, frequency response, active network management, regional network voltage protection systems (National Grid, 2016). Other studies, such as a recent report from the SmartNet[22], that compare ancillary services from Austria, Belgium, Denmark, Finland, Italy, Norway and Spain only further exemplify the unique conditions that the all-island system deals with on a daily basis (Merino et al., 2016). While some of the previously mentioned systems have similarities to the all-island system, none endure the same rigor in terms of facilitating high variable generation with no synchronous interconnection capacity, low levels of asynchronous interconnection and little storage. Therefore, the learnings from this paper and particularly from the DS3 programme may be important for systems with ambition for high levels of variable renewable generation.

3.5.2 The DS3 programme

The “DS3 - Delivering a Secure, Sustainable Electricity System” programme was launched by the TSOs in 2011 to facilitate increased levels of variable renewables on the island of Ireland. An overview of the programme is shown in Figure 3.4, identifying the three key pillars on

[22] The SmartNet project is funded through the European Union’s Horizon 2020 research and innovation programme. For more information see: http://smartnet-project.eu/

which the programme is constructed; System Policies, System Performance, and System Tools. The figure also outlines the work streams contained in each pillar.

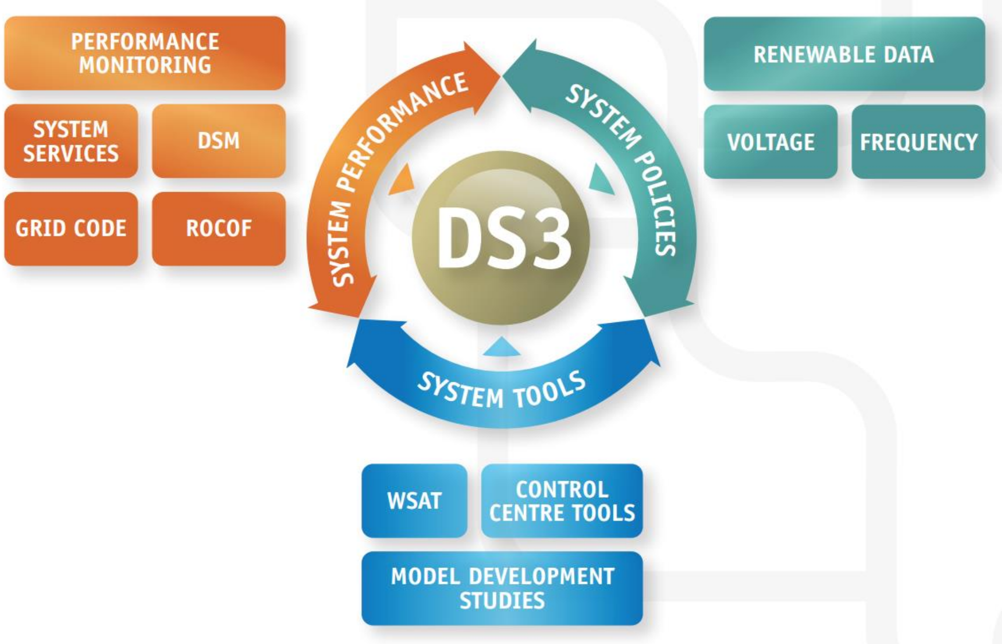

Figure 3.4: DS3 programme structure. Source: DS3 System Services Procurement Design and Emerging Thinking Decision Paper, SEM-14-108. Dublin. (Single Electricity Market Committee, 2014b)

Strengthening the existing ancillary service products while doubling their number to fourteen is a significant feat. To facilitate this transformation, the DS3 programme included the system tools and system policies pillars as key contributors to the overall system service arrangements. System tools provide control over the programme through the various means outlined in Figure 3.4 and the system policies pillar ensures the correct level of regulation is in place to support the success of DS3 through policy control. While remaining cognisant that both pillars are integral to the success of the programme, this section will concentrate on the system performance pillar and the technical aspects of the DS3 programme that may provide a financial opportunity for market participants to increase auxiliary revenue streams, thereby encouraging flexibility in the system – a characteristic which is considered essential in a system with high levels of variable generation capacity (Deane et al., 2015d).

3.5.3 System Performance

System performance relates to monitoring and managing the performance of all units connected to the all-island electricity system. Maintaining the performance level necessary to reach renewable electricity targets is important for both jurisdictions. Many changes are ongoing in this category such as Grid Code modifications,[23] developing new practices in performance monitoring and increasing the level of participation from demand side management participants. From a technical perspective, there are two critical aspects of system operation that must change for the successful adoption of the DS3 programme (Single Electricity Market Committee, 2014b). First, the Rate of Change of Frequency (RoCoF) standard that a thermal unit must 'ride-through' without disconnecting from the grid and second, the restructuring of system service products in the all-island electricity system.

3.5.3.1 Rate of change of frequency

The RoCoF standard will increase from the current 0.5 Hz per second to 1 Hz per second measured over 500 milliseconds for all conventional plants to comply with Grid Code (Commission for Energy Regulation, 2014). For synchronous generation capacity, this means their plant must stay synchronised with the system through a change of frequency of up to 1 Hz per second measured over 500 milliseconds. Increasing the RoCoF standard is not unheard of as both Spain and Denmark, two fellow Member States with significant levels of variable renewable energy, have implemented 2 Hz/s and 2.5 Hz/s RoCoF standards respectively (Australian Energy Market Operator, 2011; Energinet.dk, 2008). However, a significant difference between what Ireland aims to do compared to Denmark or Spain, is enforce the updated RoCoF standard on *all* existing thermal units, not just newly commissioned plants.[24]

In changing the RoCoF standard, the TSO anticipate that higher instantaneous penetration levels of variable renewable energy can be facilitated in the system (EirGrid & SONI, 2010). The parameter used by the TSOs to measure the instantaneous penetration of variable renewable generation is called the System Non-Synchronous Penetration (SNSP) limit. SNSP limit is calculated based on the volume of non-synchronous energy source generated plus interconnector imports as a percentage of the overall demand plus interconnector exports. In Q2 2019, at the time of writing, the SNSP limit is 65% non-synchronous energy sources

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[23] Grid code is a set of standards for all plant to adhere to that are connected to the system. For more details, see: http://www.eirgridgroup.com/

[24] This aspect of RoCoF created unrest between market participants in SEM and the authorities, i.e. the TSOs and RAs, leading to an open consultation followed by a recommendations paper on a remuneration mechanism to contribute towards costs associated with the generation studies necessary to ascertain whether a unit can meet the new RoCoF standard, for more information see: (EirGrid & SONI, 2016c).

(EirGrid, 2019). By introducing the updated RoCoF standard along with the other DS3 work streams, this limit is anticipated to reach 75% – reducing curtailment of renewable energy and therefore, helping to achieve binding EU Member State renewable energy targets. Figure 3.5 illustrates the SNSP limits anticipated by the TSO over the period 2015-2020. The figure also shows the benefit of introducing the various new/updated standards and work streams on the system in terms facilitating non-synchronous generation.

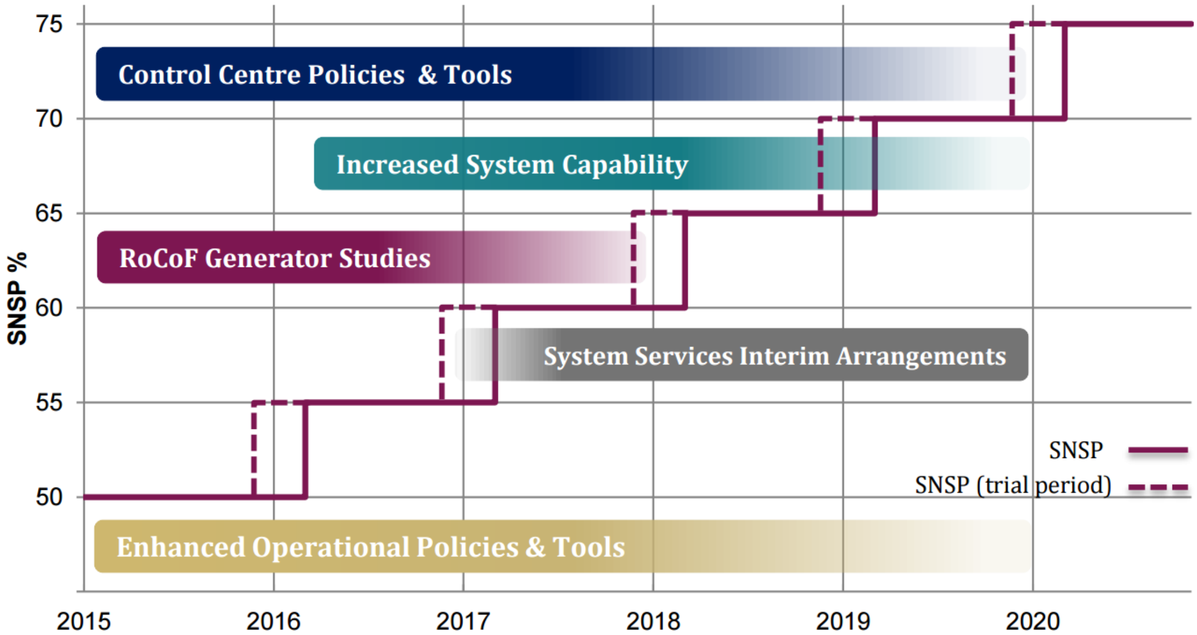

Figure 3.5: Operational capability outlook. Source: DS3 Programme Operational Capability Outlook 2016, EirGrid (EirGrid, 2016b)

3.5.3.2 System services

Maintaining a stable electricity system with as little as 580 MW[25] of asynchronous interconnection and less than 300 MW of pumped hydro energy storage is a difficult feat, especially if one considers that in 2020, the installed capacity of variable generation (i.e. wind and solar PV) is expected to be 5600 MW (EirGrid, 2016a). For comparative purposes, the peak system demand in the same year is expected to be approximately 7000 MW according to the median demand forecast for the all-island electricity system (EirGrid, 2016a). Where other

[25] The long-term view assumed by the TSOs regarding the Moyle asynchronous interconnector is that it may have an 80 MW export limit due to network constraints in GB(EirGrid, 2016a).

systems across Europe are not as geographically isolated, interconnection with neighbouring systems is a means of increasing security of supply and thus requiring fewer system services. Similarly, EU Member States such as Spain, Germany, France, Italy, and Austria have large pumped hydro energy storage capacity which is ideal for storing energy when wholesale electricity prices are low, for providing system services and for facilitating variable generation (Deane et al., 2010). Recognising that no new interconnection or storage capacity is expected in Ireland before 2025 when a proposed 700 MW interconnector to France may come online (ENTSO-E, 2015), system services remain critical for system stability.

Once the system services work stream of the DS3 programme is fully implemented in 2019, the number of system service products will increase from seven under the current arrangement to fourteen to create one of the most complex system service arrangements used in an electricity system worldwide. In October 2016, eleven of the fourteen system services became operational using regulated tariffs and volumes set by the TSOs. The three products not yet in operation are fast frequency response, dynamic reactive response, and fast post-fault active power recovery. Details of new and existing system service products are outlined in Section A of Table 3.2 while Figure 3.6 and Figure 3.7 show which of the products relate to frequency control or voltage control. The figures also allude to the ‘activation order’ timeline of products in the event of an incident.

Table 3.2: Summary of DS3 system services products

Section A					Section B
Service Name	**Abbreviation**	**Unit of Payment**	**New or Existing**	**Short Description**	**Tariff Rates (€)**
Synchronous Inertial Response	SIR	MWs^2h	New	(Stored kinetic energy) * (SIR Factor - 15)	0.0050
Fast Frequency Response	FFR	MWh	New	MW delivered between 2 and 10 seconds	2.16
Primary Operating Reserve	POR	MWh	Existing	MW delivered between 5 and 15 seconds	3.24
Secondary Operating Reserve	SOR	MWh	Existing	MW delivered between 15 and 90 seconds	1.96
Tertiary Operating Reserve 1	TOR1	MWh	Existing	MW delivered between 90 seconds and 5 minutes	1.55
Tertiary Operating Reserve 2	TOR2	MWh	Existing	MW delivered between 5 minutes and 20 minutes	1.24
Replacement Reserve (De-Synchronised)	RRD	MWh	Existing	MW delivered between 20 minutes and 1 hour	0.56
Replacement Reserve (Synchronised)	RRS	MWh	Existing	MW delivered between 20 minutes and 1 hour	0.25
Ramping Margin 1 Hour	RM1	MWh	New	The increased MW output that can be delivered with a good degree of certainty for the given time horizon.	0.12
Ramping Margin 3 Hour	RM3	MWh	New		0.18
Ramping Margin 8 Hour	RM8	MWh	New		0.16
Fast Post-Fault Active Power Recovery	FPFAPR	MWh	New	Active power >90% within 250ms of voltage >90%	0.15
Steady-state Reactive Power	SRP	MVArh	Existing	MVAr capability * (% of capacity that capability is provided)	0.23
Dynamic Reactive Response	DRR	MWh	New	MVAr capability during large (>30%) voltage dips	0.04

Sources: Section A: DS3 System Services Technical Definitions Decision Paper, SEM-13-098. Dublin. (Single Electricity Market Committee, 2013) Section B: DS3 System Services Tariffs and Scalars, Dublin. (Single Electricity Market Committee, 2017a).

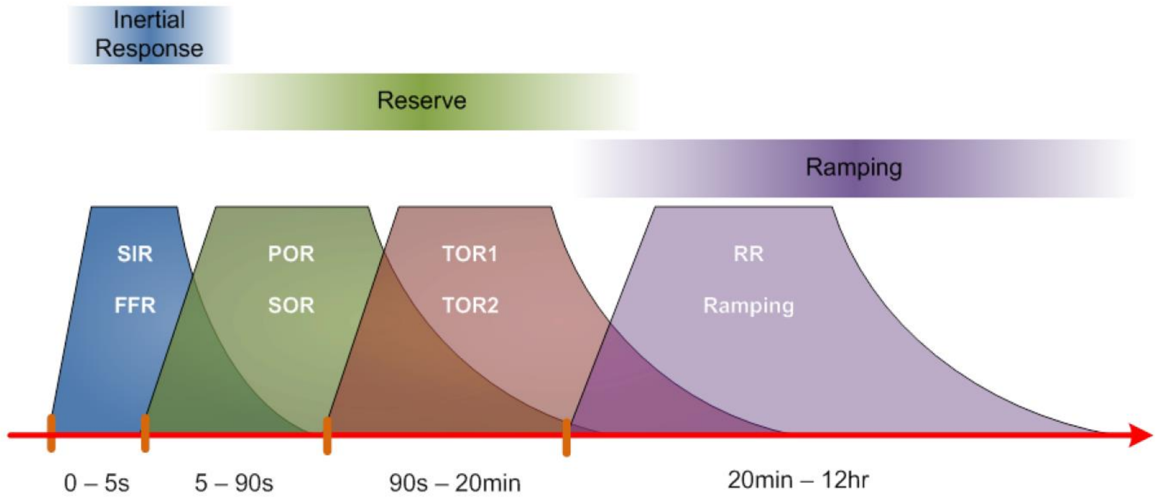

Figure 3.6: Frequency control services. Source: DS3 System Services Technical Definitions Decision Paper, SEM-13-098. Dublin. (Single Electricity Market Committee, 2013)

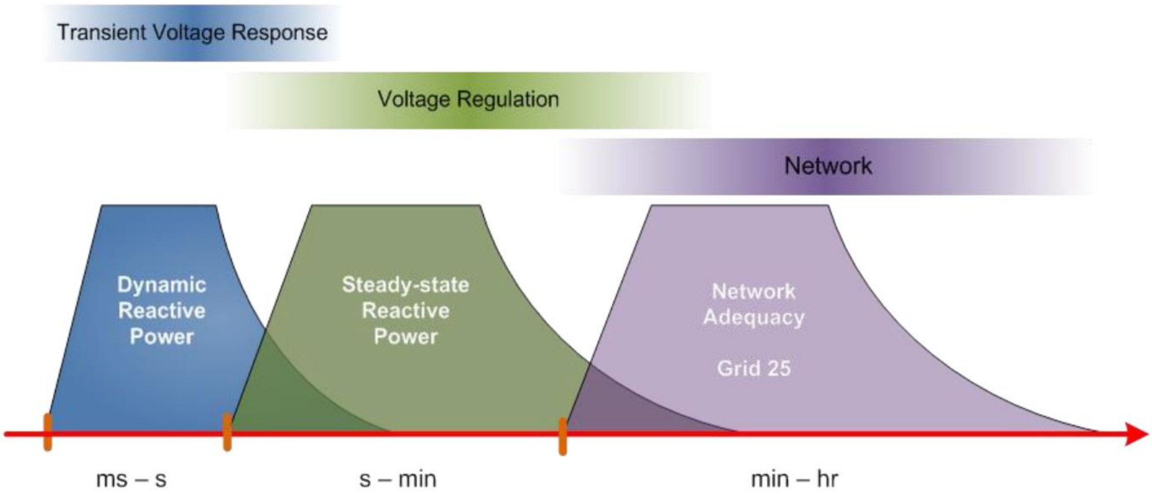

Figure 3.7: Voltage control services. Source: DS3 System Services Technical Definitions Decision Paper, SEM-13-098. Dublin. (Single Electricity Market Committee, 2013)

Figure 3.6 and Figure 3.7 demonstrate how the new system services complement the existing products in order to improve system frequency and system voltage control respectively. Each figure shows that additional products have been introduced between the time an incident occurs and when the existing products activate which allows greater operational control over the system, in turn increasing the system's ability to facilitate variable generation. For example, SIR and FFR provide an inertial and fast-acting MW response from 0-5 seconds of a frequency event occurring. Similarly, dynamic reactive response is important for system stability when there are high levels of variable generation online to deliver a reactive current response for voltage dips in the period before the existing steady-state reactive power product becomes active. Fast post-fault active power recovery (FPRAPR) is the only new product not represented on either Figure 3.6 or Figure 3.7. The FPRAPR product provides a positive contribution to system stability and security through its ability to mitigate against the impact of large frequency disturbances through fast power recovery response.[1]

Prospective providers of one or more system services outlined in Table 3.2 are required to complete a qualification trial process to 1) assess their technical ability to provide the product in question, 2) advise authorities on the level of competition for each product, and 3) establish the current capabilities within the system (Single Electricity Market Committee, 2014b). The qualification trials are carried out to assess the ability of a range of technologies to provide the various products, as described by EirGrid & SONI (2016b). All technologies, including wind power, demand side, and other technologies such as battery storage, solar PV, flywheels, etc., along with conventional generation are admissible to the trials. Once qualified, prospective providers must enter successful bids for each system service at product auctions to become a provider. Contracts for each product will be awarded on an annual basis except in the case where investment is necessary to provide a service where on a case-by-case basis contracts of up to 20 years may be bestowed on the participant[2] (Single Electricity Market Committee, 2014b). The volume of each product described in Table 3.2 will be determined annually by the TSO (EirGrid & SONI, 2016d).

In the event of low market participation or where the possibility for market power exertion exists, the contract price may be defined via a TSO set regulated tariff. The authorities suggest that applying regulated tariffs will not be the enduring solution in I-SEM, instead expect a competitive process to be in place in the long-term. Regulated tariffs will be calculated using a "cost-plus" approach which incorporates the previously defined Best New Entrant approach and a regulated rate of return aspect as described by EirGrid & SONI (2016a). Bearing in mind the need to send the correct investment signals to market participants, the authorities will set all regulated tariffs for a period of five years once the system services are fully implemented

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[1] For further details on the technical characteristics of FPFAPR and the other products, see (Single Electricity Market Committee, 2013).

[2] A potential conflict of interest was raised by market participants relating to the TSOs' ownership of a 500 MW interconnector to Great Britain that can provide system services. The SEM committee found that as the interconnector was financed by the Irish energy consumer, it should therefore be used in a means that maximises the value to the consumer. Therefore, the interconnector will not participate directly in any auctions and will be treated as a price taker for its volume. Effectively the volumes to be auctioned will be net of the provision the interconnector can provide. (Single Electricity Market Committee, 2014b)

(Single Electricity Market Committee, 2014b). In a move that is intended to provide greater certainty for the industry, the authorities stated that *"[Regulated tariffs may] provide guidance on the prices that may result from the competitive process."* (Single Electricity Market Committee, 2014b, p.35)

Section B of Table 3.2 outlines the regulated tariffs for the operational DS3 system services along with the products yet to be implemented, i.e. fast frequency response, dynamic reactive response, and fast post-fault active power recovery. These tariffs allow an insight into the potential revenue to be earned by generators for providing system services. The price received by market participants for providing system service products is also subject to scalars in an attempt to increase performance of the procurement design by rewarding providers who 'turn up' in times of most need. The scalars are based on performance, scarcity, product and volume (Single Electricity Market Committee, 2014b).

3.5.4 Revenues from DS3 programme related activities

While the updated RoCoF standard will be a requirement for thermal units under Grid Code, there is no direct revenue to be earned from having the ability to "ride-through" a frequency event. Indirectly, however, achieving the standard may ensure that a unit has a higher number of operational hours over a unit still to comply with the standard change for system stability reasons. System services on the other hand, do provide a direct revenue stream as shown in Section B of Table 3.2. Through the DS3 programme and its associated 75% SNSP target, the TSO estimated the annual benefit of reducing variable renewable energy curtailment to be in the range of €177 million by 2020 – in other words, the TSO expects the overall energy market costs to reduce by that amount (Single Electricity Market Committee, 2014b). When taken along with the existing expenditure cap on ancillary services (€60 million), the total is rounded to €235 million and used as the annual 'cap' for system services from 2020 onwards (Single Electricity Market Committee, 2014b). From a high-level view, Figure 3.8 illustrates the anticipated redistribution of revenue streams estimated the RAs in the "DS3 System Services Procurement Design and Emerging Thinking" publication (Single Electricity Market Committee, 2014b).

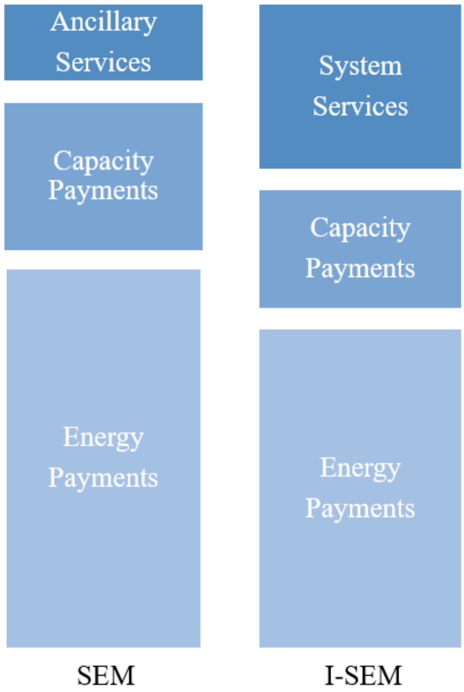

Figure 3.8: Rebalance of revenue streams. Source: own elaboration based on Single Electricity Market Committee (2014b)

3.5.4.1 Redistribution of revenue streams

Participants in Ireland's electricity market have already witnessed a change in their revenue streams over the past number of years and this trend is expected to continue through the transition to I-SEM and beyond while policy measures influence the generation portfolio. Between 2007 and 2016 for example, the total annual energy payments in SEM decreased by 49% (€2.7 to €1.37 billion)[3] while other payments, such as capacity payments, remained relatively constant (Single Electricity Market Operator, 2016). The RAs have shown awareness of the changing marketplace through their central involvement in the restructuring process to facilitate future generation portfolios in the new design for the island of Ireland. Notwithstanding the fact that revenue streams are naturally rebalancing as generation portfolios evolve, the transformation under I-SEM (including the capacity and system service elements)

[3] The 2016 annual energy market revenue is 32% below the nine-year average. It is recognised that fuel and emission costs have a part in this reduction; however, the effect of high levels of zero-marginal cost generation on lowering system marginal prices has been shown in numerous articles such as (Clancy et al., 2015; Cleary et al., 2016; Sáenz de Miera et al., 2008; Sensfuß et al., 2008). For more information on the annual market revenues, see: (Single Electricity Market Operator, 2016)

takes a significant step to what future electricity market designs may look like worldwide – optimally balancing efficiency, flexibility and system adequacy.

As demonstrated in Figure 3.8, I-SEM consists of three primary revenue streams for market participants. With future energy payments expected to reduce because of large volumes of zero-marginal-cost variable renewable energy being installed to meet renewable targets, thermal generators operating purely on the energy market may not receive sufficient inframarginal rent to service debts related to fixed costs, i.e. the missing money problem. Furthermore, as outlined by Deane et al. (2015d), many of these generators are vital for the long-term operation of the system, in terms of meeting system adequacy requirements, providing flexible generation, inertia requirements, voltage and frequency response. To address this concern, I-SEM is more value-based than its predecessor – rewarding generators that add flexibility and reliability to the system. Through the DS3 programme for example, flexible units benefit from the increased number of system service products that can be availed of, along with scalars based on performance, scarcity, product and volume. In the CRM both reliability and flexibility are rewarded as the former is a key characteristic of any such financial option-based mechanism and the latter, an advantageous characteristic when administrative scarcity pricing is in place.

3.6 Conclusion

Climate mitigation policies are influencing generation portfolios. With technological change comes both, sectoral and market change. Pecuniary externalities such as support mechanisms and carbon taxes, introduced via policy measures, can distort market price formation and affect system operations. Through this case study, the other side of the coin is observed. The paper explores the strategy used by an isolated system with high levels of variable renewable generation to optimise the balance between efficiency, flexibility and system adequacy while maintaining a fully functional system that strives to adapt to the evolving conditions.

This case study highlights several concerns that are soon to be or are already, relevant to a wide range of electricity markets. Technical issues relating to frequency and voltage control, market issues around decreasing system marginal prices – leading to the 'missing money' problem, and institutional issues concerning Ireland's need to become compatible with the greater European internal electricity market, all offer an insight into both internal and external policy influences that manifested themselves in the 2018 market transformation. This paper also demonstrates the length at which Ireland will go to achieve ambitious energy-related policy decisions to curtail the effects of climate change.

Implementing the energy market changes alluded to in Section 3.3 instils a competitive edge that entices market participants to play a more influential/central role in the future marketplace while attempting to reduce financial risk exposure. Withdrawing the reassurance of fully cost recovery creates a situation where the "training wheels" have been removed and competition can prosper. Redesigning the capacity mechanism also fosters competition through the auctioning of reliability options. The in-coming mechanism addresses concerns surrounding distorted entry and exit signals, over-compensation, and the dilution of revenues associated with new capacity being commissioned, through a pre-defined volume-based capacity auction that promotes flexible and reliable capacity. Restructuring system services increases the operational ability to control frequency and voltage during an event through additional system service products, a new RoCoF standard and a range of other inputs from the DS3 programme, as described in Section 3.5. In short; restructuring system services aims to increase operational control of the system which equates to heightened system stability, thereby improving the system's capacity to facilitate higher levels of variable generation. The actions, when taken together, provide an insight into the lengths to which this electricity market must go, to transform from its cost-based nature to a value-based alternative that rewards flexible and reliable capacity with the ability to evolve with market conditions of the future.

Chapter 4: Consumption-based approach to RES-E quantification: Insights from a pan-European case study

4.1 *Abstract*

The nexus between renewable electricity (RES-E) generation and interconnection is likely to play a large part in future de-carbonised power systems. This chapter examines whether RES-E shares should be measured based on consumption rather than production with a European case study presented for the year 2030. The case study demonstrates the volume and scale of RES-E transfers and shows how countries have differing RES-E shares when comparing those derived based on the traditional production-based approach to the alternative. The proposed consumption-based approach accounts for RES-E being imported and exported on an hourly basis across 30 European countries and highlights concerns regarding uncoordinated support mechanisms, price distortions and cost inequality. These concerns are caused by cross-border subsidisation of electricity and this work proposes that an agency be appointed to administer regional RES-E affairs. This agency would accurately quantify RES-E shares and remunerate producers from the country that consumed their electricity instead of where it has been produced – policy would be enhanced by enabling more equitable and optimal electricity decarbonisation.[1]

Keywords: EU Target Model; Consumption-based renewable electricity quantification; Member State RES-E targets; Cross-border subsidisation.

[1] Published as: Gaffney, F., Deane, J., Collins, S. & Gallachóir, B. Ó. Consumption based approach to RES-E quantification: Insights from a Pan-European case study. Energy Policy 112, 291-300 (2018).

4.2 Introduction

Globally, power sector portfolios are undergoing a technology transformation with the ambition of achieving long-term carbon-neutrality. The Paris agreement of 2015, signed by 195 countries, is a significant driver of technological change as a concerted effort is needed to limit greenhouse gas emissions in order to keep global temperatures ‘well below’ 2°C above pre-industrial levels (European Commission, 2015b). The European Union’s (EU) Emissions Trading Scheme (ETS) as well as various climate and energy packages are policy instruments that promote the decarbonisation of the energy system through incentivising emissions reduction, increasing energy efficiency and increased deployment of renewables. Higher levels of variable renewable electricity (RES-E) can pose challenges for power system operation as they produce non-synchronous and non-dispatchable electricity (i.e. wind, solar, wave, tidal) (Schaber et al., 2012). These challenges can be mitigated to a certain extend by interconnection to neighbouring systems (Booz & Co. et al., 2013; Denny et al., 2010). Furthermore, as renewable generation grows, there is an increasing likelihood that RES-E may be exported to neighbouring countries during periods of excess power. While the authors are cognisant that ‘*an electron is an electron’* no matter how it is generated, it is also recognised that RES-E targets in many regions do, in fact, differentiate between electrons – by source.

EU Member States for example, must achieve renewable electricity targets based on “*the quantity of electricity produced in a Member State from renewable energy sources*” as a proportion of Gross Final Consumption (GFC),[2] as stated in Article 5(3) of the Renewable Energy Directive (2009/28/EC) (European Commission, 2009a). Applying a production-based approach is sensible in an isolated, closed system where electricity production must equal consumption; meaning all renewable electricity is consumed domestically. However, interconnector transfers and planned increases in capacity[3] are playing an increasingly

[2] The GFC of electricity is, for the purposes of RES-E calculations, defined as: “Gross electricity production from all energy sources (actual production, no normalisation for hydro and wind), excluding the production of electricity in pumped storage units from water that has previously been pumped uphill; plus total imports of electricity; minus total exports of electricity.” Eurostat (2015, p.10)

[3] Interconnection capacity targets for Member States are 10% and 15% of installed electricity production capacity by 2020 and 2030 respectively. (European Commission, 2017a)

important role in today's European power system, i.e. making it easier to share renewable electricity surpluses and improving the operational control of a system. Equally a patchwork of varying national support schemes for renewable generation has led to situations where renewables are built where support is the strongest, rather than where the most cost-effective. Consequently, transfers of renewable electricity across interconnectors can present situations where the costs of renewable electricity are subsidised in one country and consumed in another. This therefore begs the question whether a consumption-based accounting approach to quantifying renewable electricity, which considers these transfers, should be used?

The Renewable Energy Directive already acknowledges that it is appropriate to facilitate the consumption of energy in one Member State which has been produced from renewable sources in another in order to meet defined targets in a cost-efficient manner. The directive proposes flexibility measures in the form of statistical transfer and joint projects between Member States to facilitate this. However, Member States have so far not engaged in these schemes with just two exceptions: Sweden and Norway (non-EU Member State); and Denmark and Germany (International Energy Agency, 2016b). Uncoordinated financial support schemes have the potential to cause price distortions between neighbouring countries which can lead to electricity transfers that do not provide societal gain and potentially cause cost inequalities as RES-E supported in one country is consumed in another, raising questions around 'who pays the difference between the market price and support scheme strike price?' Viewing renewable generation from a consumption-based standpoint delivers a different perspective on the intricacies involved in electricity generation and transmission. Identifying the movement of RES-E between countries opens 'Pandora's box' in terms of accounting for RES-E shares, costs inequalities associated with transferred RES-E and potential price distortions, but it also sheds light on whether the current production-based approach is 'fit for purpose' in a future de-carbonised electricity sector.

In this chapter, a consumption-based approach for quantifying a country's RES-E share is proposed and implications for renewable support schemes are discussed. The methodology is based on the concept of measuring the RES-E that is physically consumed within a country's boundary rather than what is produced. Accounting for interconnector inflows and outflows is a fundamental part of the methodology that provides the key difference between this and a traditional 'production-based' approach. The proposed consumption-based approach is demonstrated using the European internal market for electricity (hereafter; EU Target Model) as a case study for a single year. Note that under the Renewable Energy Directive for example, consumption-based measurement of renewables is used for the transport and heating & cooling sectors.

Using PLEXOS® Integrated Energy Model, a European electricity model for 2030 is created based on the recent European Commission's Reference Scenario (Capros et al., 2016). Once simulated, the results are post-processed to determine the country[4] where RES-E is produced and more importantly, where it is consumed, on an hourly basis. In doing so, issues associated with mass RES-E transfer across Europe are captured, such as uncoordinated support schemes, price distortions and cross-border subsidisation. These insights allow an in-depth discussion on the challenges and the institutional structures that need to be addressed to achieve a low carbon power system.

While many publications concentrate on topics such as the production-based versus consumption-based quantification question relating to embodied greenhouse gases in goods and services (Fan et al., 2016; Fowlie and Cullenward, 2018; Ji et al., 2016; Larsen and Hertwich, 2009; Peters, 2008; Shao et al., 2016; Simas et al., 2017; Wiedmann, 2009), the facilitation of RES-E in power systems (Cleary et al., 2016; Collins et al., 2017; Daly et al., 2015; Deane et al., 2015b; EirGrid & SONI, 2010, 2011; Fraunhofer IWES, 2015; Gaffney et al., 2019b; Henriot et al., 2013; McGarrigle et al., 2013) and/or the importance of border trade (Bahar and Sauvage, 2013; Booz & Co. et al., 2013; Denny et al., 2010; EirGrid & SONI, 2010; EURELECTRIC, 2016; Fraunhofer IWES, 2015; International Energy Agency, 2016a) regarding their respective place in a future decarbonised electricity system, few publications focus on the quantification requirements when both RES-E integration and cross border trade are taken together.

California's carbon leakage issues bear similarity to those alluded to this chapter, where out-of-state emissions are increasing due to cap-and-trade emissions scheme within state (Caron et al., 2012; Fowlie and Cullenward, 2018). The concept of resource shuffling caused by uncoordinated climate mitigation measures in California for example, is synonymous with the concerns expressed in this analysis. Ji et al. (2016) also highlight concerns surrounding

[4] "Country" is preferred over "Member State" as not all countries in the model are part of the European Union, i.e. Norway and Switzerland.

electricity traded between power systems and the characteristics associated with the transfer. Focusing on the greenhouse gas emissions aspect of traded electricity, Ji et al. (2016) outline a high-level proposal to account for both direct and in-direct emissions that widens the boundary under consideration when addressing the concern. This approach also aligns with that of California where imports were assigned an emissions factor depending on their source, or a default value if source was unknown (Fowlie and Cullenward, 2018).

Building upon this concept of 'broadening the boundary under consideration,' we present a test case that highlights: 1) the short-comings of a production-based approach in interconnected systems with high levels of renewables; 2) challenges and potential solutions for the European internal market in 2030; and 3) concerns over pecuniary externalities caused by cross-border subsidisation and uncoordinated support schemes which can lead to issues surrounding effects on investment signals and long-term security of electricity supply problems.[5]

The chapter is structured as follows. Section 4.3 outlines the methodological approach and assumptions used during the analytical phase of the chapter. Section 4.4 overviews the main results from the analysis, while Section 4.5 discusses various potential impacts associated with the proposal along with considerations related to its implementation. Section 4.6 concludes the chapter with some final remarks.

In an effort to promote transparency, the PLEXOS® model and the excel tool used to calculate renewable electricity flows, along with all associated data have been made freely available online for academic research here.

4.3 Methodology

The methodology applied combines a soft-linking approach between energy system and power system models, as described by Deane et al. (2012), with a post-processing phase to ascertain the volume of RES-E that is both produced and consumed in each country included in the

[5] Mechanisms such as uniform carbon pricing and locational marginal pricing (LMP) for example, can offer solutions to issues akin to those alluded to in this chapter. Uniform carbon pricing for instance, can help solve carbon leakage-type issues by addressing the geographical element which is central to the problem. LMP can evaluate market power, reduce transmission constraints, et cetera, all within a single price setting region. However, with this specific concern, uniform carbon pricing is already in situ and LMP would not solve the concern alluded to in this chapter regarding cross-border subsidisation.

analysis. First, the European Commission's Reference Scenario is soft-linked to a power system model comprising of 30 European countries (EU-28 Member States,[6] Norway and Switzerland) focusing on the year 2030. Post-processing is carried out on an hourly basis, in line with the EU Target Model day-ahead market scheduling algorithm known as EUPHEMIA.[7] This analytical phase will address the phenomenon known as 'wheeling', where electricity may be traded through one country to access another, based on wholesale market price differentials. Through analysis of the data it is possible to separate the share of interconnector flows subject to 'wheeling' compared to that derived directly from the country in question.

4.3.1 Power system simulation

PLEXOS® Integrated Energy Model (PLEXOS®) is a power system modelling platform used for power and gas market modelling (Drayton et al., 2004). The software is a unit commitment and economic dispatch modelling tool that optimises at least cost the operation of the electricity system over the simulation period at high technical and temporal resolution whilst respecting operational constraints. Version 7.4 (R02) of PLEXOS® was operated on a Dell Inspiron CN55905 laptop with a 6th Generation Intel® Core i7-6500U Processor. The MOSEK solver was used to simulate the model with Rounded Relaxation unit commitment applying a 0.01% relative gap and 6-hour look-ahead[8]. Using hourly dispatch, in line with the EU Target Model day-ahead market scheduling platform, 365 days were simulated to replicate 2030, taking 1.5 hours to complete.

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[6] At the time of writing, the United Kingdom remains a constituent of the European Union.

[7] Acronym: '*EU Pan-European Hybrid Electricity Market Integration Model*.' For more information on the EUPHEMIA algorithm, see the developer (N-SIDE) or operator (EPEX Spot, 2016)

[8] A look-ahead period provides the user with a more optimal dispatch as decisions are made while taking into consideration system conditions ahead of time. In standard simulations, a 6- hour look-ahead is applied. This allows the dispatch decisions for one day, for example, to account for the demand/generation/interconnection conditions of the first 6 hours of the following day to be account for. This ability is particularly beneficial for the optimal operation of storage technologies where energy is stored today and used in the future. This aspect is discussed again in Chapter 6 where I use a different approach to replicate a look-ahead period equating to 3 years.

4.3.1.1 Scenario description

The installed power generation capacities for the EU-28 Member States were outlined in the European Commission's Reference Scenario by generation class, for example; Hydro, Oil, Gas, Solids, Biomass/Waste, et cetera. The portfolios were disaggregated into individual power plant types by fuel class and assigned standard technical characteristics as shown in Table 4.1 and Table 4.2 an approach used previously by Deane et al. (2015b). Assumptions based on ENTSO-E (2015) Ten Year Network Development Plan – Vision 1[9] publication were used to represent the Swiss and Norwegian power systems.

Table 4.1: The standardised generation characteristics applied.

Fuel Type	Capacity (MW)	Start Cost (€/MW)	Min Stable Factor (%)
Biomass/waste	300	33.3	30
Derived gas	150	80	40
Geothermal heat	70	42.9	40
Hydro (lakes)	150	0	0
Hydro (run of river)	200	0	0
Natural gas CCGT	450	177.8	40
Natural gas OCGT	100	100	20
Nuclear	1200	100	60
Oil	400	187.5	40
Solids	300	266.7	30

Table 4.2: Fuel and carbon price assumptions

Fuel Type / Carbon	2030
Oil (€2010 per boe)	€90
Gas (€2010 per boe)	€52
Coal (€2010 per boe)	€18
Carbon - ETS (€2010 per Tonne)	€40

The model is simulated as a closed loop comprising of 30 European countries and 58 interconnectors and overall regional generation must meet regional load in each hour simulated. Therefore, when all hourly interconnector flows (exports and imports) are summed, the result (net of interconnector transfer losses) must be zero, as shown in Eq. (1).

[9] Vision 1 was chosen over the other scenarios represented as it was the most conservative 2030 option and, therefore, most closely aligned with the European Commission's Reference Scenario.

$$0 = \sum_{i=1}^{58}(IC_i) \qquad (1)$$

where i represents interconnectors and IC is the flow of electricity on an interconnector. IC flow is positive for exports and negative for imports.

Demand profiles: Hourly resolution demand curves were attained from historic ENTSO-E data (ENTSO-E, 2012) and linearly scaled to the overall demand estimates outlined in the European Commission's Reference Scenario.

Wind, solar and hydro profiles: Hourly generation profiles for wind power were sourced from Gonzalez-Aparicio et al. (2016). Solar profiles were created from NREL's PVWatts® calculator which estimated the solar radiance from assumptions around system location and basic system design parameters for each country (Dobos, 2013). Hydro profiles are decomposed from monthly generation constraints provided by ENTSO-E (2012) to weekly and hourly profiles in the optimisation algorithm function in PLEXOS®.

Pumped hydro energy storage is not simulated in this model for the reason being that it increases simulation time significantly but more importantly because under Article 5(3) of the Renewable Energy Directive *"renewable energy sources shall be calculated as the quantity of electricity produced in a Member State from renewable energy sources, excluding the production of electricity in pumped storage units from water that has previously been pumped uphill."* (European Commission, 2009a, p.29).

Interconnection: The interconnection capacities between countries represented in the model are based on projections from the ENTSO-E (2015) *'Ten Year Network Development Plan 2016'* publication, see Figure 4.1.[10] Interconnection is limited to net transfers between countries and excludes interregional transfers in line with the EU day-ahead market schedule dispatch clearing algorithm, EUPHEMIA. Given that interconnection losses were included in the electricity demand profiles used already they were not represented as losses in the dispatch again but to account for their costs in terms of the economic dispatch, wheeling charges of €4/MWh were applied to the model for all interconnection lines.

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[10] Malta is the only electrically isolated country represented in the model.

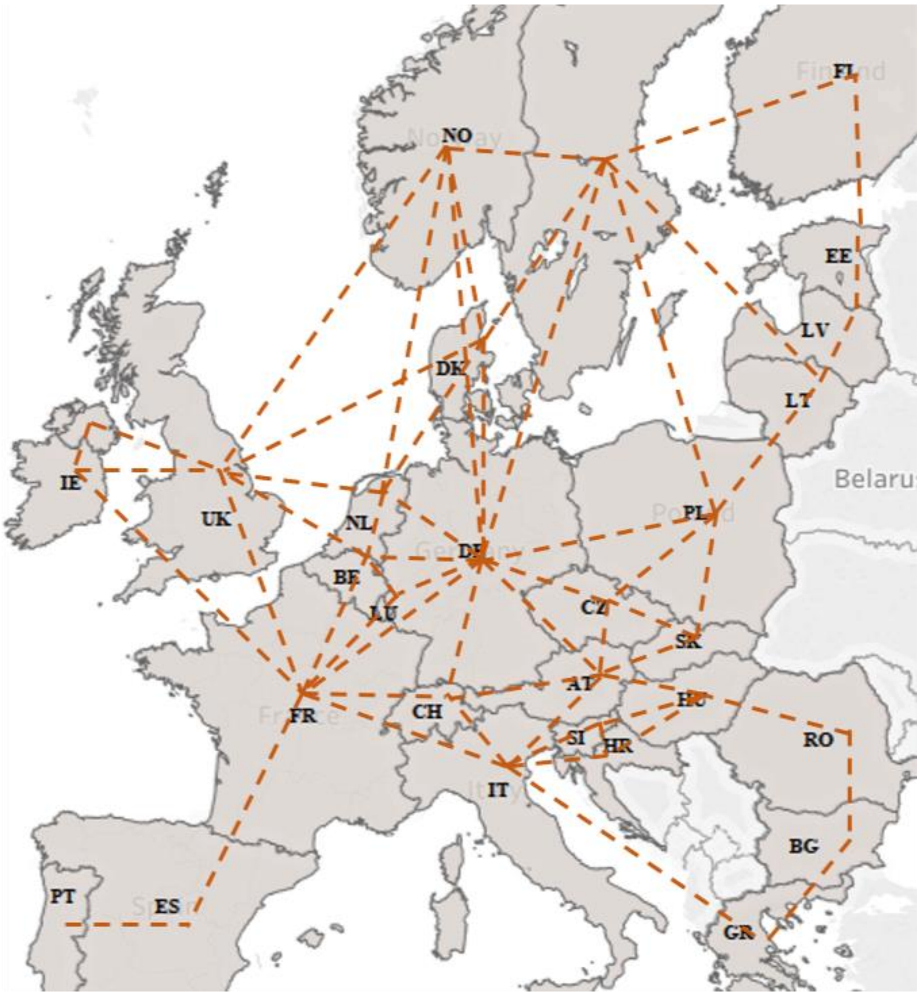

Figure 4.1: High-level view of interconnection capacity represented in the PLEXOS® model. Greece is also electrically connected to Cyprus. This interconnector is excluded from Figure 4.1 to maintain granularity around highest interconnection density areas.

4.3.2 Post-processing

Post-processing is required to identify the RES-E flow across Europe's interconnectors for each hour of a given year. Due to the complexity associated with tracing wheeled exports to their source(s), this approach employs an iterative process to continually improve calculation accuracy until all RES-E transfer is accounted for. The foundation of this approach lies with the identification of the true source(s) of wheeled exports in each hour. Once known, the exported electricity is checked for any RES-E content. While in most cases no RES-E exist, when it does however, it is possible to trace the energy to its point of consumption purely based on the economic dispatch of generation portfolios and the merit-order approach (Sáenz de Miera et al., 2008; Sensfuß et al., 2008).

This approach functions on the assumption that all country-specific electricity markets within the model employ an economic dispatch approach, therefore RES-E is consumed locally to meet domestic load before any renewable exports can occur. This is supported by the requirement under Article 16 of Renewable Energy Directive for transmission system operators to comply with their duty to minimise curtailment of renewable electricity and based on the knowledge that a high share of EU RES-E generation receive power purchase agreements through government backed support schemes, as demonstrated by RES Legal (2017). Therefore RES-E can bid in low, zero or negative bid prices to the energy market to reduce dispatch exposure.[11] Furthermore, when RES-E flow has been identified as travelling between countries the same principal is used in the importing country in terms of economic dispatch. In other words, RES-E is only exported if the combined domestic RES-E and imported RES-E (if applicable) exceeds domestic load.

4.3.2.1 Components of interconnector flow

In this methodological approach, electricity transferred via interconnection is considered a combination of two components. The electricity is either a direct product of the country where the interconnector originates or an indirect product which is derived from another location and passes through one country to another, also referred to as 'wheeling electricity'. Henceforth the first is referred to as "Domestic Exports," the second "Wheeled Exports." Domestic Exports (DE) occur when domestic generation exceeds domestic load, causing an export of electricity directly associated with the country in question. Wheeled Exports (WE) are equal to interconnector flow net of Domestic Exports, see Eq. (2).

$$IC_i = \sum_{i=1}^{58}(DE_i + WE_i) \qquad (2)$$

where,

- DE = Domestic Generation – Domestic Load
- WE = Interconnector Flow – Domestic Exports (if Domestic Exports >0)

else,

[11] RES-E generation has the advantage of priority dispatch under the Renewable Energy Directive (2009/28/EC). This may not be in the case in 2030 as outlined in the draft directive on the Internal Electricity Market. (European Commission, 2016d)

- WE = Interconnector Flow

where *i* represents interconnectors.

4.3.2.2 Calculating the RES-E share of interconnector flows

To measure the RES-E share of Wheeled Exports across an interconnector, the true source of the electricity must first be determined by tracing interconnection flows back to their origin. In doing so, what is actually identified as the source of Wheeled Exports is the Domestic Exports of a country that is not importing electricity. Therefore, to identify the source(s) of wheeled electricity in a given hour a country must export electricity and not import, as shown in Eq. (3). The RES-E share of electricity transfer is then assessed and if applicable, quantified using Eq. (4). Eq. (4) states that RES-E generation *must* first exceed domestic load for any renewable export to occur. If RES-E export occurs, it is demonstrated as a percentage of domestic exports as shown in Eq. (4). The percentage of RES-E flow in these domestic exports is assumed to be uniform across all exporting lines. Finally, the results are tabulated to determine the RES-E volume *imported* into each country in a given hour, thereby concluding **Step 1** in what is an iterative process to ascertain the RES-E share of all interconnector flows.

$$True = \sum_{j=1}^{n_j}(Exp_j) > 0 \ \& \sum_{j=1}^{n_j}(Imp_j) = 0 \qquad (3)$$

$$RES\_\%_{n_j} = \left(\frac{RES\ Gen_j - Dom\ Load_j}{Exp_j}\right) \qquad (4)$$

where,

- $RES\ Gen_j$ - $Dom\ Load_j > 0$

where *j* represents the country and n_j is the total number of interconnections to country *j*. Exp_j and Imp_j represents electricity exports and imports respectively from country *j*. $RES\_\%_{n_j}$ is the renewable share of exports from country *j* across its total number of interconnections n_j. $RES\ Gen_j$ and $Dom\ Load_j$ represent renewable generation and domestic load respectively in country *j*.

Figure 4.2 and the following explanation describes how each step in the post-processing phase relates to the next in terms of accounting for RES-E transfer across interconnector capacity. In **Step 1** the figure shows Country A as the only country to successfully meet the requirements outlined in Eq. (3) and Eq. (4). In other words, Country A is only country that is both 1) exporting and not importing power, and 2) has total renewable electricity generation that exceeds its domestic consumption in the period considered. Thus, it has domestic exports. The renewable share of these domestic exports is determined as the proportion of renewable energy that is excess to demand divided by the total export on all country's interconnector lines. It has no wheeled exports because it is not importing on any of its interconnection lines which means that its total exports must equal its excess domestic generation. As such, interconnector flow between countries 'A – B' and 'A – S' are represented by *green* unbroken lines to signify RES-E flow in a given hour. The main objective of **Step 1** is to identify the sources of wheeled exports in each hour and assess what level of renewable energy is present, if any. The following steps use this information as a foundation to trace the RES-E flows to their final location through multiple iterations.

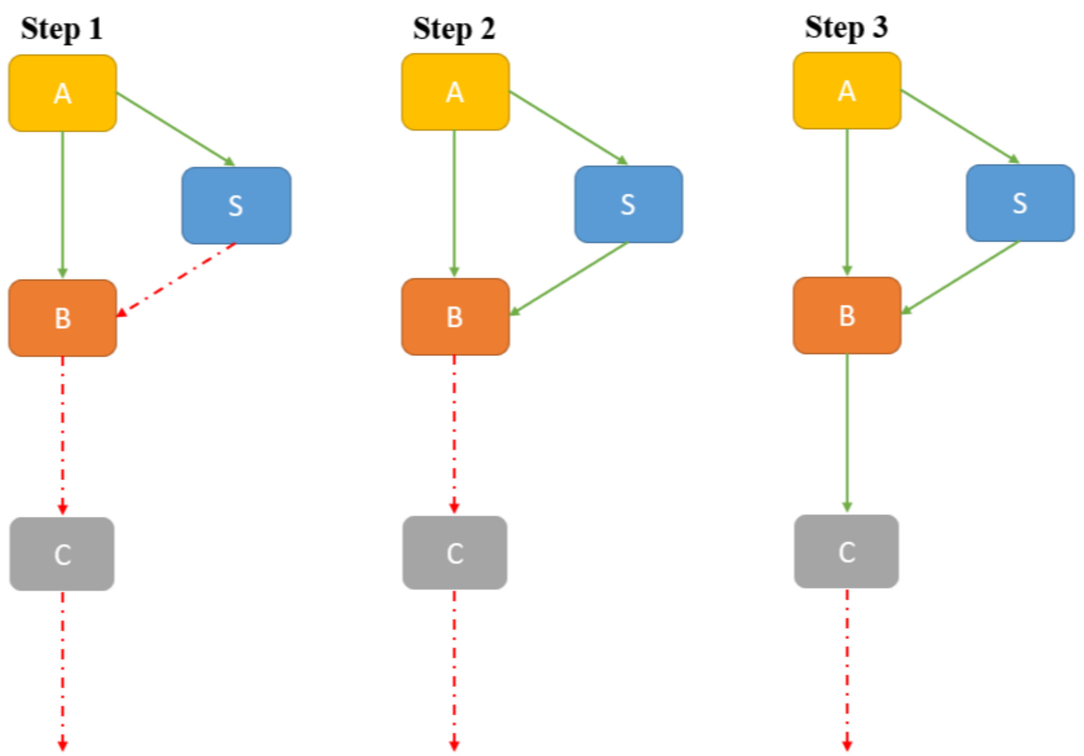

Figure 4.2: Illustrative example to explain the different steps undertaken.

Step 2 sums the imported RES-E (from the sources as identified in the previous step) and the domestic RES-E in the country of focus to determine if renewable exports occur in a given hour. This calculation must abide by the condition that RES-E generation fulfils domestic load before renewable exports are possible. If under these conditions there are RES-E exports, the percentage RES-E flows on interconnector lines are then calculated for the period in accordance to Eq. (5).

$$RES\_\%_{n_j} = (\frac{RES\ Gen_j + RES\ Imp_j - Dom\ Load_j}{Exp_j}) \qquad (5)$$

where,

- $RES\ Gen_j + RES\ Imp_j - Dom\ Load_j > 0$

where $RES\_\%_{n_j}$ is the renewable share of exports from country *j* across its total number of interconnections n_j. *RES Gen$_j$*, *RES Imp$_j$* and *Dom Load$_j$* represent renewable generation, renewable imports and domestic load respectively in country *j*.

To best illustrate Step 2 the central position of Figure 4.2 was developed. In this position, the transfer between countries 'B – C' and 'S – B' are recalculated to identify if the flows contain RES-E. The figure shows the interconnection between 'B – C' in this step as a red broken line to indicate that no RES-E flow, therefore the combination of imported and domestic RES-E does not exceed domestic load in Country B.

However, the RES-E flow between 'B – C' has not yet fully accounted for all RES-E flow up-stream. In Step 1, the interconnector from 'S – B' had no RES-E flow as imports from Country A were not yet accounted for in Country S. In Step 2, this RES-E flow is accounted for and the interconnection between S – B is green – meaning the combination of imported and domestic RES-E exceeds domestic load and RES-E is exported. However, the interconnector 'B – C' has not yet taken account of this additional RES-E flow wheeled through Country S. This imprecision is corrected in Step 3 when the RES-E flow becomes fully accounted for across the interconnection 'B – C'. As a result, the interconnection changes to a green unbroken line which indicates RES-E flow - meaning that the combination of imported and domestic RES-E exceeds domestic load in Country B. For this reason, this methodological approach employs an iterative approach to account for the numerous interconnector flows that occur in a meshed grid, such as the European electricity system represented in this chapter by 58 interconnectors and 30 countries.

Step 3-6: Steps 3-6 are identical to Step 2, with each using the table from the previous step to identify the RES-E volume of imported electricity, i.e. increasing accuracy with each step. This methodology uses as many steps as necessary to account for all RES-E flows. While comparing Step 5 to Step 6, the results for all 58 interconnectors across Europe over the year were identical, therefore Step 5 was the final iteration.[12] These values account for renewable electricity flows all the way back to their source and provide an insight into the locations where RES-E is consumed on an hourly basis for the year 2030.

4.4 Results

4.4.1 Wholesale electricity prices

Figure 4.3 demonstrates wholesale price differentials with 26 countries inside ±10% of the €73.21 per MWh average. Low price differentials are observed due to the increased level of interconnection capacity expected in 2030. The Czech Republic has the highest wholesale price of any electrically interconnected country simulated, it also experiences the highest level of interconnector congestion (55%) over the year. This congestion is caused by physical transmission capacity constraints and directly contributes to price formation as lower cost electricity from surrounding countries cannot be imported at a sufficient rate to further suppress the marginal price.

[12] The number of steps may change depending on a number of variables, such as installed renewable generation capacity, interconnection capacities, domestic load, generation and load profiles, et cetera.

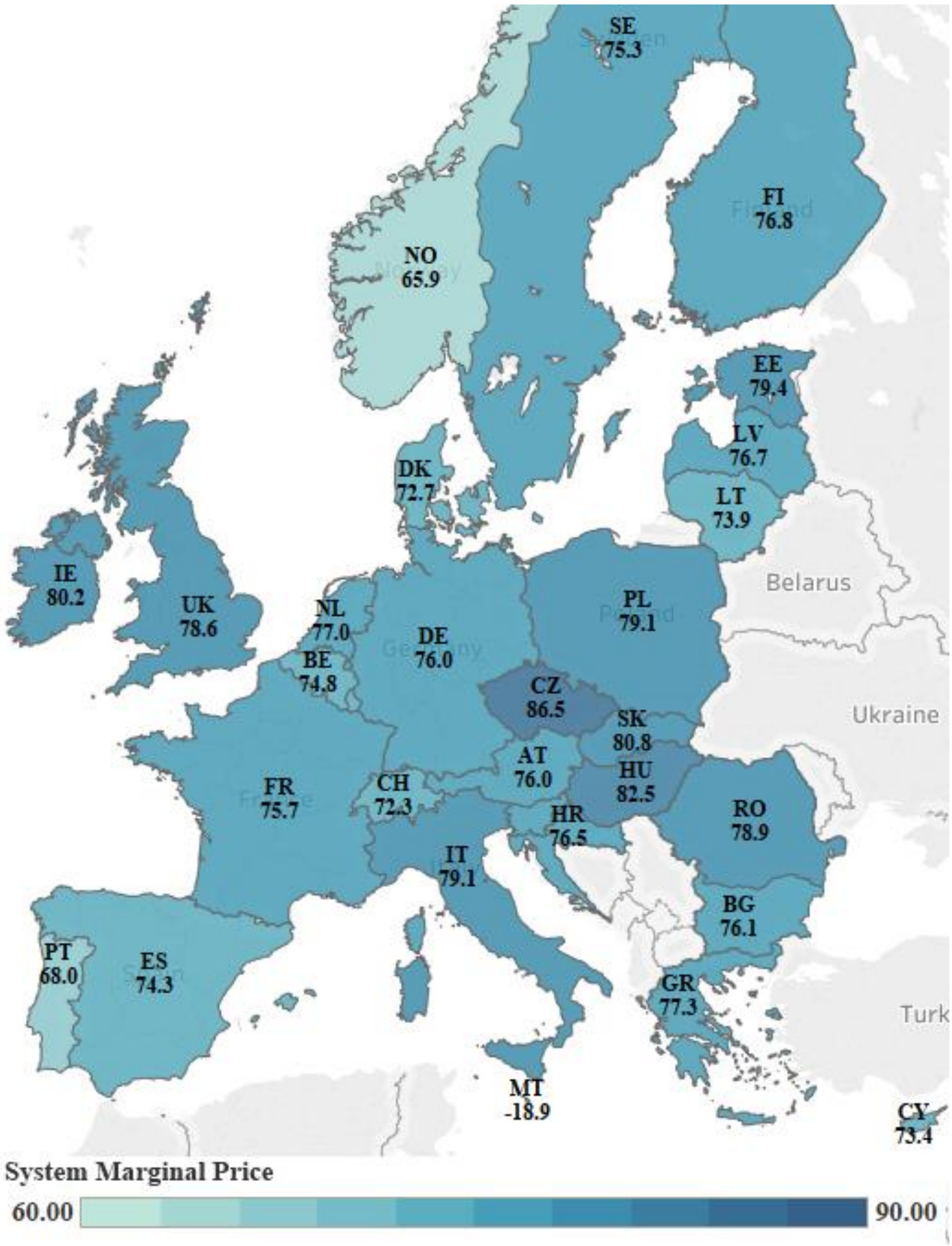

Figure 4.3: Wholesale electricity prices of the EU-28 and two non-EU countries; Norway and Switzerland. Due to the aggregated nature of the generation portfolio, Malta experiences a non-optimal dispatch which results in numerous hours of negative pricing.

4.4.2 RES-E interconnector flow

The methodology outlined in Section 4.3.2 is applied to identify and also quantify the RES-E contribution of electricity transfer between countries on a high temporal resolution. Figure 4.4, Figure 4.5 and Figure 4.6 show three insights to the findings from the post-processing phase.

The figures outline the overall electricity flow and renewable electricity flow between countries along with the renewable share of the transferred electricity on an annualised basis.

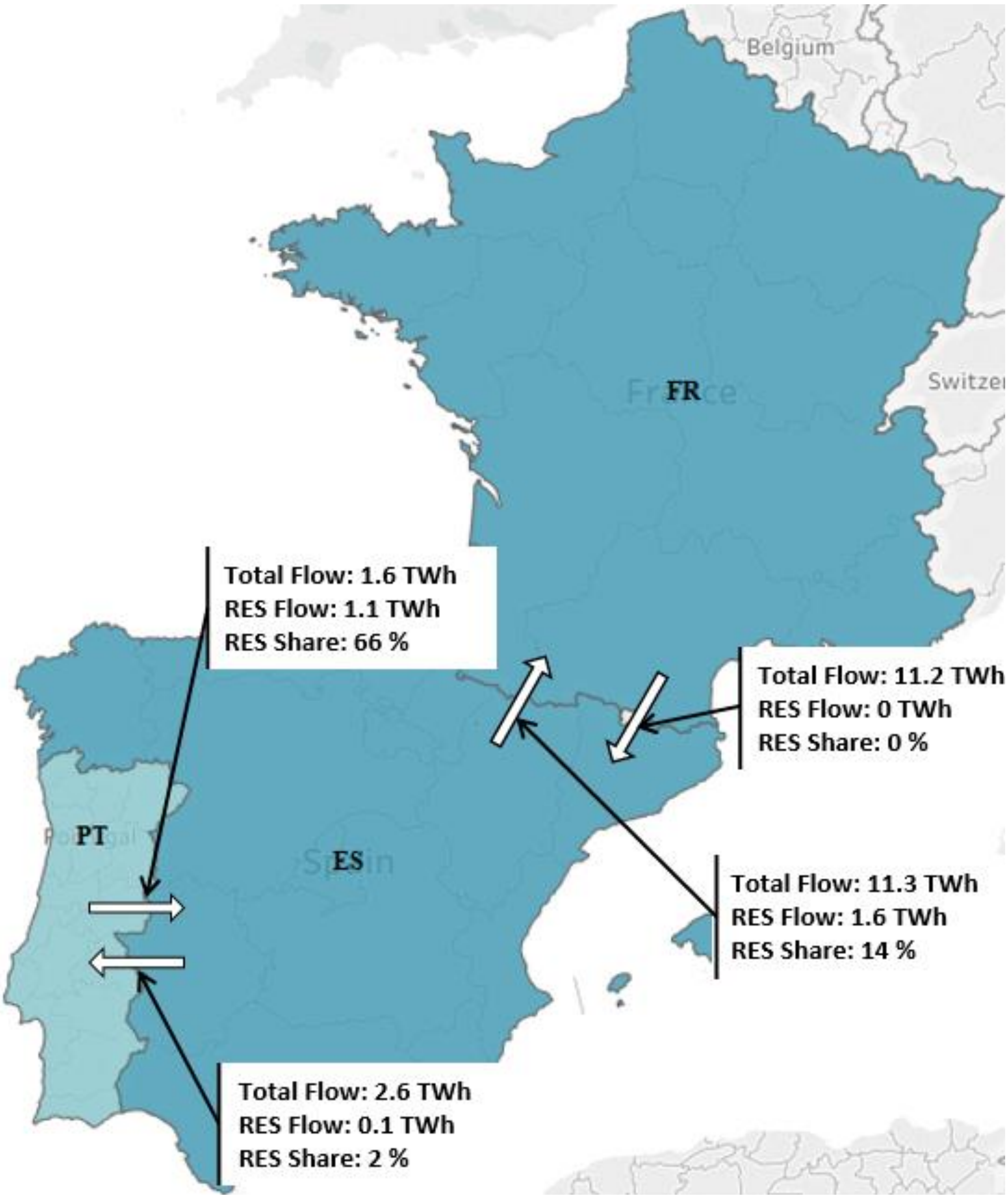

Figure 4.4: Interconnection activity between Portugal, Spain and France

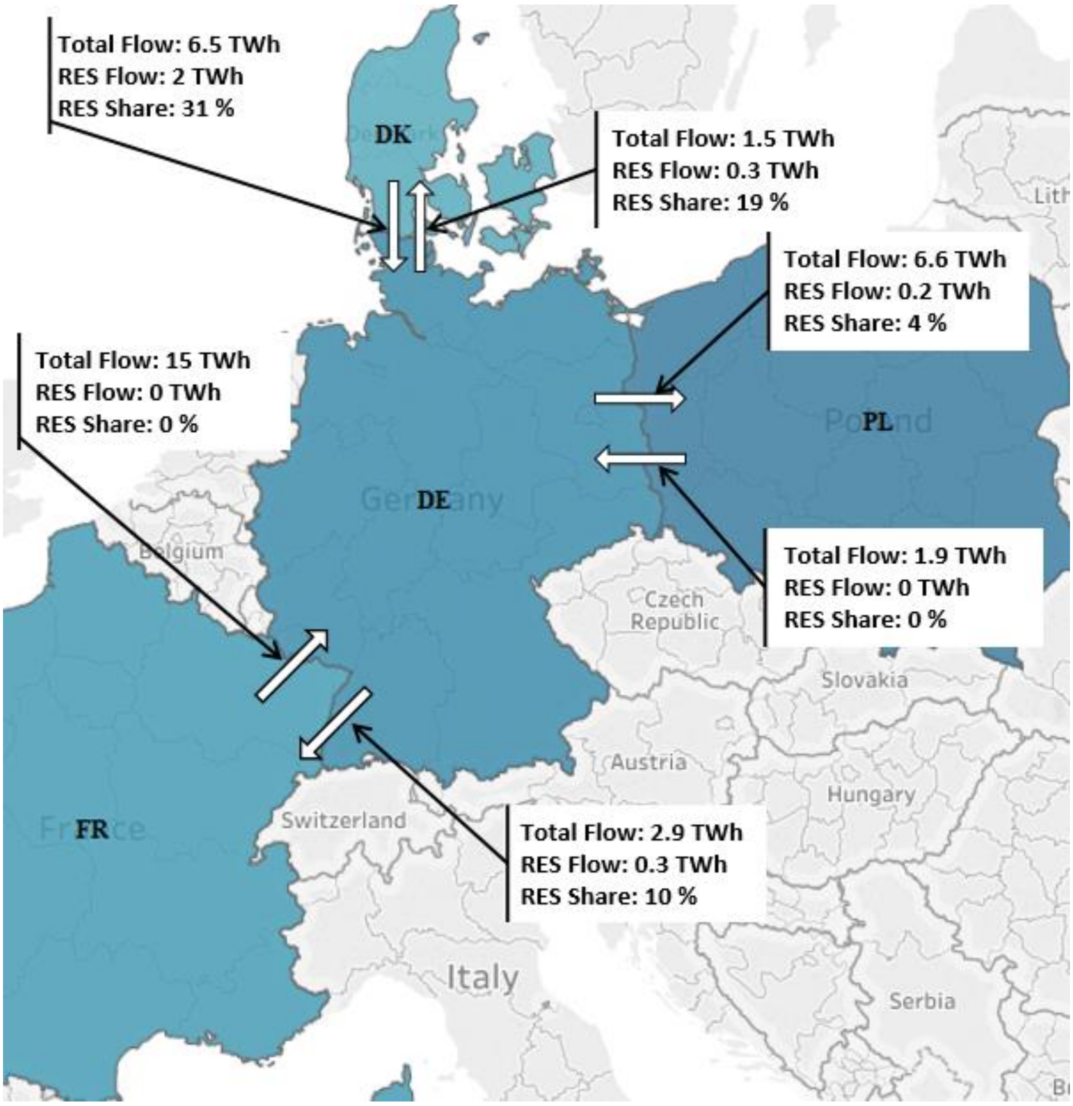

Figure 4.5: Interconnection activity between France, Germany, Denmark and Poland

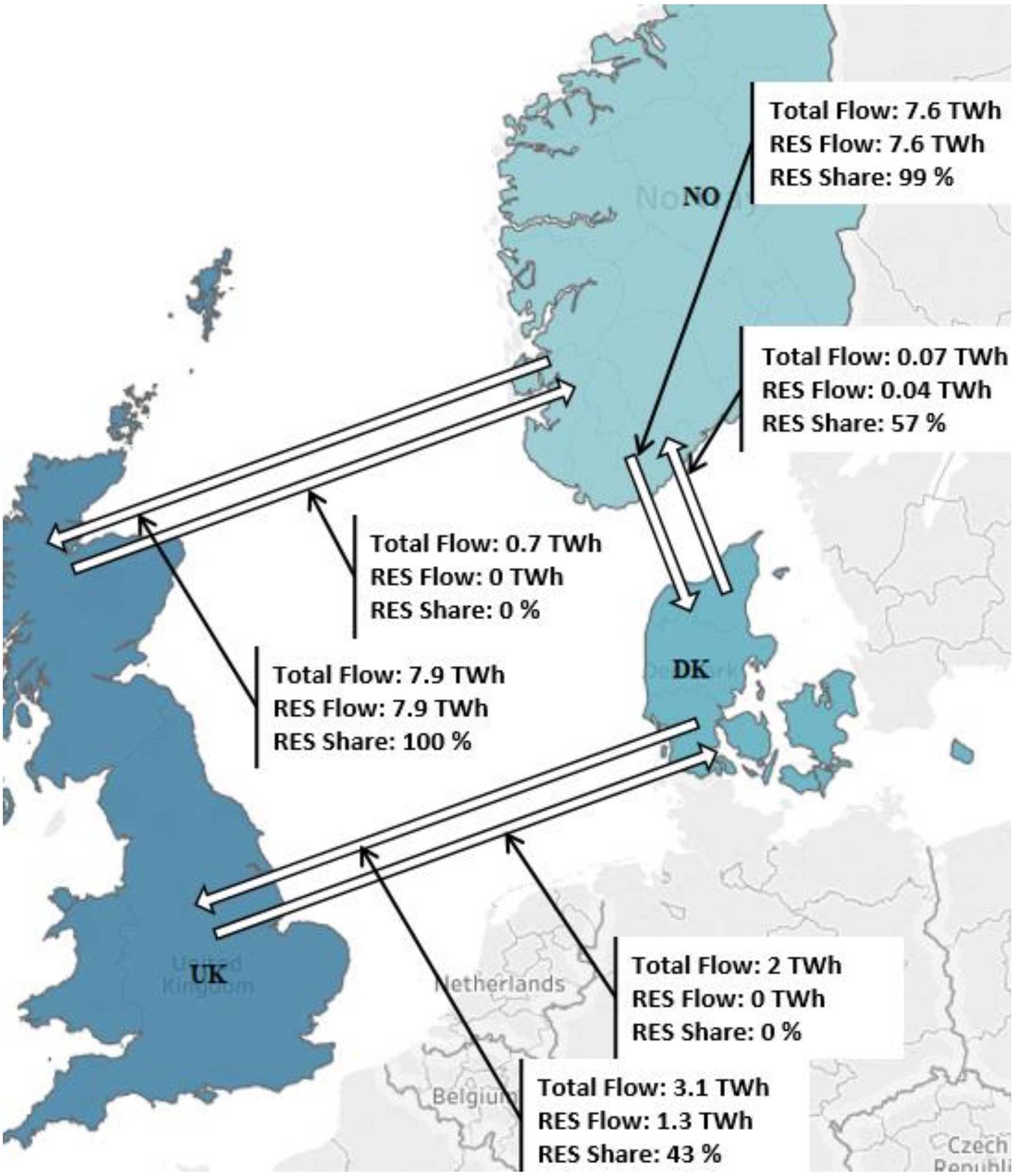

Figure 4.6: Interconnection activity between Norway, Denmark and the United Kingdom

Figure 4.4, Figure 4.5 and Figure 4.6 highlight the unequal electricity transfer between a selection of countries over a year. The figures also demonstrate the difference in RES-E share that is transferred over the same period. However, it should be reiterated that both observations are contingent on assumptions surrounding generation portfolios and profiles used, demand curves, fuel costs, taxes, et cetera. Figure 4.4 shows Portugal and Spain transferring a similar amount of total electricity back and forth over the year, yet 66% of exported electricity originating in Portugal is from renewable sources while only 2% of electricity returned is considered renewable. Similarly, France exports high volumes of electricity to Spain but with no RES-E share, which is directly associated with its generation portfolio, i.e. high share of nuclear power. This can also be seen in Figure 4.5 where France is a net exporter to Germany but, again, with no RES-E share. Figure 4.5 further highlights the issue regarding RES-E share of imports-exports when analysing the interconnections between Germany-Denmark and Germany-Poland where large differences between RES-E contributions are identified. Figure 4.6 is perhaps the most striking example to show the significance, where hydro based Norwegian power is exported to the Denmark and UK at 99% and 100% RES-E over the year respectively. While Norway does not import significant quantities of electricity in the simulation, the volume that is imported has a much lower RES-E content. Table 4.3 demonstrates the net RES-E share transferred on each interconnector. Remaining cognisant of the conservative assumptions surrounding scenario selection, the analysis carried out as part of this chapter estimates that 60 TWh of renewable electricity is transferred across European interconnectors in 2030 or 19% of total cross-border flow.

Table 4.3: Net renewable electricity flow transfer as a share of total electricity transfer. The table contains the electricity flows to and from the all island (AI) electricity system which consists of Ireland and Northern Ireland, along with Great Britain (GB).

AI-GB	**AT-CZ**	**AT-DE**	**AT-HU**	**AT-IT**	**AT-SI**	**BE-DE**	**BE-FR**	**BE-GB**	**BE-LU**
46%	15%	12%	23%	25%	25%	-10%	0%	0%	-9%
BE-NL	**BG-GR**	**BG-RO**	**CH-AT**	**CH-DE**	**CH-FR**	**CH-IT**	**CY-GR**	**CZ-DE**	**CZ-PL**
-1%	-13%	0%	-6%	6%	19%	24%	2%	-2%	0%
CZ-SK	**DE-DK**	**DE-FR**	**DE-LU**	**DE-NL**	**DE-PL**	**DE-SE**	**DK-GB**	**DK-NL**	**DK-NO**
0%	-12%	10%	6%	10%	4%	9%	43%	37%	-42%
DK-SE	**EE-FI**	**EE-LV**	**ES-PT**	**FI-SE**	**FR-AI**	**FR-ES**	**FR-GB**	**FR-IT**	**FR-LU**
34%	0%	-4%	-64%	0%	-18%	-14%	0%	-1%	0%
GR-IT	**HU-HR**	**HU-RO**	**HU-SI**	**HU-SK**	**IT-SI**	**LT-LV**	**LT-PL**	**LT-SE**	**NL-GB**
20%	-1%	-1%	-1%	0%	-1%	-3%	0%	-1%	1%
NO-DE	**NO-GB**	**NO-NL**	**NO-SE**	**PL-SE**	**PL-SK**	**SI-HR**			
79%	100%	98%	94%	0%	0%	0%			

4.4.3 Country-specific renewable electricity shares

Viewing renewable electricity in this alternative light opens ‘Pandora’s box’ in terms of accounting for the renewable electricity shares of each country. Identifying where renewable electricity is produced, transferred to and finally, where it is consumed in high temporal resolution is an accurate means of assessing the share of the electricity sourced from renewable sources that is *actually* consumed within state. Figure 4.7 compares RES-E shares of individual countries applying the current approach long used by the European Commission (RES-E production) to the alternative approach outlined in this chapter that accounts for renewable electricity transfer across interconnectors (RES-E consumption).

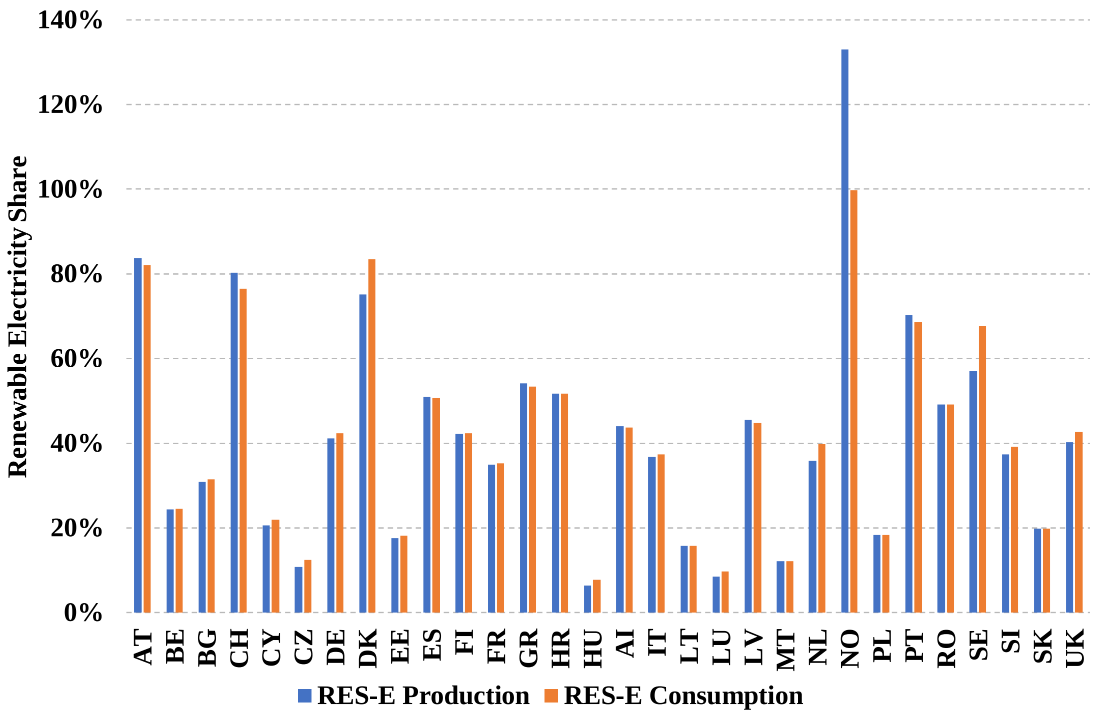

Figure 4.7: Comparing the RES-E share of 30 countries applying the traditional approach (RES-E production) and an alternative methodology proposed in this chapter (RES-E consumption). The simulation did not model generator "own use" or transmission and distribution losses, therefore Gross Final Consumption is unknown. In its place, the final electricity consumption is used to measure RES shares. For example, the RES-E Production is calculated using the renewable generation divided by the final electricity consumption of each country. RES-E Consumption uses the renewable generation plus renewable imports minus renewable export divided by final electricity consumption. It is recognised that this assumption is not aligned with the Renewable Energy Directive's methodology, however it provides an insight into the relative difference between the two approach which is the main point of the figure.

Using the approach outlined in this chapter, Figure 4.7 shows a higher number of countries with a different level of renewable electricity than what would otherwise be reported using the current production-based approach. When wind generation is high in the Nordics and hydro-power capacity in Norway is generating low-cost electricity, excess generation is exported out of the Nordic region. While this electricity may be used elsewhere, it is still from a renewable energy source. The same applies when solar capacity in the more southern, warmer parts of Europe is producing high levels of power and this is transferred to load centres across the wider region, and so on. Applying the current approach used by the European Commission, while a simpler approach, does not account for this transfer.[13] For example, Figure 4.7 demonstrates

[13] The authors recognise that 'Statistical Transfers' are allowed under the Renewable Energy Directive (2009/28/EC), however this option is yet to be availed of by any Member State, at time of writing.

that, when taken on an annualised basis, Norway has excess renewable electricity which is transferred to surrounding countries to meet their demand (if the correct price signals are in place.)[14] The traditional approach to quantifying RES-E does not capture this transfer or where RES-E is consumed and therefore could be seen as a poorer approach in calculating RES-E for adjoining countries. Denmark and Sweden are examples that show the inability of the traditional approach to account for the level of renewable energy *actually* consumed within state – which in both cases is higher than otherwise would be reported, as shown in Figure 4.7.

For simplicity, measuring RES-E production is an easier option. However, as electricity markets across Europe become more intrinsically linked and transition toward a complete EU-wide internal market, the current approach may no longer be the correct strategy to capture where RES-E is consumed and importantly where it is paid for. In Section 4.5 the case study results demonstrated thus far are expanded upon to discuss issues around cross-border subsidisation, price distortion and cost inequality.

4.5 Discussion

Section 4.4 results demonstrate the difference between a consumption and production-based approach to quantifying RES-E in Europe. This section examines several considerations and impacts associated with the findings and discusses the possible consequences.

4.5.1 What does a consumption-based approach offer?

A consumption-based approach improves clarity, accuracy and awareness of where RES-E is produced and it is consumed. The clarity of knowing where electricity is generated, how interconnector flows are determined and the effects of generation portfolios in neighbouring countries. Improved accuracy through the accounting of imported renewable electricity generated outside of state boundaries yet consumed within, and the awareness of potential issues that can arise when the volume and scale of RES-E transfers across the region escalate.

[14] This assumption is supported by evidence available from Eurostat (2016) showing Norway producing 138 TWh of RES-E in 2015 to meet a GFC demand of 129 TWh.

A consumption-based approach also sheds light on issues of price distortion (caused by uncoordinated support schemes) and cross-border subsidisation (creating cost inequality).

4.5.2 Who pays the 'true' cost of transferred renewable electricity?

The EU Target Model is designed to promote the free flow of electricity throughout Europe unaffected by network constraints or price distortions to achieve a price convergence across the region. While Figure 4.3 shows the effects of this framework in terms of a relatively shallow price range, Figure 4.4, Figure 4.5 and Figure 4.6 reveal a different perspective on unconstrained electricity flow regarding renewable electricity transfer. Acknowledging that significant volumes of RES-E capacity across Europe are supported outside of the energy market through support mechanisms, and yet interconnector flows are based on wholesale energy market prices, this creates a paradox. As more RES-E capacity is installed, wholesale electricity prices reduce further due to the merit order effect, becoming more attractive to export at a price that is *not* truly reflective of the cost to generate the power being exported. Thereby leaving the country where the renewable electricity is produced to meet the stipulations of the support schemes in place, i.e. remunerate the RES-E capacity to the agreed terms and conditions while the energy is consumed outside of state borders.

For instance, the simulation shows that the interconnection capacity from Denmark to Sweden exports (imports) approximately 1.8 (1.6) TWh over the year. When Denmark exports to Sweden the electricity is 35% RES-E compared to 0.4% when flows reverse, as can be seen from Table 4.3. Coupled with the examples shown in Figure 4.4, Figure 4.5 and Figure 4.6, this demonstrates that countries such as Denmark, Portugal, Norway and Germany for example are exposed to cost inequalities if 1) electricity is traded on interconnectors using its wholesale price (which it is and will continue to do so in line with the EU Target Model) and 2) RES-E capacity is supported outside of the energy market (which is currently the case in most European countries). This longstanding concern around price distortion effects caused by pecuniary externalities is a well published topic, see (Buchan and Keay, 2016; Couture and Gagnon, 2010; Fouquet and Johansson, 2008; Glachant and Ruester, 2014; Gore et al., 2016; International Energy Agency, 2016a; Joskow, 2008a; Lehmann and Gawel, 2013; Meyer and Gore, 2015; Roques, 2008). Nevertheless, with large volumes of RES-E capacity required to achieve the future goal of a decarbonised power sector, this challenge may be amplified and become a more widespread problem noting that this chapter demonstrates a conservative view of what may actually unfold in 2030 (Capros et al., 2016).

Quantifying the financial implications for countries net-exporting RES-E is a challenging task as there has been little coordination between Member States when setting up RES-E support schemes across Europe over the years.[15] Neighbouring countries may endure dissimilar levels of price distortion due to the differing support structures, remuneration levels and/or contract lengths. Bearing in mind the current Member State specific RES-E targets for 2020, in simple terms this means if a country could not achieve the necessary uptake in RES-E capacity to meet national targets, the remuneration offered or scheme framework may be altered to increase its attractiveness through higher remuneration, longer contracts, or less risk-exposure. Ireland for example, changed its RES-E support in 2007 from a competitive bidding process to a centrally administered price setting scheme to increase profitability for RES-E generation capacity. According to Global Wind Energy Council & International Renewable Energy Agency (2013), many projects awarded financial support through the competitive bidding process in Ireland had not been built due to "*low bidding prices and lack of profitability*" (p.100).[16] In a similar vein to price distortions stemming from uncoordinated capacity mechanisms as discussed by Gaffney et al. (2019b); Glachant and Ruester (2014); Gore et al. (2016); Meyer and Gore (2015), uncoordinated RES-E support schemes may be viewed in the same light during the transition to a future regional market based on undistorted price signals. However, equally as important is the need to implement a framework for remunerating renewable electricity transferred across boundaries that improves cost equality – paying the 'true' cost rather than market price.

4.5.2.1 How to address price distortion

Viewing these concerns in the correct context is essential; meaning that the issue is borne out of a requirement for cross-boundary interactions, therefore the solution must also be viewed in the same geographical context. Introducing a coordinated approach to RES-E support schemes

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[15] While it must be recognised that the European Commission has used its "autonomous control power" regarding the policing of national state aids to shape support schemes in some way, as alluded to by Buchan and Keay (2016) and also having recently introduced a working document on guidance for the design of renewable support schemes (European Commission, 2013), it is recognised that support sharing and full coordination has not yet been achieved to date.

[16] For more information on the development of wind power in Ireland and the entire Irish electricity system between 1916-2015, see (Gaffney et al., 2017)

through a European agency could provide the solidarity needed for cost equality to thrive, and thereby maximising societal welfare for all European electricity consumers. An agency appointed to administer the renewable electricity affairs of the region that takes cognisance of individual economic, societal, technical and environmental conditions to create a level playing field, free of price distortion created by differing support structures. This may not be an excessively unrealistic proposal, instead it could be recognised as a new, or an expansion of an existing, department within the Agency for the Cooperation of Energy Regulators (ACER) for example. An agency which was created through the EU Third Energy Legislative Package (2009/72/EC) to ensure the smooth functioning of the internal energy market (European Commission, 2009b).[17]

The chosen agency could also be responsible for accurately quantifying renewable electricity shares and remunerating producers from the country that consumed their electricity instead of where it has been produced – effectively socialising the cost of renewable electricity across state boundaries to improve cost equality during Europe's transition to a decarbonised system. This approach could be seen as a reform or even an evolution of the 'statistical transfers' permitted between Member States in Article 6 of the Renewable Energy Directive and Article 8 of the latest Renewable Energy Directive draft (European Commission, 2016c).

Increasing the accuracy of cost distributions associated with the consumption of renewable electricity may also provide secondary gains. Aside from reducing the level of revenue required to remunerate RES-E generation in an exporting country, this approach may lower the economic barriers surrounding the cost to consumers of developing higher levels of RES-E capacity. If, for example, a country has the correct topography and climate for hydro-powered generation, then the cost as well as the benefit of this renewable energy source can be shared with neighbouring nations. This may encourage further development in countries rich in potential renewable assets such as geothermal, solar, biomass, biogas, wave, tidal and wind energy by lowering the economic barriers which often add weight to institutional and organisational barriers as shown in publications by Byrnes et al. (2013); Foxon et al. (2005);

[17] This may be a timely suggestion as there is currently a proposal to strengthen ACER's powers and responsibilities included in the draft directive on the Internal Electricity Market (European Commission, 2016d)

Hvelplund et al. (2017); Lund et al. (2014); Lund and Quinlan (2014); Painuly (2001); Reddy and Painuly (2004); Scarpa and Willis (2010); Verbruggen et al. (2010).

4.5.2.2 Is there appetite for change?

Buchan and Keay (2016) highlight that the European Commission *"has twice tried, and twice failed, to persuade EU governments to adopt a harmonised EU-wide subsidy system."* (p.7). Therefore, an appetite appears to exist at EU level. Furthermore, Article 5 of the latest Renewable Energy Directive draft the European Commission includes plans to open access for RES-E support schemes to installations located in other Member States (European Commission, 2016c). However, legal conflicts such as the *PreussenElekra* case of 2001,[18] or more recently the *Ålands Vindkraft* case in 2014,[19] highlight the individual nature of EU Member States and the 'parochial' thinking that exists regarding environmental targets – albeit the very nature of individual targets encourages this behaviour.

The issue is perhaps best epitomised by the Ålands Vindkraft case, where a windfarm situated in the Åland archipelago of Finland applied for a Swedish RES-E support scheme as it was directly connected to the Swedish system but not that of Finland. The application was rejected on the grounds that it was unfair for Swedish consumers to remunerate a wind farm contributing to Finland's RES target. Once this occurred, the boundaries of environmental protection were clearly drawn by Sweden, even in the face of breaching European energy market law surrounding the free movement of goods, i.e. electricity. While the European Court of Justice required justification from Sweden regarding the case, the ruling was in Sweden's favour as the argument was successfully made that the Renewable Energy Directive *does* permit the trans-boundary RES-E support schemes but *does not* require it (European Commission, 2009a). Therefore, Sweden were found to have acted within the boundaries of EU law.

Despite the European Court of Justice ruling, Durand and Keay (2014) believe that the Ålands Vindkraft case raises more questions than it answers regarding the relationship between environmental protection (and individual Member State targets) and its place within the

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[18] For more information, see: http://curia.europa.eu/juris/liste.jsf?language=en&num=C-379/98

[19] For more information, see: http://curia.europa.eu/juris/liste.jsf?num=C-573/12

European energy market law. Durand and Keay (2014) highlight that other Member States have cited the Ålands Vindkraft case as a justification for discriminatory practices. Germany for example, cited the case while attempting to introduce a surcharge on imported electricity through a new renewable energy law that would be used to finance domestic RES-E producers.[20]

While it is the opinion of Buchan and Keay (2016) that cross-border subsidy sharing may be a bridge too far at the time of publication, it must be seen as progressive that Norway and Sweden introduced a joint support scheme that includes an international agreement between the countries to recognised 'green energy' produced in another jurisdiction,[21] or that the German-Danish cross-border solar photovoltaic electricity auction was launched in 2016 (International Energy Agency, 2016b), or indeed, when the European Commission included plans supporting (and requiring) subsidy sharing in Article 5 of the latest Renewable Energy Directive draft (European Commission, 2016c). Remaining cognisant that the 'green energy contributions' conversation regarding joint, cross-border schemes will be 'null and void' post-2020 once national RES targets are relinquished for 2030, issues surrounding cross-border subsidisation of RES-E on a supranational scale will remain, and potentially increase due to heightened levels of both RES-E generation and installed interconnection capacity.

4.5.3 Considerations associated with a consumption-based alternative approach

Complexity, complexity, complexity. This proposal ensures much of it. Calculating the locations where renewable electricity is generated, how much is transferred, where it actually consumed, et cetera, is all involved work. Nevertheless, the alternative is to continue to use a methodology which may not be fit for purpose. Increasing the installed capacity of different renewable energies both in Europe and globally adds to the already multifaceted world of the electricity sector. As the penetration of renewable energies increase, as does the need for

[20] For more information, see: http://www.reuters.com/article/eu-energy-idUSL6N0PE24C20140703 and http://curia.europa.eu/juris/liste.jsf?num=T-47/15

[21] The amount of 'green energy' contributed toward national RES targets would depend on the level of investment in the joint project.

interconnection, support mechanisms, along with issues surrounding the ‘missing money’ problem, price distortions, and many more. While this chapter does not provide the solutions to all these issues, it may be seen in a similar light to that published by Ji et al. (2016) as a ‘thought-provoker’, one that tries to unearth a different way of thinking about the future electricity sector.

Further research is necessary in numerous areas to add layers to this proposal. For instance; the identification of regulatory and institutional barriers is essential for any movement towards a new approach for calculating RES-E shares and establishing a framework around the cost inequality issue, identifying how to best approach this redistribution of costs are two important areas of research.

4.6 Conclusion

This chapter proposes an alternative approach for quantifying the RES-E share of individual countries based on the volume consumed rather than produced to address potential inadequacies associated with the modern-day approach. As global power sector portfolios are undergoing a technology transformation to achieve carbon-neutrality over the long-term, renewable generation is fundamental to the cause along with high levels of interconnection to help facilitate the transition and remain as part of the enduring solution.

While increased interconnection capacity adds to the operational aspect of system control as non-synchronous RES-E can be safely and securely managed without curtailment being the first option, it also exacerbates an underlying issue with price distortions stemming from out-of-market financial support schemes that can decrease wholesale market prices. A paradox exists: as renewable generation (receiving out-of-market support) increases, wholesale electricity prices decrease, becoming more attractive to export at a price that is *not* truly reflective of the cost to generate that power. Consequently, this price distortion creates a cost inequality as consumers are left to remunerate the renewable electricity producer while the energy is consumed out of state. Using the EU Target Model as a case study, this chapter provides an awareness to the potential volume and scale of the issue in a sector aiming for long-term de-carbonisation. The chapter shows that even in a conservative 2030 scenario that significant volumes of renewable electricity is likely to be transferred on annual basis. This approach should not be considered exclusive for Europe, instead it could be thought of as being applicable to any region with a similar nexus between renewable electricity generation and interconnection to surrounding systems.

This chapter suggests that tackling price distortions associated with renewable generation support mechanisms may be best approached from a supranational perspective. An agency, such as ACER within the EU, could provide the solidarity needed for cost equality to thrive, thereby maximising societal welfare for all electricity consumers in the region. Appointed to administer the renewable electricity affairs of a region, this agency should take cognisance of individual economic, societal, technical and environmental conditions to create a level playing field, free of price distortion created by differing support structures. An agency responsible for accurately quantifying renewable electricity shares and remunerating producers from the country that consumed their electricity instead of where it has been produced – effectively socialising the cost of renewable electricity across state boundaries to improve cost equalities during the transition to a decarbonised system.

Increasing the accuracy of cost distributions associated with the consumption of renewable electricity may also provide secondary gains. Aside from reducing the level of revenue required to remunerate RES-E generation in an exporting country, this approach may lower the economic barriers surrounding the cost to consumers of developing higher levels of RES-E capacity. If, for example, a country has the correct topography and climate for hydro-powered generation, then the cost as well as the benefit of this renewable energy source can be shared with neighbouring nations – aligning with aspects present in the Renewable Energy Directive around subsidy sharing, joint projects and statistical transfers, improving investment signals and issues surrounding long-term security of electricity supply.

The complexity associated with quantifying RES-E based on the proposed approach will be significantly higher than the status quo. The alternative is to continue to use, what may be perceived as an increasingly inaccurate methodology. Measuring RES-E by production may be viewed as a ‘quick and easy’ approach, however as electricity markets worldwide become more intrinsically linked and transition toward a de-carbonised sector with high renewable generation capacity, simplicity may no longer be the correct strategy for reasons alluded to.

Chapter 5: Comparing negative emissions and high renewable scenarios for the European power system

5.1 *Abstract*

Emerging literature highlights the essential role played by decarbonised electricity generation in future energy systems consistent with the Paris climate agreement. This analysis compares the impacts of high levels of renewable electricity and negative emissions technologies on exploratory visions of the future EU power system in 2050 in terms of emissions reduction, technical operation and total system costs. We show that high renewable power system scenarios coupled with low levels of negative emissions technological such as biomass carbon capture and storage (approximately 2% of installed capacity) could deliver negative emissions for the Europe power system without breaching published sustainable biomass potentials in Europe (or requiring imports) or geological storage potentials. Direct air capture increases this further but with associated higher costs. While carbon capture and storage and bioenergy carbon capture and storage must overcome market, regulatory and social acceptance challenges, given their potential benefits to emissions reduction and system operation their role in a future power system should be further explored.[1]

Keywords: Negative emissions; Direct air capture; Carbon capture and storage; European power systems; Paris climate agreement; High renewable energy power systems.

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[1] Submitted for review as: Gaffney, F., Deane, J., Drayton, G., Glynn, J. & Gallachóir, B. Ó. Comparing negative emissions and high renewable scenarios for the European power system. Applied Energy (2019).

5.2 Introduction

Decarbonising electricity generation is a key element in achieving the Paris climate agreement (UNFCCC, 2015) for limiting average global temperature rise to 'well below 2ºC' above pre-industrial levels. Multiple analyses involving varied levels of effort, technological development and policy support have explored the roles of high levels of renewable electricity, low carbon nuclear power, increased energy efficiency, and carbon capture and storage (CCS) on power system decarbonisation in Europe (Capros et al., 2013; Capros et al., 2016; European Climate Fund, 2010; European Commission, 2011; International Energy Agency, 2017b; International Energy Agency. Office of Energy Technology, 2006; IPCC, 2014; Krey and Clarke, 2011). However, the ratification of the Paris agreement demands a radical decarbonisation of the energy system (Glynn et al., 2018) and may require certain sectors within the economy to achieve net negative emissions (Grubler et al., 2018; Kriegler et al., 2018; Rogelj et al., 2018; Rogelj et al., 2015; Strefler et al., 2018; van Vuuren et al., 2018). Furthermore, a recent report by the Intergovernmental Panel on Climate Change highlights the importance of carbon dioxide removal and net negative emissions to achieving the goals of the Paris climate agreement (IPCC, 2018). Combining bioenergy with carbon capture and storage technology (BECCS) and/or the use of direct air capture (DAC) offers the prospect of electricity supply with large-scale net negative emissions (Chen and Tavoni, 2013; Marcucci et al., 2017). There are challenges and risks associated with both CCS and DAC technologies, such as the availability and provision of the biomass required for BECCS, the storage of CO_2 and the financing of such plants (Davis et al., 2018; Kapetaki and Scowcroft, 2017).

Much analysis has been undertaken on understanding high variable renewable futures (Clack et al., 2017; Collins et al., 2017; Deane et al., 2015a; Esteban et al., 2018; Gaffney et al., 2018; Gils et al., 2017; Heard et al., 2017; Heuberger and Mac Dowell, 2018; IRENA, 2016; Jacobson et al., 2017; Jacobson et al., 2015; Jacobson et al., 2018; Liu et al., 2018; Maïzi et al., 2018; Pietzcker et al., 2017; Pleßmann and Blechinger, 2017; Rogelj et al., 2018; Song et al., 2018) using cost optimal capacity expansion models and unit commitment and economic dispatch (UCED) models (Brown et al., 2018b; De Sisternes et al., 2016; Després et al., 2017; Heuberger et al., 2017a; Heuberger et al., 2017b; Schlachtberger et al., 2018; Schlachtberger et al., 2017; Sepulveda et al., 2018), less analysis has been undertaken in comparing with negative emission power system scenarios. The use of cost optimal long term expansion tools to develop scenarios assumes rational behaviour and market equilibrium in future power system, however

Trutnevyte (2016) shows that cost optimization may not approximate the real-world transition while near-optimal scenarios can encapsulate the real-world transition. Here we use three near-optimal scenarios to examine and compare ‘negative emissions’ and ‘high renewables’ scenarios, in what may be described as a discrete scenario analysis for the year 2050.

In this chapter we use a power system model with high temporal and technical resolution to investigate decarbonisation scenarios in terms of emissions reduction, technical operation and system costs. The analysis compares a power system with high levels of variable generation to one with negative emissions technologies (NETs), i.e. BECCS and/or DAC. These exploratory scenarios, with varying portfolios, meet the same electricity demand and use the same fuel price assumptions. This allows for direct comparative analysis and are not proposed to be optimal portfolios. Furthermore, this analysis limits the bioenergy resource availability (Ruiz et al., 2015) and geological storage potential of CO_2 (Dooley, 2013; Lewis et al., 2009; Vangkilde-Pedersen et al., 2009) to within published potentials for Europe.

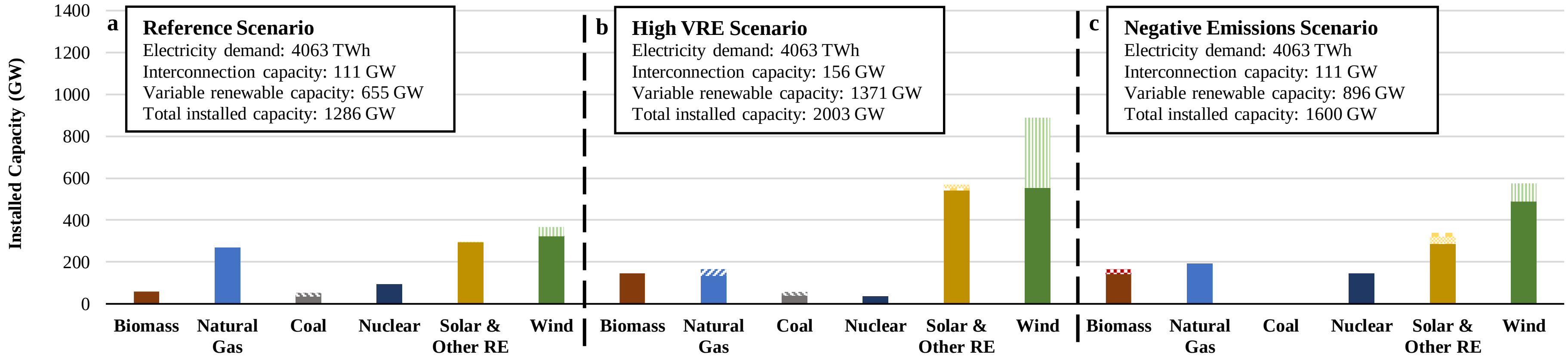
In an effort to promote transparency, the PLEXOS® model with all associated data is freely available online for academic research here.

5.3 Methodology

5.3.1 Analytical approach

We simulate a future pan-European electricity system containing 30 European countries (EU-27 plus the United Kingdom, Switzerland and Norway) at 5-minute resolution using PLEXOS® Integrated Energy Modelling software (Energy Exemplar); a unit commitment and economic dispatch modelling tool that optimises, at least cost, the technical operation of a system while respecting operational constraints. Exploratory scenarios for 2050 are developed based on technology, cost and demand projections from three sources: 1) the European Commission’s ‘EU Reference Scenario 2016’ (Capros et al., 2016) report in particular the Reference scenario; 2) the European Commission’s ‘Energy Roadmap 2050’ (European Commission, 2011) report, specially the Low Carbon scenario and; 3) the International Energy Agency’s ‘Energy Technology Perspectives 2017’ report (International Energy Agency, 2017b), specifically the Beyond 2ºC scenario. Hereafter, the scenarios are referred to as ‘Reference’, ‘High VRE’ and ‘Negative Emissions’ respectively.

The Reference scenario acts as a benchmark for current policy and market trends in the European Union (EU) and as such, can help inform future policy making (Capros et al., 2016). Assuming binding greenhouse gas (GHG) and RES 2020 targets are achieved along with the successful implementation of supranational energy and climate policies adopted before December 2014, the Reference scenario projects the EU energy system, transport and GHG emissions developments to 2050. The Energy Roadmap 2050 report outlines several scenarios aiming to reduce GHG emissions by 85-90%, when compared to 1990 levels, by 2050. Attempting to discover a balance between decarbonisation, security of supply and competitiveness risks with economic, technical and market forces, the Energy Roadmap 2050 High RES scenario provides the basis for the High VRE scenario in this analysis. While also aiming to decarbonise, the IEA's ETP 2017 report provides a different perspective from that of the European Commission (EC) on the future European power system. The ETP report includes two scenarios associated with limiting the global temperature rise to 2ºC. One of which, results in a carbon negative power system (Beyond 2ºC Scenario) and hence is the basis for the Negative Emissions scenario in this analysis. An overview of the scenarios for the target year 2050 plus variants of each, creating nine scenarios in total, are shown in Figure 5.1.



d Scenarios		Fossil Fuel Generation with CCS		Negative Emission Technology		Enabling Technology			Variable Generation
Central	Variants	Natural Gas-CCS	Coal-CCS	BECCS	DAC	Power-to-gas	High Interconnection	Demand Response	High VRE
Reference	REF	X	X						
	REF – No CCS								
	REF – DAC	X	X		X				
High VRE	H-VRE	X	X			X	X	X	X
	H-VRE – No CCS					X	X	X	X
	H-VRE – DAC	X	X		X	X	X	X	X
Negative Emissions	NE			X				X	
	NE – No CCS							X	
	NE – DAC			X	X			X	

Figure 5.1: Scenario overview for the EU-27 plus the United Kingdom. a, b, c, Represent the installed generation capacity in the Reference, High VRE and Negative Emissions scenarios respectively. The patterned areas associated with Biomass, Natural Gas and Coal indicate their respective CCS capacities. The patterned area associated with Solar & Other RE represents the Other RE within the stack, while the patterned area in the Wind stack represents Offshore Wind. Solar includes both Photovoltaic (PV) and Concentrated Solar Power (CSP). d, presents an overview of the variants associated with the three main scenarios analysed in this chapter. Country-specific details of all installed generation capacities are available in Appendix B. Variable renewable capacity includes Onshore and Offshore Wind, Solar PV and Other RE (e.g. Ocean). Inputs and results will be shown throughout this chapter for the EU-27 plus the United Kingdom to align with the original sources of the scenarios. The Reference scenario demand projections are applied across all scenarios with installed generation capacities adjusted linearly to ensure robust direct comparative analysis can be drawn between scenarios.

5.3.2 Scenarios in focus

While differing mainly in magnitude, overall system conditions in the High VRE and Negative Emissions scenarios have several similarities regarding the future power system. Both assume carbon capture technology and nuclear power will play a role in the future system, as will natural gas-fired generation. Scenarios differ with respect to VRE, specifically the amounts of wind and solar power. In the year 2050, VRE accounts for 56% of overall generation capacity in the Negative Emissions scenario compared to 68% in the High VRE scenario. Power-to-gas (PtG) plays an enabling role in variable renewable electricity integration in the High VRE scenario and is sized to alleviate any issues related to VRE curtailment. Mitigation scenarios also differ in terms of the primary fuel source that carbon capture technology is associated with. The Negative Emissions scenario for example, applies CCS to bioenergy generation capacity only, in contrast to the High VRE scenario which assumes natural gas- and coal-fired generation capacity alone utilise carbon capture and storage technology. Sensitivity analyses are carried out on several aspects of the mitigation scenarios, including complete removal of CCS, to achieve a greater understanding of their respective effects on overall power system decarbonisation, technical operation and total system costs. Regional bioenergy resource potentials restricts the amount of woody biomass available to 5.2 EJ (Ruiz et al., 2015) (median estimate, equates to 2-5% of the estimated total sustainable bioenergy potential globally (Smith et al., 2016)) and no imports are assumed outside of the European Union.

This compares to a value of 2.3 EJ (Capros et al., 2016) used for power generation in 2015. This analysis does not consider any indirect land use change impacts or direct impacts. Limiting the regional biofuel resource potential did not result in a binding constraint in any scenario. Across the three core scenarios, 53-69% of the potential was consumed however competition for this resource from areas outside of power system is not considered. Equally the transport and storage of captured carbon is limited in some countries, such as Austria, Cyprus, Estonia, Finland, Malta, Portugal, Sweden where geological capacity for storage is negligible (Dooley, 2013; Lewis et al., 2009; Vangkilde-Pedersen et al., 2009), consequently in this chapter, CCS capacity is not introduced in these Member States. Country-specific volumetric CO_2 storage constraints sourced from Vangkilde-Pedersen et al. (2009) and Lewis et al. (2009) were included in the analysis. This did not result in a binding constraint in any scenario. For context; the largest regional storage required for the single year under investigation was 131 million tonnes compared to estimates of 117-360 billion tonnes of storage by Vangkilde-Pedersen et al. (2009).

Direct air capture (DAC) technology is also considered. While not initially incorporated into any of the three core scenarios, the technology is introduced as a ‘further step to decarbonisation’ across all scenarios. Designed to extract carbon dioxide directly from the atmosphere, DAC is introduced to evaluate the effects on systems with different CO_2 intensities (Keith et al., 2018; Smith et al., 2016; Socolow et al., 2011). In the analysis, DAC capacity is limited to consume 1% of electricity demand in each individual country over the year. Further details are available in Appendix B. Although this is an arbitrary limitation, it does provide insights into both the carbon production increase associated with power generation and the carbon captured through the process. It is assumed that DAC operates using electricity and natural gas in unison, as per Keith et al. (2018).

5.3.3 Model simulation

Using PLEXOS® Integrated Energy Modelling software (PLEXOS®), technical characteristics associated with thermal generation capacity, such as ramp rates or minimum generation levels for example, are all binding while an optimised dispatch of thermal, renewable and storage capacity is created (Deane et al., 2017; Deane et al., 2014; Drayton et al., 2004; Welsch et al., 2014). The software is transparent with all equations used in the optimisation available in the form of LP files in each simulation. In this analysis PLEXOS® is used to assess the technical feasibility of each scenario in addition to the level of decarbonisation achieved across the region within scope.

While the input data such as wind, solar and demand is hourly in nature, PLEXOS® linearly upscales the data to 5-minute resolution. Sub-hourly temporal resolution offers the added benefit of examining the technical ability of generation portfolios to achieve different levels of power output in short temporal timeframes as shown by Deane et al. (2014). For example, there is a higher likelihood ramp rates and other technical aspects of thermal generation will bind at 5-minute resolution compared hourly dispatch. Deane et al. (2014) show that increasing temporal resolution increases the accuracy of estimating start cost of thermal power generation capacity.

5.3.4 Input Data

The EC (Capros et al., 2016; European Commission, 2011) and IEA (International Energy Agency, 2017b) reports provide information on generation portfolios, electricity demand and observed trends on a supranational and/or national scale, where possible. ENTSO-E (2018b) and Delucchi et al. (2016) provided guidance on VRE installed capacities on a country level for the mitigation scenarios while all other capacities were scaled from the counterfactual. Applying this information facilitated our need to accurately replicate conditions assumed in each report. Calculating the average capacity factor of hydro, nuclear, or biomass for example, allows us to implement constraints in the model to achieve high correlation to each source. As the only two non-EU Member States when these reports were published, no data was available for Switzerland or Norway from the listed sources, thereby power system data was created using the best data available for each country (Albrecht, 2013; Albrecht et al., 2012; Delucchi et al., 2016; ENTSO-E, 2016c, 2018b; Swiss Federal Office of Energy, 2017). See Appendix B for more details.

Generation capacities are categorised by class, e.g. hydro, oil, gas, solids, biomass/waste, et cetera. Portfolios are disaggregated into individual power plant types by fuel class and assigned standard technical characteristics as shown in Table 5.1, an approach previously used by Gaffney et al. (2018). Thermal generation efficiencies are aligned with International Energy Agency (2017b). Hourly generation profiles for wind power and solar photovoltaic were obtained from Gonzalez-Aparicio et al. (2016) and Pfenninger and Staffell (2016a) respectively for each country. Concentrated solar power with thermal storage was modelled using an approach outlined by (Denholm and Hummon, 2012; Denholm and Mehos, 2014; Denholm et al., 2013) with a 9-hour storage capacity aligning with the latest installations (National Renewable Energy Laboratory, 2017) and a 60% flat heat rate(Denholm et al., 2013). A solar multiplier of 2 was used, which as the literature (Denholm et al., 2013; National Renewable Energy Laboratory, 2017) explains is the ratio between the solar field and the power block output. A 20% start-up loss and minimum stable level set at 40% of max generation, as recommended by Denholm et al. (2013), were included. Other RE was assumed to be primarily ocean energy. Generation profiles and installed capacity distribution among European countries was carried out in alignment with Jacobson et al. (2018). Individual hydro profiles were decomposed from monthly generation constraints from ENTSO-E (ENTSO-E, 2012) to weekly and hourly profiles in the optimisation algorithm function within PLEXOS®. Pumped hydro energy storage information was sourced from the IEA's 'Electricity Information' publication (International Energy Agency) with 9 hours of hydro storage assumed. CCS was modelled using the in-build functionality in PLEXOS® software to represent the technology – 90% capture rate is assumed. To represent BECCS assumptions from the '2006 IPCC Guidelines for National Greenhouse Gas Inventories' (Gómez et al., 2006) publication regarding the biogenic carbon content of biomass (100gCO_2 kWh^{-1} (Anderson and Peters, 2016; Gómez et al., 2006)) are applied with a 90% capture rate applied to assess the amount of CO_2 capture from the process which can offset emissions from other technologies. Generation capacity associated with CCS technology received priority dispatch over thermal power generation capacity. Details of the standardised generation characteristics are outlined in Table 5.1.

Table 5.1: The standardised generation characteristics applied for all 30 countries. Biomass/waste assumes biomass integrated gasification combined cycle (BIGCC) technology is in place, aligning with International Energy Agency (2017b) assumptions. * DAC installed capacity varies as it is based on consumed 1 % of country-specific demand. ** Power-to-gas installed capacity varies by country based on each country's level of VRES, i.e. level of low-cost power. See Appendix B for further details. *** Power-to-gas efficiency combines the process of converting power-to-gas in the first stage and then back to power in the second stage using CCGT technology.

Fuel Type	Capacity (MW)	Start Cost (€/MW)	Min Stable Factor (%)	Ramp Rate (MW/Min)	Efficiency (%)
Biomass/waste	300	33.3	30	5	51% (43% - CCS)(International Energy Agency, 2017b)
Geothermal heat	70	42.9	40	5	-
Hydro (lakes)	150	0	0	10	-
Hydro (run of river)	200	0	0	10	-
Natural gas CCGT	450	177.8	40	20	62% (54% - CCS)(International Energy Agency, 2017b)
Natural gas OCGT	100	100	20	50	40%(International Energy Agency, 2017b)
Nuclear	1200	100	60	5	-
Oil	400	187.5	40	5	45%(International Energy Agency, 2017b)
Solids	300	266.7	30	5	48% (41% - CCS)(International Energy Agency, 2017b)
Pumped hydro	200	0	0	30	80%(Jacobson et al., 2018)
Demand response	200	0	0	30	90%
Direct air capture	4 - 756*	N/A	N/A	N/A	-
Power-to-gas	59 – 30897**	N/A	N/A	N/A	36%***

Hourly resolution demand curves were attained from 30-year Member States level historic data from the EC's Joint Research Centre and linearly scaled to the overall demand estimates used for each scenario (European Commission, 2017b). In the mitigation scenarios it is assumed that demand-side management capabilities for each Member State sized at 5% of peak demand with a power capacity of 5 hours, an assumption well within the range analysed by the European

Climate Foundation (European Climate Fund, 2010) which investigated capabilities of up to 20%. Power-to-gas is included in the High RES scenario to increase the level of storage in a system with significant levels of variable generation (Gahleitner, 2013; Götz et al., 2016; Jentsch et al., 2014; McKenna et al., 2018; Schiebahn et al., 2015). The process, outlined in the Energy Roadmap 2050(European Commission, 2011), converts excess power into hydrogen which is mixed, at max 30%, with natural gas which is converted back into power through natural gas thermal generation capacity. The ETS carbon price is not applicable to the share of natural gas derived from power-to-gas. Power-to-gas is included in PLEXOS® as a demand that purchases low cost power which is converted into gas assuming a conversion efficiency of 60%. The balance between the volume of power purchased and the amount converted back into power at max 30% dilution with natural gas is maintained through post-processing, i.e. multiple simulations and calibration. DAC is included in variant scenarios to assess the technologies overall impact if adopted. It is assumed DAC captures 2.73 tCO_2 MWh^{-1} (Socolow et al., 2011) with a capacity factor of 90%. The latter has a bearing on the installed capacity assumptions and therefore the CAPEX calculations. Energy requirements for each tonne of CO_2 capture from the atmosphere are 0.366 kWh of electricity and 5.25 GJ of natural gas. The fuel and ETS carbon costs related to the natural gas used with DAC are accounted for in the total system costs calculations.

ENTSO-E's 'Ten Year Network Development Plan'(ENTSO-E, 2016c) provided the basis for transmission capacity assumptions between countries. The High RES scenario deviates away from this assumption as per Attachment 2, Energy Roadmap 2050 part 2 (European Commission, 2011). Interconnection is limited to net transfers between countries and excludes interregional transfers in line with the EU day-ahead market schedule dispatch clearing algorithm, EUPHEMIA (EPEX Spot, 2016; N-SIDE). Malta is the only electrically isolated country modelled. See Appendix B for more details.

Coal, oil, natural gas and biomass prices remain consistent across all scenarios at €24, €109, €65 (Capros et al., 2016) and €31 (Ruiz et al., 2015) per barrel of oil equivalent respectively ($€_{2015}$). Biomass price is based on the average assumed for dedicated perennial biomass crops, forest products and primary forest residues from Tables 11 & 14, Ruiz et al. (2015). Emissions Trading Scheme carbon price is assumed €88 per tonne in the Reference scenario and €264 per tonne in the Negative Emissions and High RES scenarios, aligning with assumptions made by the European Commission (Capros et al., 2016). To contain the level at which Norwegian hydro capacity could distort cross-border power transfer and consequently, market prices across

Europe, the annual capacity factor for hydro was restricted to 50% of its potential generation capacity which is based on observed system trends over recent years (ENTSO-E, 2016a, 2017b; Eurostat, 2016; Swiss Federal Office of Energy, 2017).

5.3.5 Total system cost assessment

Total system costs are calculated using data from multiple sources (Capros et al., 2016; Carlsson, 2014; ENEA Consulting, 2016; Grosse R et al., 2017; McDonagh et al., 2018; Rubin et al., 2005; Tsiropoulos et al., 2017). Technical lifetime, capital expenditures, fixed and variable operation and maintenance costs were all taken from the listed sources using the central option where possible, see Table 5.2 for specifics. This analysis aligns with its use of the term 'total system costs' with that of the European Commission (2014b), meaning that carbon-related costs are not accounted for in the calculation since they are not seen as an "extra cost" from a societal perspective. Total system costs are annualised, undiscounted costs (i.e. no interest rates applied) where the CAPEX is spread over the technical lifetime of the technology with variable costs also included. 50% of transmission capacity between the EU-27 plus the United Kingdom connected to Norway and Switzerland is accounted for in cost calculations, representing bilateral arrangements in place to build and maintain interconnection.

Table 5.2: Cost assessment assumptions for the various aspects to be considered (€$_{2015}$). References: [1] (Tsiropoulos et al., 2017), [2] (Grosse R et al., 2017), [3] (Carlsson, 2014), [4] (Keith et al., 2018), [5] (ENEA Consulting, 2016), [6] (McDonagh et al., 2018), [7] (Rubin et al., 2005). *VOM (€ per tCO_2 captured). ** DAC CAPEX was reverse calculated from values used in Keith et al. (2018), i.e. CAPEX equalling $694mn per million tonnes of CO_2 captured. *** based on a technical lifetime of approximately 40,000 hours.

Type	Lifetime (Year)	CAPEX (€/kW)	O&M Costs (% CAPEX)	FO&M (€/kW)	VO&M (€ MWh^{-1})
Biomass/Waste [1]	25	4,070	2		
Biomass-CCS [1]	25	5,800	2.3		
Geothermal heat [1]	30	6,030	2		
Hydro [1]	60	1,400	0.5		
Natural Gas [2]	30	1,000		4	5.00
Natural Gas-CCS [1]	30	1,510	2.5		
Nuclear [3]	60	5,324	2		
Oil [2]	30	1,810		7	0.60
Other RE [1]	20	3,675	4.45		
Solar PV [1]	25	560	2.5		
Solar CSP [1]	30	4,200	1.7		
Solids Fired [2]	35	2,200		6	5.00
Solids Fired-CCS [1]	40	2,580	2.1		
Wind Onshore [1]	25	1,190	3		
Wind Offshore [1]	30	2,710	2		
PHES – Upgrade [3]	60	276		4	0
Interconnection (€/km) [3]	60	452,070	3.5		
Direct Air Capture [4]	25	16,571**			21.28*
Power-to-gas [5], [6]	5***	790	2		

Carbon Transport & Storage [7]					17.53*

5.4 Results and discussion

5.4.1 Operational conditions across different decarbonisation pathways

Error! Reference source not found.(a) gives an overview of electricity generation by fuel share and projected VRE curtailment levels. The figure shows curtailment levels increasing with greater reliance on VRE generation, however one can also see the dependency on PtG technology to manage VRE curtailment in the High VRE scenario. Reducing VRE curtailment further through PtG is not addressed in this analysis. **Error! Reference source not found.**(a) shows dispatchable RE generation remaining between 22-24% across each scenario while low carbon generation (renewables plus nuclear power) exceeds 88% and 92% in the High VRE and Negative Emission scenarios respectively. Consequently, fossil fuel-fired generation decreases in the mitigation scenarios which reduces Europe's fossil fuel import dependency, and therefore contributes to increased security of supply for the region. Compared to the counterfactual (75%), the Negative Emission and High VRE scenarios consume 34% and 51% fossil fuels respectively.

Error! Reference source not found.(b) shows thermal power plants experiencing reduced capacity factors in the mitigation scenarios when compared to the counterfactual. While we would expect unabated generation to decrease, **Error! Reference source not found.**(b) also shows that capacity factors for abated generation (Natural Gas-CCS and Coal-CCS) are relatively low, ranging between 44-47%, while BECCS is operates at full capacity in the mitigation scenarios. This analysis, by means of **Error! Reference source not found.**(b), shows that unabated generation (biomass, coal and natural gas) has a dispatched capacity factor from 18-35% depending on the mitigation scenario.

Error! Reference source not found.(b) also alludes to another noteworthy point associated with system dispatch. The figure shows low capacity factors for dispatchable capacity in the High VRE scenario compared to the Negative Emissions scenario. This reduction in synchronous generation capacity impacts on a system's kinetic energy level, otherwise known as inertia; a necessary element for maintaining secure, reliable power through frequency stability(Daly et al., 2015). Synchronous dispatchable generators such as nuclear, coal, natural gas and biomass that contain mass mechanical components whose rotation is synchronised with the system frequency can provide system inertia. Inertia can be thought of as a 'glue' that keeps generating units synchronised in the power system, allowing the system to deal effectively with fast changes in frequency(ENTSO-E, 2016b). Batteries, demand response and fast frequency response technologies are, in theory, able to provide active power in very short (sub-second) timescales and can partially substitute for mechanical inertia (Vivid Economics and Imperial College London, 2018). Furthermore, the behaviour of large electricity system under very low levels of inertia, coupled with the volume of frequency response needed to stabilize a large power system are not well understood.

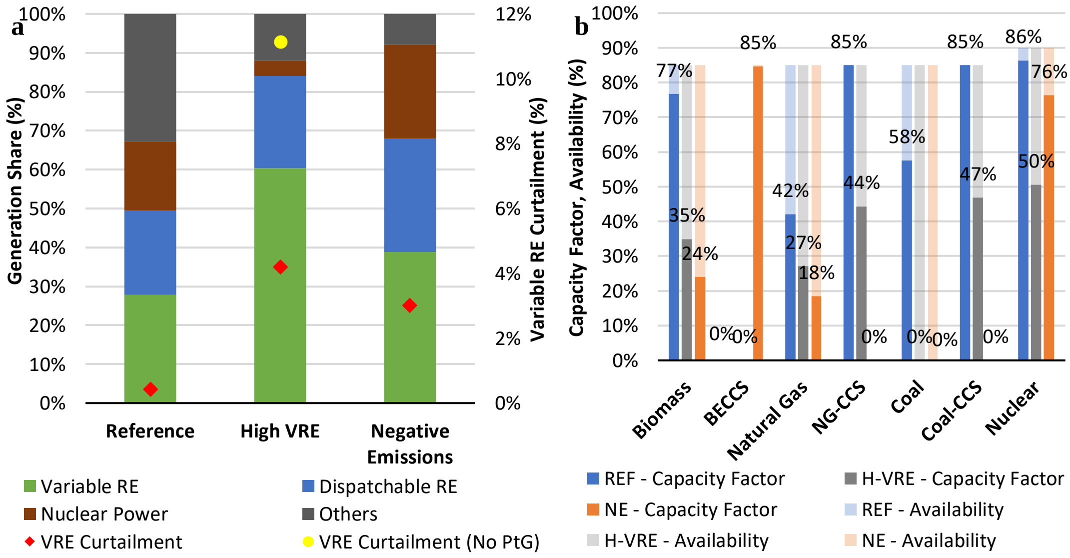


Figure 5.2: Power generation characteristics for the EU-27 plus the United Kingdom. a, Represents the disaggregated total generation share and system-wide variable RE curtailment. b, Represents the capacity factor and availability for a selection of generation classes. Dispatchable RE accounts for biomass, hydro and solar CSP. Variable RE generation accounts for onshore and offshore wind, solar photovoltaic, geothermal and other RE. VRE curtailment (No PtG) in (a) is associated with the High VRE scenario only as others do not include power-to-gas technology.

5.4.2 Decarbonisation and the impact of NETs

The gross CO_2 production and CO_2 capture for the main scenarios, with and without DAC, is shown in Figure 5.3(a). The figure contextualises the CO_2 produced versus that which is captured through CCS, BECCS and/or DAC across the scenarios. The Negative Emissions scenario achieves a CO_2 intensity of -7.5 $kgCO_2$ MWh^{-1} (31 million tonnes of CO_2 ($MtCO_2$) sequestered) compared to 21.5 $kgCO_2$ MWh^{-1} (92 $MtCO_2$ emitted) for the High VRE alternative across the year. The figure shows a small increase in gross CO_2 production associated with the inclusion of DAC when compared to the additional emissions captured from the technology. Furthermore, this analysis finds that the average 'CO_2 capture to CO_2 gross emissions' ratio was 10:1 across the three scenarios. With respect to the role CCS technology plays in each scenario, Figure 5.3(a) demonstrates the level of decarbonisation for each scenario where no CCS was made available. In doing so, we identify the reliance of each scenario on negative emission technologies to achieve projected levels of decarbonisation. In summary, Figure 5.3(a) identifies 1) the system-wide CO_2 intensity differential between scenarios, 2) the reliance of all three scenarios on CCS technology, specifically the switch with respect to CO_2 intensity between the decarbonisation scenarios when no CCS is included (i.e. High VRE having a lower CO_2 intensity) and 3) the potential CO_2 intensity gains from including DAC.

As a sensitivity on the High VRE scenario, the possibility of BECCS replacing Coal-CCS generation capacity in the portfolio is considered (referred to as 'High VRE - BECCS'). From a decarbonisation perspective alone, our analysis shows that promoting BECCS over Coal-CCS could potentially save an extra 74 $MtCO_2$, yielding a further 17.4 $kgCO_2\ MWh^{-1}$ reduction in CO_2 intensity, as shown in Figure 5.3(b). Further details are available in Appendix B.

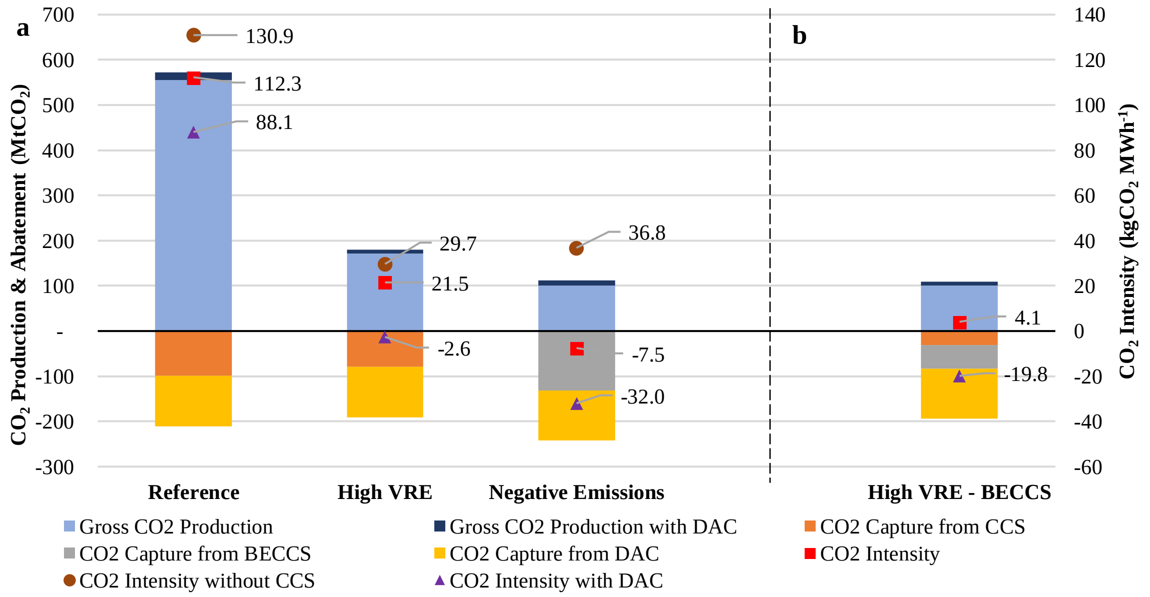


Figure 5.3: Gross CO_2 production, CO_2 capture and CO_2 intensity for the scenarios. a, Represent the main scenarios. b, Represents High VRE sensitivity regarding BECCS replacing Coal-CCS, for more details see Appendix B. The Gross CO2 Production w. DAC represents the additional carbon emissions produced due to increased demand from DAC. In alignment with technology assumptions from the IEA ETP 2017 publication(International Energy Agency, 2017b), BECCS sequesters 90ktCO2 GJ-1. For more details see Methods.

The influence of DAC is best appreciated from viewing the CO_2 intensities of each scenario in Figure 5.3. Assumed to capture 2.73 $tCO_2\ MWh^{-1}$ of input electricity(Keith et al., 2018), and recognising that the technology is best-optimised when powered by low carbon sources of energy, the analysis finds DAC most effective for achieving extremely low levels of decarbonisation in the scenarios where the CO_2 intensity is low to begin with, see Table 5.3[1]. For a net-negative scenario the CO_2 production increase can potentially be larger than the alternatives yet remain CO_2 net-negative. Assigning captured emissions from DAC to a specific sector in the economy remains an open question – we assume here it is attributable to the power sector.

Table 5.3: An overview of the energy requirements, gross CO_2 production increase, captured CO_2 and CO_2 intensities associated with using DAC for each of the main scenarios in 2050. System-wide CO_2 intensity is shown without DAC first, then with DAC but excluding CO_2 abatement from the technology because strictly speaking, it is not part of the power system. Finally, the CO_2 intensity is illustrated with the abated emissions from DAC included.

	REF – DAC	H-VRE DAC	NE – DAC
Electricity Requirement (TWh)	40.6	40.6	40.6
Natural Gas Requirement (PJ)	583	583	583
Gross CO_2 Production Increase (Million tonnes)	15.1	6.1	8.0
CO_2 Capture Increase (Million tonnes)	94.9	102.9	100.6
CO_2 Intensity without DAC ($kgCO_2\ MWh^{-1}$)	112.3	21.5	-7.5
CO_2 Intensity with DAC, excl. CO_2 Capture ($kgCO_2\ MWh^{-1}$)	115.1	23.2	-4.9
CO_2 Intensity with DAC, incl. CO_2 Capture ($kgCO_2\ MWh^{-1}$)	88.1	-2.6	-32.0

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5.4.3 Total system costs and the effect of carbon-related costs

This analysis aligns its use of the term 'total system costs' with that of the European Commission (2014b), meaning that carbon-related costs are not accounted for in the calculation since they are not seen as an "extra cost" from a societal perspective. Total system costs are shown as annualised, undiscounted costs where CAPEX is dispersed over the technical lifetime of the technology and variable costs are included. Carbon-related costs will be shown separately, as is the case in Figure 5.4(a). It must be noted that this analysis assumes issues highlighted by Zakkour et al. (2014) regarding current GHG emission frameworks not fully facilitating negative emissions technologies are resolved, thereby making negative emissions tradable to other carbon-intensive sectors that fall under the European ETS. In summary, Figure 5.4(a) illustrates that 1) the High VRE scenario is more expensive in terms of total system costs

[1] This alludes to an important assumption in this analysis where DAC is a constant demand across the horizon. If the technology was assumed flexible it could have greater effect on lowering its carbon intensity further by utilising low carbon electricity generation which would have a positive effect on system operations, i.e. flexible dispatchable demand that can help facilitate high levels of variable generation. This analysis explores DAC as a possible means to further decarbonise the sector. Further, in depth, analysis would be needed to create a business case for DAC which would account for the benefits of incorporating flexibility into the operational strategy. This is not the objective of this analysis.

and also carbon-related costs that the Negative Emissions scenario and 2) the Negative Emission scenario is cost-comparable to the counterfactual scenario when viewed on total system costs alone. The second point is interesting as it is an unexpected outcome of this analysis. In summary, the economics show that while the Negative Emission scenario costs approximately €51 billion more in annualised CAPEX terms for the entire European power system, the operational cost savings are similar; primarily due to fuel cost savings. The fuel cost savings for both decarbonisation scenarios compared to the reference scenario is approximately €50 billion.

When calculating an incremental cost that encapsulates the expense of generating electricity in each scenario, carbon-related costs are included since, in practice, these are passed directly to the consumer, see Figure 5.4(b). While excluding taxes/levies, the electricity costs shown in the figure are represented with and without carbon-related costs to isolate and illustrate the effect on the end-user. It is interesting to view the difference carbon-related costs make on the incremental cost of electricity for all the scenarios shown, along with the effect of including DAC technology to the core scenarios. To explore this further, Figure 5.4(c) reveals the change in total power system costs across the main scenarios when sensitivity analyses (±20%) are carried out on several cost elements of the power system. Of the categories under investigation, the analysis shows RE generation capacity CAPEX is the most sensitive to change, followed by Fuel & ETS price and thermal generation CAPEX third.

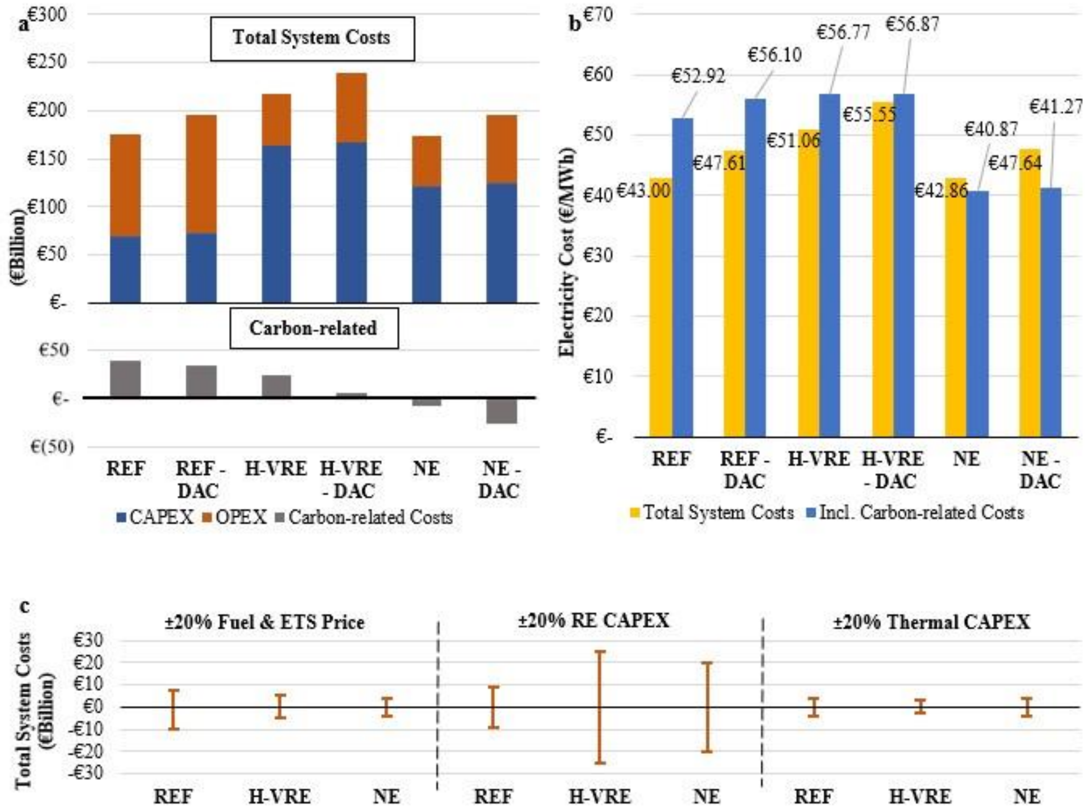

Figure 5.4: Disaggregated total system costs and electricity costs. a, Represents disaggregated total system costs (top) and carbon-related costs (bottom). For further data on total system costs see Appendix C. b, Represents the electricity cost per MWh delivered to the consumer across the year. These costs are effectively the total power system costs plus carbon-related costs relative to power consumed without any discounting included. c, highlights total system cost change via error bars when applying a ±20% cost sensitivity on various aspects of the system. Error bars on "±20% Fuel & ETS Price" sensitivity reflects the largest change from biomass, natural gas and ETS price assumption sensitivities modelled individually.

5.4.4 Average abatement costs

We do not calculate marginal CO_2 abatement costs in our analysis but instead calculate the average CO_2 abatement cost across the entire power system. Using the difference in total system costs and CO_2 emissions compared to the baseline, the cost associated with reducing each tonne of CO_2 released into the atmosphere, referred to here as average abatement cost, is calculated and presented in Figure 5.5(a). To expand on this concept of an average abatement costs using values from the analysis;

- REF: total system costs equal €174.7bn, producing 456.3 million tCO_2;
- H-VRE: total system costs equal €217.5bn, producing 91.7 million tCO_2;
- NE: total system costs equal €174.2bn, producing -30 million tCO_2.

Therefore, the H-VRE scenario cost €42.8bn more than the REF to reduce emissions by 362 million tCO_2, equating to an incremental average abatement cost of €118/tCO_2. The NE cost €0.5bn less than the REF to reduce emissions by 487 million tCO_2, equating to an incremental average abatement cost of €-1/tCO_2. In summary, for every tonne of CO_2 not released in the Negative Emissions scenario there is a €1 total system cost saving compared to the baseline. Alternatively, Figure 5.5(b) demonstrates the findings in terms of CO_2 emitted per million-euro total system cost expenditure. From a decarbonisation perspective one can see for every million-euro spent in the Negative Emissions scenario results in net-negative emissions, in contrast to both the Reference and High VRE scenarios.

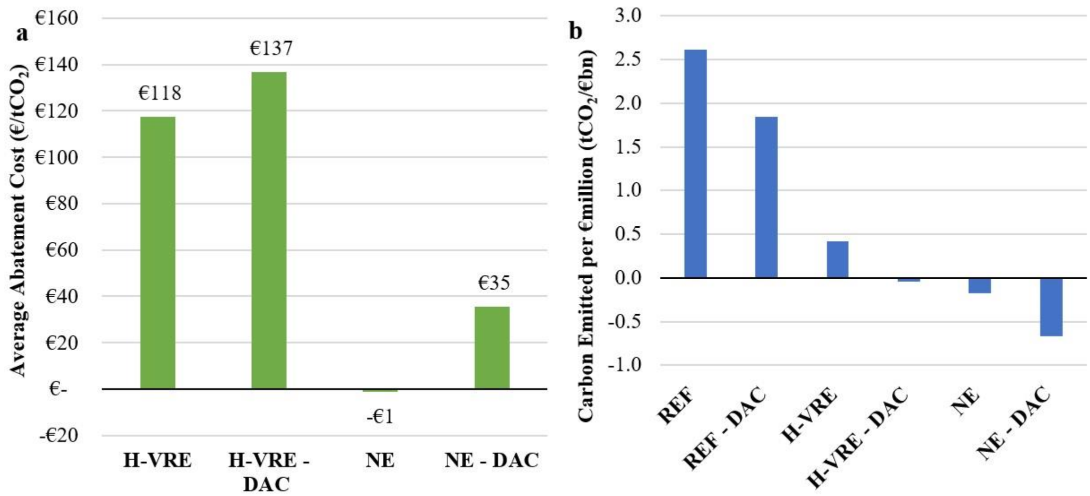

Figure 5.5: Average abatement cost for the mitigation scenarios (a) and carbon emissions released per €billion investment (b).

5.5 Conclusion

This chapter shows that a High VRE scenario can achieve very high levels of decarbonisation (21 $kgCO_2$ MWh^{-1}). We also show that a Negative Emissions scenario bound by regional biomass potentials and national CO_2 storage potentials can achieve a power system-wide CO_2 intensity reduction relative to the baseline scenario while remaining cost-comparable. Furthermore, converting less than 2% of the EU's installed generation capacity to BECCS consumes 69% of the projected available sustainable biomass while enabling the power system to achieve net-negative emissions (-7.5 $kgCO_2$ MWh^{-1}).

However, both technology readiness and technological choice play definitive roles in the results shown in this chapter. From a system decarbonisation perspective, we show that the state of readiness for CCS technology dictates whether the High VRE or Negative Emissions scenario achieves the lowest system-wide CO_2 intensity. Through the 'High VRE – BECCS' sensitivity, where BECCS replaced Coal-CCS capacity, the importance of technological choice was highlighted. In the High VRE scenario, the European Commission assumed that CCS technology would be an option in the year 2050 but do not associate the technology with biomass, instead opting for natural gas and coal. And finally, as a 'further step to decarbonisation', DAC technology was included to assess the potential benefits of the technology, even if readiness was an issue. It was found that an average CO_2 capture to gross emissions ratio of 10:1 across the three main scenarios was achieved using DAC, therefore highlighting the potential for meaningful contributions to achieving a decarbonised power system (once captured CO_2 is attributable to the power sector). The benefits of DAC shown here do not account for additional gains attributable to the technology being flexible and therefore only consuming electricity from low carbon sources. The concept of flexibility would also help facilitate more variable generation in a power system which would have operational benefits the system operator.

Notwithstanding the potential benefits of the abovementioned, risk exposures exist in several areas for NETs. Technology risk regarding the reliance on CCS coupled with questions over commercial readiness and scalability; operational risk where high concentrations of variable generation diminish generator capacity factors, market participant risk with market prices reducing due to the overall shift in the cost of energy from operational costs to capital costs and finally; consumer risk with incremental electricity costs varying widely and therefore run the risk of heightening budgeting concerns for the consumer.

The benefit of high temporal resolution dispatch modelling demonstrates that 1) abated generation such as coal and natural gas may not surpass 50% capacity factor in a High VRE scenario, 2) unabated biomass and natural gas generation endures capacity factors between 18-35% and 3) unabated coal has no place in either decarbonisation scenario. In short, we demonstrate that there is a balance to be found between the level of dispatchable generation installed, how much can be dispatched due to the merit order effect with vast amounts of zero-marginal cost generation, and what is needed to maintain a stable power system. While this analysis does not investigate the risks or challenges listed, we see this as the first step to a technically complete comparison of decarbonisation scenarios. Throughout this chapter we provide a view into the techno-economic aspect of optimally dispatched power systems under different decarbonisation pathways, highlighting concerns related to system operation (reduced capacity factors), economics (shrinking OPEX cost component of total system costs) and emissions reduction (questions over technology choice/reliance/readiness) along the way.

Chapter 6: Reliably providing highly renewable 100% emissions-free electricity across Europe benefits from incorporating dispatchable generation

6.1 *Abstract*

A recent study presented roadmaps for 139 countries delivering emissions reductions greater than required by the Paris climate agreement. The roadmaps are extremely ambitious and warrant significant scrutiny. Each roadmap proposes a near-100% electrification of all energy sectors (transportation, heating/cooling, industry, agriculture/forestry/fishing), in contrast to 19% electrification in 2018. In addition, the electricity systems in these roadmaps are 100% based on wind, sun and water. This chapter assesses the technical feasibility the 100% renewable Europe roadmap, by testing the results with a European power system model. This chapter does not explore whether it is feasible to electrify all sectors, nor does it address the societal barriers associated with installing the required scale of generation and transmission capacities. The analysis does show however, via detailed power system simulations, that an electricity supply close to 100% based on wind, sun and water may be technically feasible in Europe if system adequacy and reliability concerns are addressed. Furthermore, the analysis finds that allowing low levels of dispatchable generation capacity in high renewable systems can improve system reliability, can lower both VRE and transmission capacity requirements and reduce associated system supply costs by 25% while delivering a carbon neutral energy system.[1]

Keywords: WWS; 100% renewable energy systems; European power systems; Paris climate agreement; High renewable energy power systems.

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[1] Submitted for review as: Gaffney, F., Deane, J., Daly, P., Pfenninger. S., Staffell. I., Ó Gallachóir, B. 2019. 'Reliably providing highly renewable 100% emissions-free electricity across Europe benefits from incorporating dispatchable generation.' Nature Energy.

6.2 Introduction

Several recent studies have examined 100% renewable energy systems at global or national levels, with divergent views on their feasibility (Brown et al., 2018a; Clack et al., 2017; Heard et al., 2017; Jacobson et al., 2018). Due to the urgency of the climate action challenge, such studies receive substantial attention. Public controversies such as that surrounding Jacobson et al. (2015) and Clack et al. (2017) divergent views regarding a fully decarbonised U.S. energy system highlight the importance of the input assumptions and the capability of models used to determine the feasibility of such scenarios. Interestingly, energy research lags behind other scientific fields such as medicine or economics (Begley and Ellis, 2012; Downing, 2004) in moving to more open and reproducible science (Pfenninger, 2017; Pfenninger et al., 2017). The fact that this research is directly relevant to the urgent policy challenge of rapid energy system decarbonisation (DeCarolis et al., 2012; Nature, 2014) makes reproducibility of results particularly important.

Recently Jacobson et al. (2018) presented roadmaps for 139 countries delivering emissions reductions greater than required by the Paris climate agreement (UNFCCC, 2015). Each roadmap proposes a near-100% electrification of all energy sectors (transportation, heating/cooling, industry, agriculture/forestry/fishing), in contrast to 19% electrification today (International Energy Agency, 2018). The roadmaps also solely on vast amounts of weather-dependent variable renewable energy (VRE), primarily wind, water and solar (WWS) power, to meet electrical and thermal demand.

Both of these pathway components, i.e. complete electrification of energy systems and complete electricity systems driven by WWS are at times critiqued individually and also critiqued together. The focus of this analysis is on the ability of a WWS power system to deliver electricity when required. The ability of a full energy system to be electrified is not addressed in this analysis.

From a system perspective, flexibility in the WWS energy system is key to proposals. And while Jacobson et al. (2018) assume significant flexibility in demand and expanding interconnection capacity is not seen as an issue, there is relatively little dispatchable generation or long-duration storage. Some concerns regargind this challenge may be addressed by evidence of modern portfolio theory (Markowitz, 1952) and how complementing technologies can alleviate the issue, especially when coupled with the broadening of geographical areas (Brown et al., 2018c; Thellufsen and Lund, 2017), for example the European region contains

40 countries. Nevertheless, assessing system adequacy and overall reliability is an important aspect of planning an operable 100% renewable electricity system.

Here we examine the technical feasibility of a 100% renewable Europe, basing our results on a replication and extension of the Jacobson et al. (2018) study using a detailed and available European power system model. Applying input data from the aforementioned study, we aim to reproduce the highly electrified, highly renewable European energy system, testing the societally critical objective of providing a reliable power system whilst determining the relationship between variable generation, energy storage, transmission capacity and dispatchable power. We pay particular attention to concerns outlined in recent literature on 100% renewable energy systems (Brown et al., 2018a; Clack et al., 2017; Heard et al., 2017; Heuberger and Mac Dowell, 2018; Sepulveda et al., 2018; Trainer, 2012, 2013; Zappa et al., 2019) namely system adequacy, flexibility and stability. Displacing conventional power plants with renewable energy creates challenges due to increased supply-side variability (Collins et al., 2018) for example. These challenges are not examined by Jacobson et al. (2018) in detail. Where technical shortfalls emerge in results, we propose corrective measures to ensure system reliability.

To promote transparency in the energy modelling community, our model is available within Appendix C.

6.2.1 Context

The wind, water and solar (WWS) roadmaps outlined by Jacobson et al. (2018) are extremely ambitious (and extremely controversial) decarbonisation pathways. The proposed WWS roadmap for the United States of America, for example, led to the well-documented controversy between Jacobson et al. (2015) and Clack et al. (2017). In this chapter, the analysis seeks to first identify the relevance of the WWS roadmaps in the context of the European energy system and then to analyse their technical feasibility of its implementation.

This chapter examines the WWS portfolio through the limited lens of power system reliability only. The analysis focuses on frequency balancing, unmet energy and levels of reserve. It does not include a detailed analysis of reactive power, voltage control or transient stability. Nor does it do a complete due diligence on the other concepts, practicalities, cost, etc. that fall outside of the arena of power system reliability, many of which have been raised and discussed in Clack et al. (2017).

From a high level, major concerns exist regarding various aspects of the WWS roadmaps. For instance, electrification of nearly the entire energy sector is central to the roadmaps. This key assumption is highly questionable when one considers the litany of industrial processes and modes of transportation that may not be suited to electrification. Regarding energy demand, the WWS roadmaps also assume a decrease in overall energy requirements between today and those of 2050, which Jacobson et al. (2015) explained is achieved through energy efficiencies, especially process efficiencies such as mining, oil and gas exploration/refining, etc. The WWS roadmaps also assume that up to 75% of demand is flexible over several hours or days, depending on the specific demand type (mainly transportation and high-temperature industrial processes). Compared to current levels of demand flexibility, which is extremely limited, this is highly ambitious and untested. Another compelling assumption is that all thermal-based generation capacity (with or without carbon capture and storage) such as nuclear, bioenergy, coal, waste, natural gas-fired generation is excluded citing air pollution health and climate concerns, nuclear weapon proliferation risks, issues with toxic waste and finally, construction delays. The WWS roadmaps also assume thermal storage capacities in the form of extremely large district heating networks may be used to store excess electricity in the form of thermal energy which can be used months later to fulfil heating requirements. For a full breakdown of the WWS roadmaps, see the Supporting Information from (Jacobson et al., 2018).

6.2.2 Approach

We replicate modelling of the European region as outlined by Jacobson et al. (2018). Containing 40 countries (the EU-27 and neighbours), we simulate the full energy system (power and thermal – generation, storage and demand) for 1 year at 5-minute resolution using PLEXOS® Integrated Energy Modelling software (Energy Exemplar). This approach is different to that of Jacobson et al. (2018) who estimate the variable generation capacity required to match annually averaged electricity and thermal demands, ignoring detailed analysis over shorter timescales. We incorporate 30 years of weather variability into the generation profiles through a multi-sample modelling approach previously employed by Collins et al. (2018) to understand impacts of wind and solar inter-annual variation and weather extremes[2]. Where

[2] The multi-sample approach was not considered for demand profiles due to the proposed scale of demand flexibility. For example, Fig. 6.1 demonstrates that up to 75% of system demand is flexibility across several

corrective actions to the original WWS portfolios are required for system reliability reasons, the capacity expansion function in PLEXOS® is employed using technical and economic characteristics. This approach also includes reserve requirements for the power system, see Section 6.3.4. Further information on the methodology, model structure, data, et cetera, is available in the proceeding Methods section (6.5) and Appendix C.

6.2.3 WWS scenarios

The scenarios, or 'cases' as labelled by Jacobson et al. (2018), contain three alternative approaches to decarbonise the entire energy system. The primary commonalities across the cases are three-fold; extremely high levels of VRE capacity, storage capacities much greater today's values and lastly, significant elasticity in demand, as demonstrated in Figure 6.1. The chief differentiating factors between the cases are:

- **Case A** assumes large stationary battery capacity (1000 GW) (up from approximately 1 GW today (Schmidt et al., 2019));
- **Case B** assumes peak hydro discharge rates increase by a factor of 4;
- **Case C** assumes thermal demand is mainly fulfilled using heat pumps (up from approximately 6% share today (European Heat Pump Association, 2018)).

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hours/days depending on the specific type of demand. Therefore, it was decided that any demand profile applied only represents a faction of demand and only serves a starting point for demand to be shifted around.

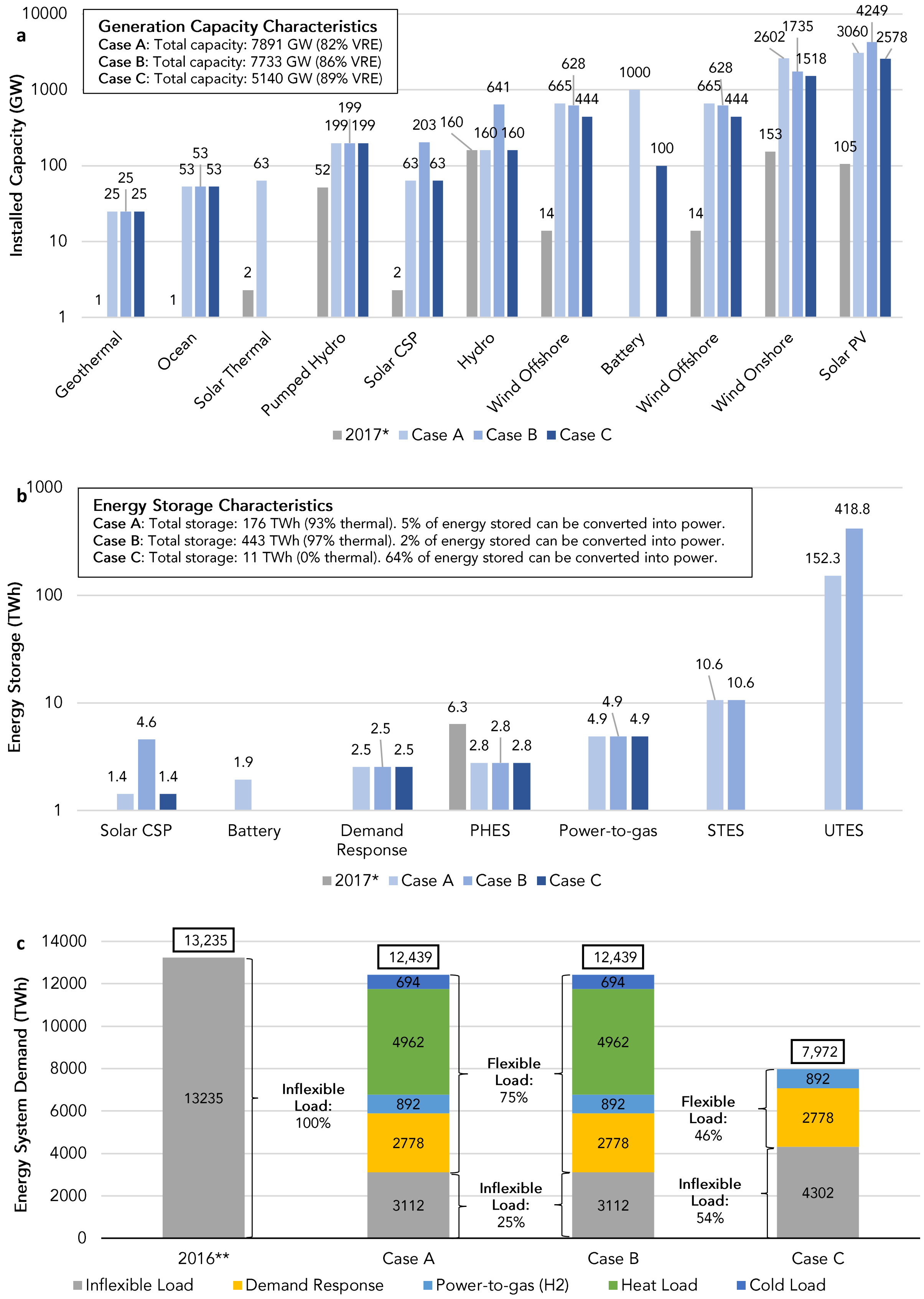


Figure 6.1: Overview of the WWS portfolios. a) Presents a fuel-type view of installed generation capacity. b) Presents energy storage assumptions. c) Illustrates the system demand assumptions. Acronyms: PHES, pumped hydro energy storage; STES, sensible heat thermal energy storage; UTES, underground thermal energy storage.

* Historic data represents the WWS European region excluding Belarus, Moldova, Malta, Ukraine and Kosovo(ENTSO-E, 2018a). ** Gross final energy demand for EU-28 countries only(International Energy Agency, 2018). Data to replicate the WWS cases was acquired from Delucchi et al. (2016) and the Supporting Information(Jacobson et al., 2018).

6.3 Results and discussion

6.3.1 Inter-annual variability

When examined at 5-minute resolution using PLEXOS®, all scenarios proposed by Jacobson et al. (2018) experience energy shortages in the order of 3-17% of demand unmet across the 30 weather years we sample from. Natural weather variation has clear effects on WWS power generation (Figure 6.2). We also establish that the WWS scenarios do not meet system adequacy standards.

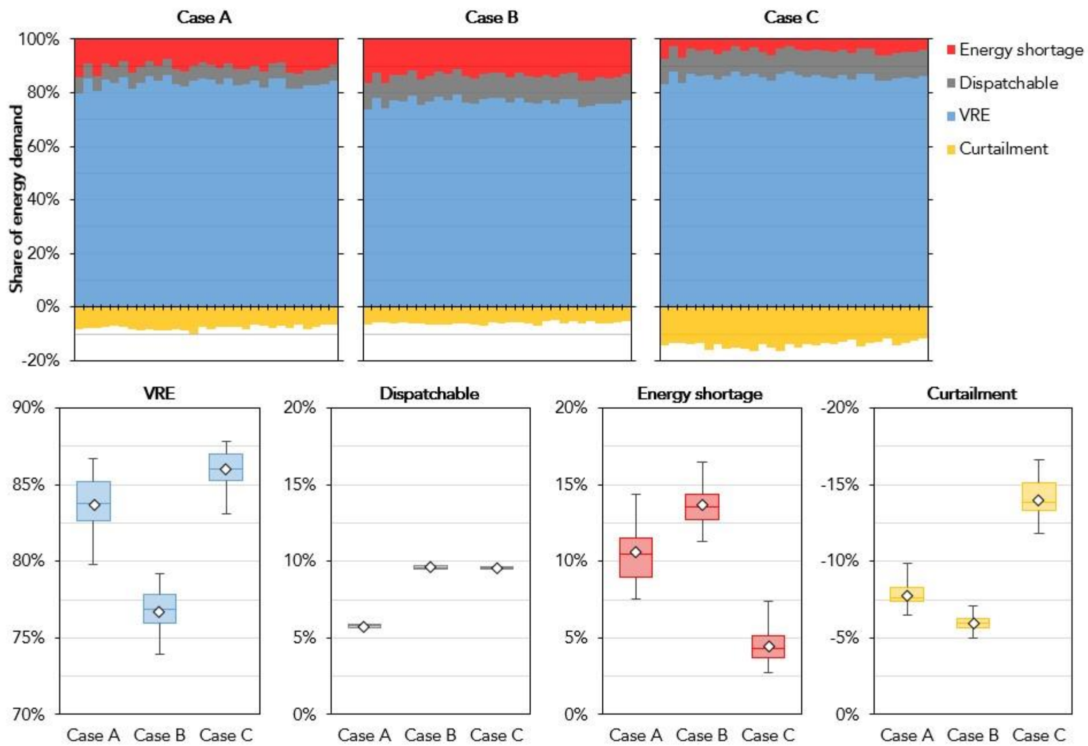


Figure 6.2: High level insights into the WWS energy system scenarios applying a multi-sample modelling approach. Energy shortages are greater than energy curtailments in two of the three scenarios, therefore an energy deficit exists, even if all variable renewable energy (VRE) could be utilised. For the other scenario, Case C, no large-scale energy storage is assumed thereby making it difficult to utilise excess energy generated. VRE generation represents onshore and offshore wind, solar PV, solar thermal, tidal and wave power. Dispatchable generation represents hydro power, geothermal, geoelectric and solar CSP. Seasonal patterns of large thermal storage are included in Appendix C to demonstrate the role of diurnal storage.

For the most part, our assumptions are taken directly from the WWS roadmaps, as demonstrated in Figure 6.1. Where the approaches differ is with respect to generation profiles. For instance, Jacobson et al. (2018) assume an average capacity factor for hydro power of

45.2%, as do we. However, our approach applies a historic monthly profile to the hydro generation which is representative of actual conditions rather than using an annualised capacity factor constraint that may not be realistic in terms of energy inflow from climatic-dependent conditions such as melting ice or seasonal rainfall, see Appendix C for a comparison of both approaches. We also apply high temporal resolution generation profiles for wind (onshore and offshore) and solar (PV) based on validated historic data over the last three decades, whereas Jacobson et al. (2018) assume more ambitious capacity factors for the same generation types (Table 6.1). Wind and solar PV represent 88-94% of total generation capacity in the WWS study, therefore capacity factor deviations of the magnitude shown in Table 6.1 enviably result in large differences in overall energy production. To compensate for the lower capacity factors applied in this analysis, we expand generation capacities in the next section. However, the variances between the different results may also be associated with the differing methodological approaches undertaken, i.e. we employ a full unit commitment model matching supply and demand at high temporal resolution – a fundamental requirement of power systems.

Table 6.1: Comparing the average annual capacity factor assumptions used for both WWS and our approach along with utilised results. The European average capacity factors for solar PV and onshore wind represent the long-term future planned fleet of farms but are one-third lower than those assumed in the WWS scenarios. For the 'utilised (after curtailment)' capacity factors, we use the mean of the 30 samples applied to wind and solar PV generation. Curtailment reduces the 'net' capacity factor of solar PV and wind by a further 4–6%.

Technology	WWS Assumptions	Our Assumptions	Utilised (after curtailment)
Geothermal Elec	81.6%	81.6%	81.1%
Geothermal Heat	97.3%	97.3%	91.0%
Hydro	45.2%	45.2%	45.2%
Tidal	22.4%	22.4%	21.4%
Wave	19.5%	23.9%	23.1%
Solar PV	18.9%	12.9%	12.1%
Solar CSP	49.5%	49.5%	37.3%
Solar Thermal	7.2%	7.3%	6.9%
Wind Onshore	35.0%	23.2%	22.4%
Wind Offshore	36.3%	32.3%	31.1%

6.3.2 WWS scenarios modified to achieve today's reliability levels

Electricity plays a fundamental role in modern-day society (Armstrong et al., 2016) and even more so in WWS proposals for 2050. We propose corrective measures to Jacobson et al.'s scenarios to bring them in line with today's adequacy standards, considering the most difficult year for wind and solar power generation over the past three decades, 2010. The approach used in this chapter aligns with the ENTSO-E's Mid-term Adequacy Forecast 2017 (ENTSO-E, 2017a) in that we consider the maximum acceptance level of power shortages, also known as unserved energy, for the entire European region to be 0.004% of total annual power demand (see Appendix C for more details). This standard aligns with that of other international systems such as the PJM network in the United States and the Australian National Electricity Market (Čepin, 2011), and is approximately 4000 times lower than found in Figure 6.2.

We propose two alternative corrective measures for each scenario. The first aligns with the views of the WWS scenarios (Jacobson et al., 2018) and is based around increasing VRE generation capacity. The second contrasts with Jacobson et al. (2018) and introduces new dispatchable generation capacity which, as shown in Figure 6.3, may provide positive cost benefits. The latter is included as an alternative to increasing VRE capacities beyond magnitudes already considered high, and thus further increasing reliance on a small number of generating technologies (Clack et al., 2017). Augmenting storage capacity is not considered as it would have no effect on increasing overall power generation because as Figure 6.2 demonstrates, energy shortages are greater than energy curtailments in two of the three scenarios. Therefore, an energy deficit will still exist even if all curtailed energy could be utilised. For the other scenario, Case C, no large-scale energy storage is assumed thereby making it near impossible to utilise excess energy generated. Figure 6.3 gives context around the scale of generation capacity supplementation required for either VRE or dispatchable capacity to attain system adequacy standards in each case.

Regarding new dispatchable capacity, we propose that high efficiency combined cycle gas turbine technology be the technology of choice as it is a mature technology (eliminating technological development risk), has the ability to ramp generation output quickly (improving operational flexibility) and consumes natural gas which can be substituted with synthetic gas created using excess/curtailed energy, as discussed by Child et al. (2019). Synthetic gas, or more accurately referred to as 'e-gas', may provide the energy storage medium the WWS scenarios appear to lack, i.e. the ability to convert stored energy back into electricity[3]. Zappa et al. (2019) and Sepulveda et al. (2018) support this proposal regarding dispatchable power

[3] It is acknowledged that other forms of synthetic gases may be better positioned to fuel dispatchable power. For example, biomethane has a higher technology readiness level and lower cost than hydrogen. Biomethane also represents 20% of Denmark's gas grid while Ireland has a target of 33% biomethane followed by 17% hydrogen in their gas grid by 2050. However, as this chapter is seeking to replicate the WWS roadmaps, the decision was taken to align as closely as possible with the roadmaps which already assume power to gas technology is commercially available.

and its importance for maintaining current levels of system adequacy, albeit only considering the power sector rather than the entire energy sector as done here. Sepulveda et al. (2018) suggests that dispatchable capacity can half electricity costs in fully decarbonised scenarios.

In terms of energy system decarbonisation, Figure 6.3 shows the consequence of choosing one corrective measure over the other. Electing to install dispatchable capacity over VRE means the sector remains at least 83% renewable and potentially 84-95% carbon neutral (if operating on e-gas) while costing 13-34% less. As such, achieving the cost-optimal carbon neutral energy system in this analysis is dependent on the availability of excess, curtailable energy. Next, we combine the corrective measures to calculate an optimal blend of each corrective measure for complete energy sector decarbonisation.

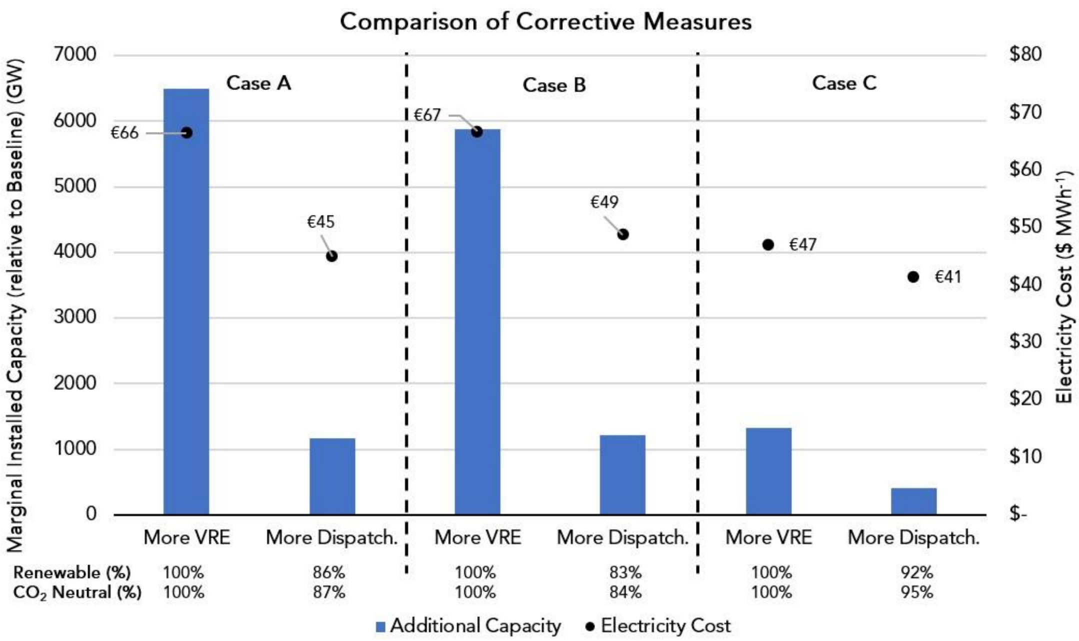


Figure 6.3: Additional power generation capacities associated with alternative corrective measures for each scenario to attain adequacy standards. Compares the additional newly installed capacity of two alternative corrective measures required to reduce unserved energy to within adequacy standards, along with the incremental cost of each option. We assume new dispatchable power is 60% efficient and consumes natural gas or e-gas when available at a cost of \$27 GJ^{-1}. The total power system costs associated with each measure is demonstrated as an incremental cost per unit of delivered electricity and does not include costs related to demand side participation, i.e. representative of a supply-side cost, see Supplementary Information for more details. E-gas may be considered renewable; however, debate is ongoing. Total power system costs are annualised, undiscounted costs (i.e. no interest rates applied) where the capital expenditure is spread over the technical lifetime of the technology with variable costs also included, see Appendix C for more details.

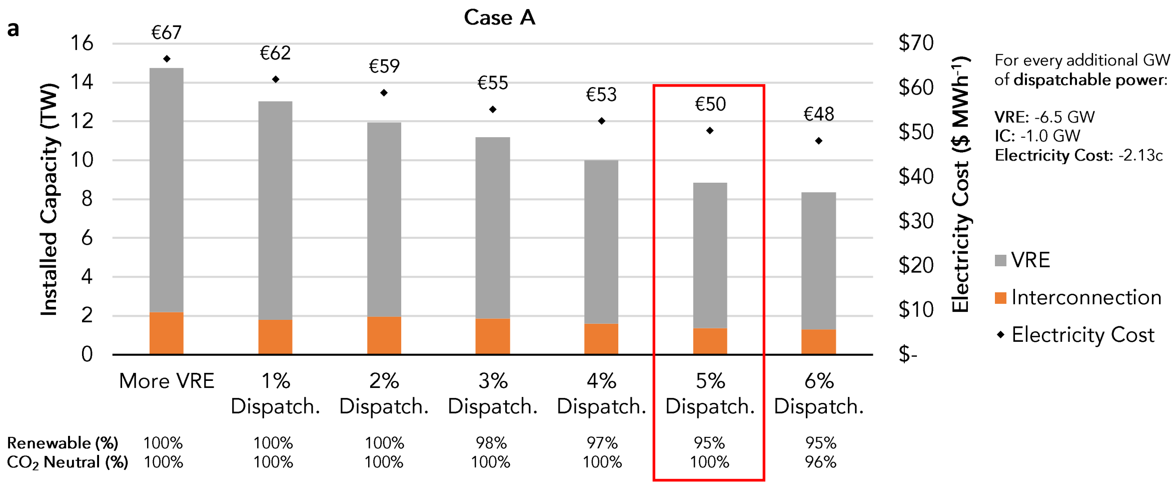
6.3.3 System reliability using carbon neutral generation

While the counterfactual is assumed to be the 'More VRE' corrective measure, in alignment with the 100% WWS vision, dispatchable capacity is incrementally introduced to achieve a carbon neutral energy system. In all cases, we find that carbon neutrality can be attained with

5% or less dispatchable capacity which is fuelled by e-gas converted from excess, otherwise curtailed, electricity. From the figure, the red rectangle highlights the cost-optimal yet carbon neutral variant in each case. Further percentage-sized incremental increases in each case result in the system not achieving carbon neutrality due to e-gas scarcities. The figure also demonstrates that capacity requirements and power system costs all improve with incremental additions of dispatchable generation. These have simple linear relationships over the range shown, allowing the results to be interpolated, or potentially extrapolated to higher shares of dispatchable generation.

As shown in the legends of Figure 6.4(a-c), 1 GW of dispatchable generation can displace 2.8-6.5 GW of VRE capacity and 1-1.5 GW of transmission capacity across the WWS scenarios. 50 GW of dispatchable generation lowers the continent-average power price by approximately \$1 MWh^{-1}. There clearly exists a trade-off between cost-efficiency and the desire to achieve near-100% renewable share.

Irrespective of how the unserved energy is resolved or what level of decarbonisation is achieved, further questions and significant challenges regarding the operability of these WWS-based systems remain, to which we turn next.



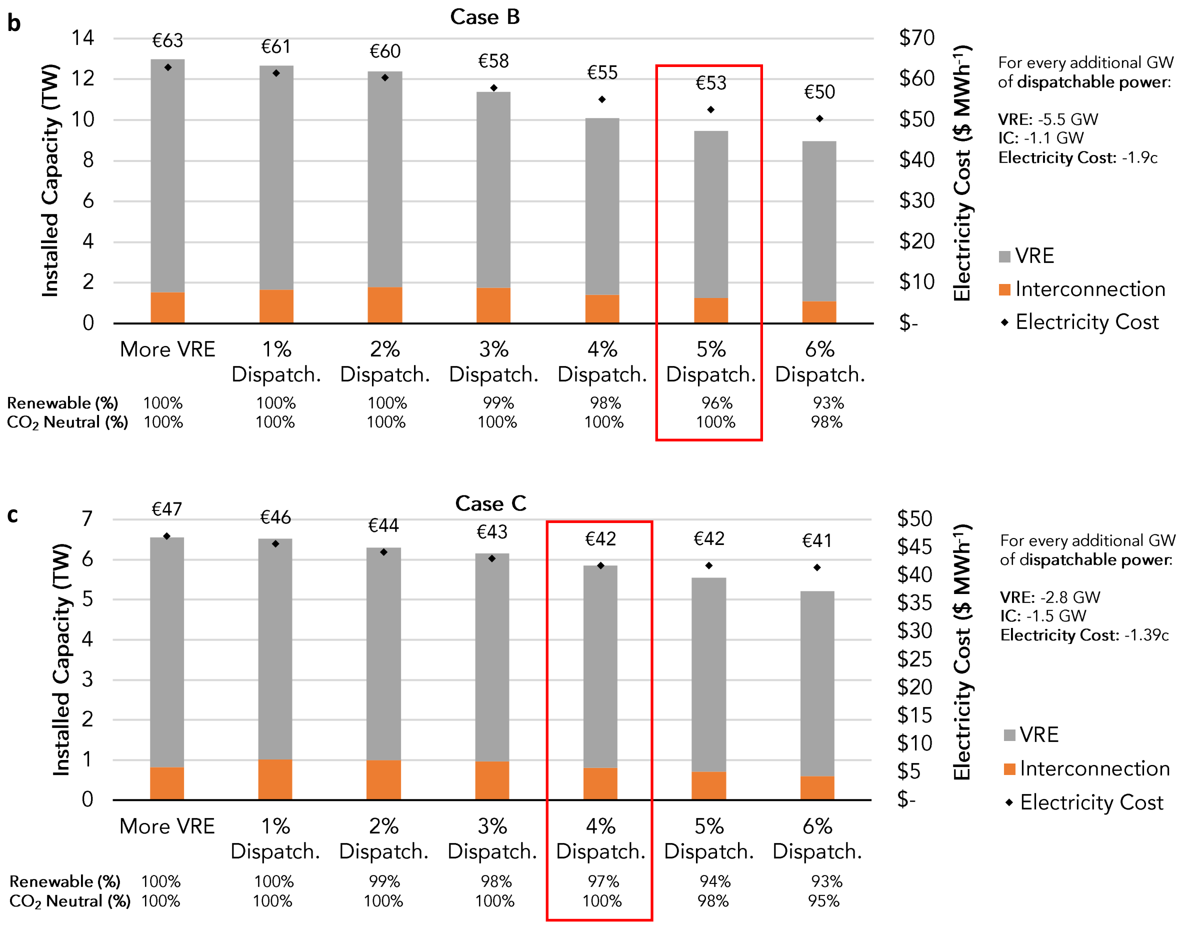


Figure 6.4: Incrementally increasing the level of dispatchable capacity in the More VRE corrective measure. The legend included in (a-c) represents the relationship between each additional GW of dispatchable power and transmission/VRE/electricity cost. Each percent of dispatchable power in Cases A-C equates to approximately 130 GW, 125 GW, 60 GW respectively. Electricity used to create e-gas is assumed excess to both generation and reserve requirements.

6.3.4 System stability of the WWS roadmaps

Once a power imbalance occurs reserves are activated to contain and then restore frequency. In this chapter, these are referred to as containment and restorative reserves respectively. Literature suggests that reserve requirements may increase in accordance with the level of VRE installed in a system (Brouwer et al., 2014; Holttinen et al., 2008; Papavasiliou et al., 2011). Brouwer et al. (2014) for example, estimates that secondary, tertiary and replacement reserves may increase by 7% of installed wind capacity. Here, we apply a published methodological approach by Holttinen et al. (2008) to estimate the increased operational reserve requirements for the restorative reserve using 3.5 standard deviations (99.9 percentile) (Dvorkin et al., 2015) which results in a dynamic reserve equal to 6.8% of generating VRE. When modelled, this dynamic reserve is held in parallel with the containment reserve requirements in continental Europe, i.e. 3 GW.

Figure 6.5 shows that traditional providers of reserve (hydro, PHES, other dispatchable capacity) can represent less than half of the annual requirement with de-loaded VRE capacity providing the remainder. ‘De-loading’ is the process of reducing a unit’s output below maximum potential in a given period to provide the ‘headroom’ needed for upward reserve (Ela et al., 2014; Fleming et al., 2016). VRE reserve strategies, such as de-loading, reveal several potential issues regarding policy, economics, operations, etc., none of which are addressed in further detail. As with its energy production, there is an inherent variability and uncertainty (forecast error) with VRE reserve provision. From a risk exposure perspective, Figure 6.5 establishes a positive impact from introducing minimal dispatchable capacity as other traditional reserve providers increase their provision share.

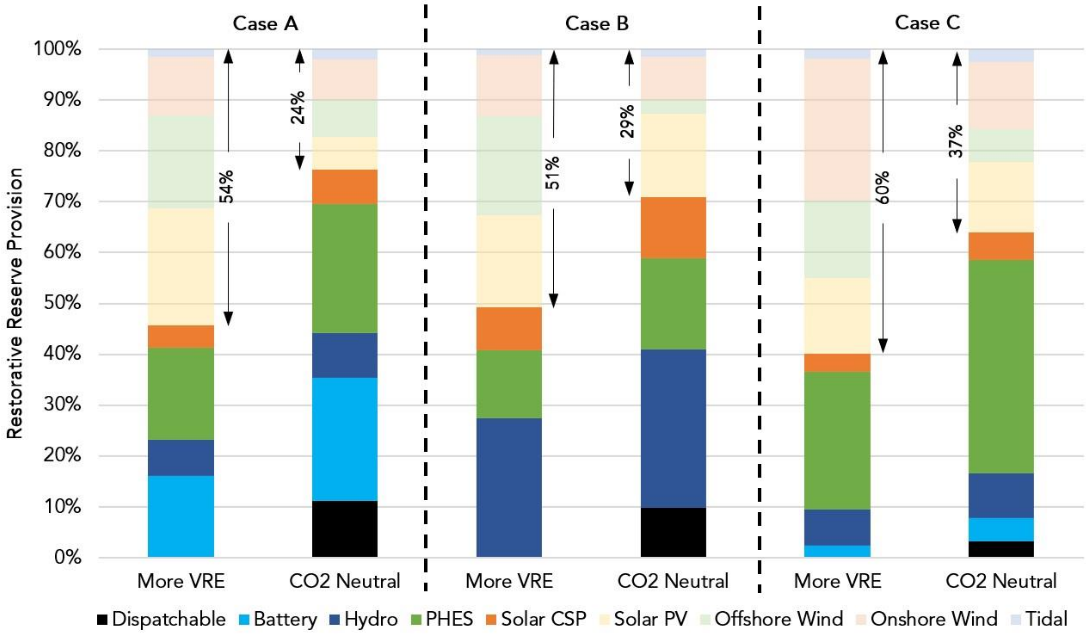


Figure 6.5: Annual restorative reserve provision shares by technology for continental Europe. Reserve provision is shown for upward only.

6.3.5 Reliance on cross-border transmission capacity expansion

This analysis finds that cross-border transmission capacity expansion is an integral part of creating a reliable 100% renewable energy system, agreeing with Green et al. (2016). While transmission capacity assumptions are not specified in the source material, it is assumed that if congestion is an issue increasing transmission capacity would only result in a modest increase in cost (Jacobson et al., 2018). We find that compared to 2017-levels (60 GW), the WWS European region transmission network capacity needs to be approximately 13-36 times higher. When compared to projected 2040 transmission network capacities by ENTSO-E (173 GW), the grid would still need to be 5-13 times more heavily connected, as shown in Figure 6.6. The feasibility of commissioning these levels of transmission capacity may prove difficult, as discussed (Fürsch et al., 2013; Green et al., 2016; Nasirov et al., 2015; Spiecker et al., 2013). However, it is clear from Figure 6.6 that introducing dispatchable capacity can reduce reliance on transmission capacity and therefore reduce the associated risk exposure. In summary, we find that capacity requirements, system costs and ancillary services all improve with incremental additions of dispatchable generation.

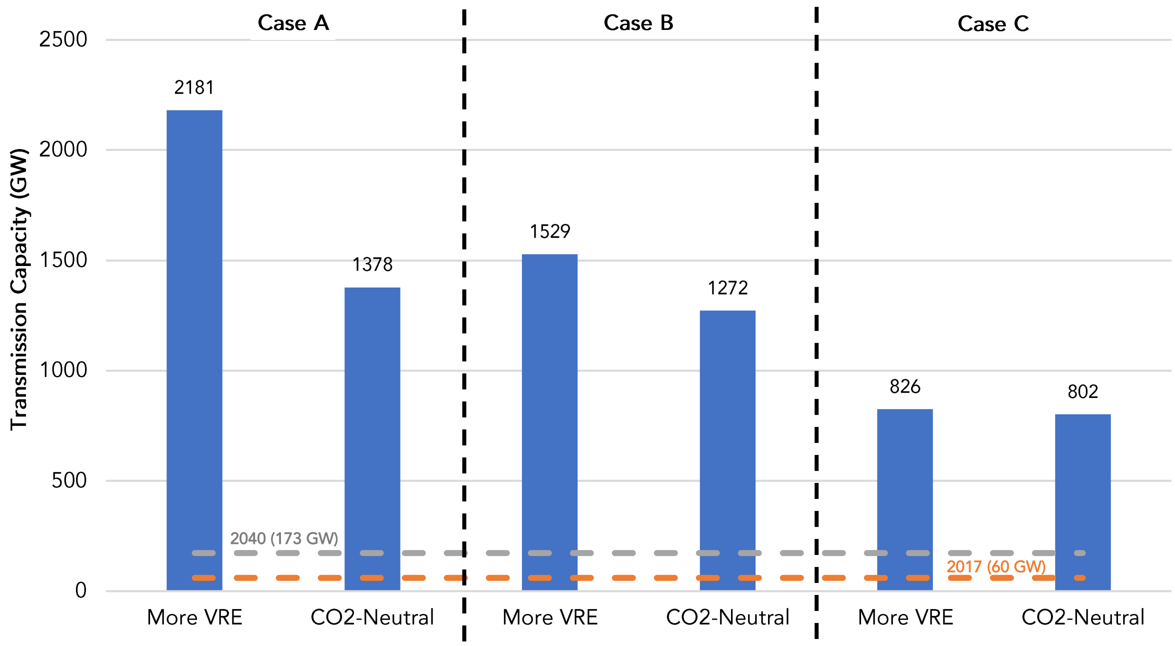


Figure 6.6: Estimated transmission capacities for each WWS scenario including corrective measures. Projected 2040 transmission capacity is taken from the ENTSO-E 2040 publication applying the 'Distributed Generation' scenario assumptions (ENTSO-E, 2018b).

6.4 Conclusion

This chapter highlights several areas of concern surrounding the reliability of ambitious energy systems like those of the WWS proposals. While the WWS approach aims to reduce any over-reliance on technological development, we find that the implicit reliance on power electronics to replace the system dynamics automatically provided by conventional generation could be viewed as such. Achieving a reliable energy system is essential. The continued existence of dispatchable generation capacity is likely beneficial to ensure a smooth transition in the short term. In the long term, various technological options are likely to come online to replace this dispatchable capacity.

The original WWS portfolios come to within 25% of sufficient generation capacity to meet modern-day system adequacy standards in the most difficult year for VRE generation. Whether additional energy storage, VRE, dispatchable capacity or alternative technology is chosen, the decision should be taken with a holistic view of an operational 100% renewable system. To create a reliable and resilient power system, having a diverse mix of sources providing adequacy, flexibility and stability is a key consideration. Increasing VRE capacity does not change system flexibility in terms of controllable response unless it is operated in a non-optimal way, such as de-loading, while the point made for energy storage is equally valid for VRE regarding system stability and the reliance on technological development. This analysis suggests that introducing 5% dispatchable generation improves all aspects of system reliability, lowers VRE and transmission capacity requirements and reduces system costs by 25%, all the while fuelled by carbon neutral means.

The main concerns highlighted as part of this analysis involve ensuring system adequacy and establishing ancillary service strategies in a future system with high levels of VRE and low levels of dispatchable capacity. However, other apprehensions exist such as the feasibility of cross-border transmission capacities outlined herein, the technical experience of operating power systems at such low kinetic energy levels, reliance on larger seasonal thermal energy to name a few. Whether dispatchable power is introduced or not, the challenge largely remains the same. It is worth emphasizing that these concerns highlighted in this analysis relate to one aspect only transitioning to a WWS only energy system, The goal of WWS is laudable, but the IPCC envisage only 70-85% renewable energy (IPCC, 2018), and we suspect that such an ambition (below 100%) will confer many benefits, easing the decarbonisation of energy for operators and reducing the cost for consumers, thus reducing two potentially significant barriers to the wholesale transformation that is required. This study highlights the complex nature of electricity systems, and the critical need for such complexity to not be glossed over.

6.5 Methods

6.5.1 Modelling technique

This research uses PLEXOS® Integrated Energy Modelling software (Energy Exemplar) (PLEXOS®), a unit commitment and economic dispatch modelling tool that cost optimises the technical operation of a power system subject to technical constraints. PLEXOS® is an industry standard mixed-integer linear programming model that has been used for a multitude of studies such as renewable energy integration, techno-economic feasibility studies, system adequacy analysis and capacity expansion planning by global powerhouses in the industry including the

PJM market, the Chilean independent system operator, the Australian energy market operator and the European Network of Transmission System Operators. In this article, the model considers technical characteristics associated with thermal power generation capacity, such as ramp rates, minimum generation levels and max capacities, while creating an optimised dispatch of thermal, renewable and storage capacity. The analysis also incorporates ancillary service requirements for Europe into the simulations, further details outlined in Section 6.3.4 and Appendix C. We simulate the entire system at high temporal granularity (5-minute) to allow more of the technical characteristics of electricity systems operation to be captured in the model, along with their associated additional costs (Deane et al., 2014).

The PLEXOS® model is configured to simulate over a three-year period, one year before and one year post-2050, at 5-minute temporal resolution. This approach was taken on account of the magnitude of thermal energy storage. There are two stages to our modelling technique which seeks to best utilise the large energy stores. **Stage 1)** the entire three-year period is dispatched in one step at daily temporal resolution. This maximises the utilisation of the large energy storage capacities though its extended time horizon, i.e. storing energy in one season for later use in another. This approach effectively replicates the look-ahead function in PLEXOS® which, as the name suggests, looks ahead. What I do using this approach is use a very large horizon to dispatch in one step so therefore, large energy storage capacities can be utilised more efficiently. Capacity expansion decisions are also made at this stage if deemed necessary. **Stage 2)** takes energy storage end volumes and capacity expansion decisions from the stage 1 and simulates a 5-minute simulation to create a high temporal resolution set of results. This approach improves the utilisation of large seasonal energy stores which, otherwise, are wasted. This approach replicates a more optimised, better planned energy system.

Within the model, each country is represented as a region containing two nodes; electricity and thermal. Both nodal types have their own stores, generation and demand. For example, each thermal node has solar-thermal generation with short term energy storage (STES) and underground thermal energy storage (UTES) to meet heating/cooling loads. As with the approach taken in Jacobson et al. (2018), we assume electricity can be used to meet thermal demand but not vice versa. A one-way link between the nodes is used to replicate energy conversion via dielectic heaters, electric furnaces, et cetera (Jacobson et al., 2017).

Flexible demands are implemented in two parts; the demand and the flexibility. Demand profiles are described in the source material and therefore are replicated. These are introduced via the purchaser class and assumed inflexible. The associated flexibility is introduced via the storage class. For example, power-to-gas is assumed to have two-days' worth of hydrogen storage in Europe. This is implemented using head and tail reservoirs sized to the previously stated hydrogen volume linked to specific generators. These stores include constraints that ensure a minimum and/or maximum level of generation is achieved to align with the source material assumptions around flexibility. Similarly, thermal loads are implemented via the purchaser class and are inflexible. Flexibility is incorporated into these thermal loads through the Underground Thermal Energy Storage capacities.

Where system adequacy standards are not met, the portfolios are supplemented with increased levels of generation and interconnection capacity using a long-term capacity expansion optimisation module built into PLEXOS®. Based on technology costs presented in Appendix C the long-term capacity expansion determines the least-cost portfolio that achieves the necessary reliability standards. For further details on the implementation of the long-term expansion, see Appendix C. While we assume CCGT technology as the dispatchable capacity of choice in this article, other forms of dispatchable capacity such as nuclear, bioenergy or carbon capture and storage technologies exist but were not considered for several reasons. For example; nuclear can result in weapons proliferation risk, waste, and delays, while carbon capture and storage technologies are currently not in commercial use for power generation and therefore, inherently include a technological risk and reliance on further development.

Chapter 7: Conclusion

In this thesis, evolutionary pathways for the European power system driven by climate mitigation policies are analysed. Experiences of past and present transformations of the energy marketplace are distilled into clear and concise learnings. Considerations for future decarbonised power systems are discussed from a policy, regulation, economics and system operation perspective. Globally, policymakers and society are confronted by important decisions regarding the balance between cost equality, economic growth, energy security and climate action. This chapter concludes the thesis with a summary of insights gained. Initially, focusing on a national perspective in the past and present where the various learnings and strategies in place for an island system to remain fit-for-purpose are outlined. This followed by the focus switching to a future supranational perspective where system adequacy and overall reliability become the main focus of attaining an operable 100% renewable energy system.

The original aim of the thesis was to analyse evolutionary pathways for the European power system resulting from climate mitigation policies. This was broken down into five research questions initially posed by this thesis in section 1.2 and restated below. Chapters 2-6 in this thesis have set out to achieve at least one of these research questions.

1. How the electricity sector in Ireland evolved over the past century and what were the key learnings in the future?
2. How can power sector decarbonisation ambitions be reconciled with market economics and system operations?
3. Can coordinated European policy support schemes for renewable energies lead to more equitable and optimal power sector decarbonisation?
4. Should Europe aim for a negative emissions power system over a high renewable alternative?
5. Can a 100% renewable energy system be operationally resilient in Europe when based on wind, water and sunlight alone?

7.1 Marketplace Evolution

A central focus of the thesis has been the persistent focus on evolution. Beginning with Chapter 2 in 1916 where changes in electricity sector policy over the following century are reviewed, through to Chapter 6 where potential scenarios for reliable 100% carbon neutral energy systems are analysed on a European scale.

Chapter 2 examined the struggles of a small electrically isolated electricity system to overcome security of supply concerns, geo-political unrest, poor policy decisions and the various energy crises to establish the first dual-currency electricity market in the world. Lack of energy policy caused great consternation when alerts by the national monopoly were ignored around over-reliance on certain fuels, namely hydro and peat in the 1950's then oil in the 1960's, leading to large exposures to subsequent climatic and geo-political events in what exemplifies the reactive nature of Ireland's energy policy at the time. The chapter highlights the importance of key decisions regarding the future of the sector when the ESB, the national monopoly, turned down the option of selling electricity in bulk to other distributors, instead opting to deliver electricity directly to consumers to reduce the effects of local politics and municipal boundaries on the development of a national electricity network. The examination identified the breakpoint in time when electricity policy became focused and a clear impetus was put on energy-related policy moving forward. The deployment and integration of large-scale wind power in Ireland resulting from strong national and supranational policy decisions is a prime example. Subsequently, Ireland's electricity system has become a world-leader in the facilitation of variable renewable energy on a single synchronous power system, which leads into Chapter 3.

Investigating the challenges in reconciling ambitions for variable renewable integration with market economics and system operation using Ireland's electricity sector as a case study was discussed in Chapter 3. The case study highlights the strategies implemented to optimally balance efficiency, flexibility and adequacy while maintaining a fully functional system that strives to adapt to evolving conditions. This chapter presents real life challenges faced by a small isolated island system that could be considered a precursor to events/challenges awaiting a wide range of global electricity systems. We demonstrate how transforming the energy market, capacity mechanism and system service arrangements was instrumental in transitioning away from a previously cost-based market to a value-based alternative that rewarded flexible and reliable capacity with the ability to evolve with market conditions of the future. Future-proofing the market was the primary goal – one that appears particularly relevant at present considering the reality that most are not fit-for-purpose in the changing marketplace driven by climate mitigation policy.

In what has been described as a ‘liberalised market on training wheels’, the analysis also identified how market participants before the market overhaul were shielded from financial risk through several mechanisms ensuring full cost-recovery and thereby not considered dynamic in their approach to normal market conditions, i.e. price signals did not always attain the required response. These circumstances resulted in a lack of competition and capacity mechanisms were required to entice investment. Post-market restructuring; the three primary revenue streams are geared towards securing the necessary generation capacity moving forward into a future power system that is, in many ways, dictated by the current focus on climate action.

With a view to future European energy systems, Chapters 4, 5 & 6 are supported by emerging literature highlighting the essential role decarbonised electricity generation will play in future energy systems consistent with the Paris climate agreement. In Chapter 5 for example, the analysis compares the impacts of high levels of renewable electricity and negative emissions technologies on exploratory visions of the future EU power system in 2050 in terms of emissions reduction, technical operation and total system costs. The analysis shows that a Negative Emissions scenario bound by regional biomass potentials and national CO_2 storage potentials can achieve a power system-wide CO_2 intensity reduction relative to the baseline scenario while remaining cost-comparable. Furthermore, the analysis estimates that converting just 2% of the EU’s installed generation capacity to BECCS consumes 69% of the projected available sustainable biomass while enabling the power system to achieve net-negative emissions (-7.5 $kgCO_2\ MWh^{-1}$).

In Chapter 6 the focus changes to entire energy system decarbonisation across Europe. The technical feasibility and economic viability of a 100% renewable Europe is examined while assessing the ability of the system to maintain stable power system operation with regards to system adequacy, system flexibility and system stability, basing our results on a replication and extension of extremely ambitious studies using a detailed and fully open European power system model. The analysis shows that while the original scenarios do not comply with modern-day system adequacy standards, the decision associated with system expansion should be taken with a holistic view of an operational 100% renewable system. To create a reliable and resilient power system, having a diverse mix of sources providing adequacy, flexibility and stability is a key consideration.

However, technology readiness and the associated risk exposure play a definitive role in results of Chapter 5 & 6. In terms of system decarbonisation, Chapter 5 demonstrates that the state of readiness for carbon capture and storage (CCS) technology dictates whether the High VRE or Negative Emissions scenario achieves the lowest system-wide CO_2 intensity. Chapter 6 identified concerns around over-reliance on power electronics to create an entire energy system resilient to energy shortfalls/scarcities which is primarily powered by variable generation. Moreover, the analysis shows that risk exposures can be reduced by re-introducing existing, mature technologies, such as combined cycle gas turbines in the case of Chapter 6. For example, introducing 5% dispatchable generation improves all aspects of system reliability, lowers VRE and transmission capacity requirements and reduces system costs by 25%, all the while fuelled by carbon neutral means. Major technology risk is also present regarding CCS technology with questions over commercial readiness and scalability; operational risk where high concentrations of variable generation diminish generator capacity factors; market participant risk with market prices reducing due to the overall shift in the cost of energy from operational costs to capital costs and finally; consumer risk with incremental electricity costs varying widely and therefore run the risk of heightening budgeting concerns for the consumer.

7.2 Policy

History shows that policy must continually adapt to maintain balance between market competitiveness, system security and consumer protection all the while implementing national or international objectives such as climate mitigation policy. In this thesis, policy is instrumental throughout each chapter. The learnings from delayed, reactive policy decisions discussed in Chapter 2, which sparked a defined energy policy focus in Ireland post-1970's, to concentrated and clear policy measures outlined in Chapter 3 where reconciling ambitions for variable renewable integration with market economics and system operation were addressed, is but one example.

In Chapter 4 where the quantification of renewable electricity (RES-E) shares on a country-by-country basis is discussed, policy is a central theme as climate mitigation plans push up against market dynamics, potentially resulting in cost inequalities that expose the European consumer. Questions around whether RES-E shares should be measured based on consumption rather than production are important to analyse considering the likely part to play by variable RES-E generation-interconnection nexus in future decarbonised power systems. The chapter recognizes that the primary concern is being caused by increasing interconnection capacity which exacerbates an underlying issue with price distortions stemming from out-of-market financial support schemes that decrease wholesale market prices. Moreover, the analysis singles out a paradox: "as renewable generation (receiving out-of-market support) increases, wholesale electricity prices decrease, becoming more attractive to export at a price that is *not* truly reflective of the cost to generate that power." Consequently, the analysis shows that price distortions create cost inequalities as consumers are left to remunerate the renewable electricity producer while the energy is consumed out of state. The proposed 'consumption-based quantification' policy would correct this cross-border subsidisation of RES-E, enabling more equitable and optimal electricity decarbonisation – effectively socialising the cost of renewable electricity across state boundaries to improve cost equalities during the transition to a decarbonised system. Increasing the accuracy of cost distributions associated with the consumption of renewable electricity would also provide secondary gains. Aside from reducing the level of revenue required to remunerate RES-E generation in an exporting country, this approach would lower the economic barriers surrounding the cost to consumers of developing higher levels of RES-E capacity.

The importance of policy is also evident in Chapters 5 & 6. To achieve a decarbonised power, or entire energy, system for Europe, policy direction is essential. The main objective of the analysis outlined in Chapters 5 & 6 is to provide robust analysis for policy makers to make an informed decision applying highly transparent and reproduceable methodological approaches. In Chapter 5 we show that technological readiness and risk exposure go 'hand-in-hand' with policies heavily dependent upon un-tested technologies. The analysis quantifies this reliance on negative emission technologies (NETs) in terms of decarbonisation levels achieved versus the potential for Europe in a 2050 setting to add additional emphasise the overall message. Reliance on NETs may help to achieve a negative emissions status, however, delayed or lack of technological progression could leave the system in a worse off place than alternate pathways from a decarbonisation point of view. It is unlikely there is a silver bullet to undo decades of climate inaction, therefore learnings from Chapter 2 tell us that policy makers must not over-rely on a small number of options to achieve their goals.

In a similar vein, Chapter 6 highlights several areas of concern surrounding the reliability of ambitious energy systems when relying on variable sources of energy for near-100% of energy demand. From a policy decision making perspective, alternative measures may offer greater security both in terms of risk and reliability exposures, however these alternates may require a broadening of focus, i.e. taking a holistic view. The ambitious 100% renewable energy system scenarios replicated in Chapter 6 for example, rely on variable electricity generation for most of their energy required. These scenarios also assume hydrogen is created via power-to-gas (PtG) for transportation purposes. Our analysis identifies an alternative approach that takes the same assumption (that PtG will be technological feasible) and creates e-gas which is carbon neutral (some might say, renewable) and a form of energy storage with a vast distribution network via the existing grid infrastructure. This e-gas is then used to power dispatchable power generation which improves all aspects of system reliability, lowers VRE and transmission capacity requirements and reduces system costs. Therefore, taking the same goal, we propose an alternative that relies on the same technological readiness regarding PtG, yet reduces reliance on capacity development, increases system reliability and all at a lower cost. This is an example of an alternative scenario that is made highly transparent and open to reproducibility, critique and hopefully, further development on the pathway to assessing the optimal choice(s) for the situation at hand. Open and reproducible science is key.

7.3 Future Work

This thesis does not present a silver bullet solution to the challenges ahead. Energy sector decarbonisation is perhaps the biggest hurdle ever faced by mankind. Much of the analysis needed, remains unfinished and already too late. To-date, significant questions remain around the best approach for energy system decarbonisation. However, no matter the choice, cost inequalities much be avoided. Protection of the European consumer is essential. As such, real time analysis of cross-border renewable electricity flows could be a future piece of work following on from this thesis.

Chapter 4 outlined a methodological approach for quantifying renewable electricity flows across European member state boundaries, demonstrating the potential scale of the cost inequality issue in a 2030 scenario. In what was described as “food for thought” for policy makers, further work could be the creation of a taskforce to assess the feasibility of accessing real time data from system operators with an ultimate aim of trialling the concept in a testbed environment for a given period. Findings could be presented to national and European policy makers regarding the technical feasibility and economic viability of the project along with insights gained into cost inequality issues with corrective policy recommendations.

Another area requiring further work would be increasing the geographical resolution of European models to zonal or nodal. Hourly simulations at country-level in many ways, only mimics day-ahead market operations. While this represents the majority of power traded in Europe (and globally), it does not account for sub-country level network or system constraints. Real time representation of system operation adds valuable insights from the alternative perspective; that of an operator. For example, the well-documented north-south power flow bottleneck in Germany is not captured in any models used in this thesis. In a similar way, more realistic options for transmission/VRE/storage capacity expansions would strengthen overall results immeasurably. However, this 'wish list' is all data driven. Accessibility is the main barrier. This circles back to a key point made in the introduction; energy research can and must reduce barriers and uncertainties by moving towards highly transparent, reproducible science.

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Appendix A: PLEXOS® Equations

This appendix serves to provide the equations used in PLEXOS®.

Indices

j	Generation Unit
t	Time period.
stor	Index related specifically to pumped storage unit
RES^{up}	Upper Storage Reservoir
RES_{low}	Lower storage Reservoir

Variables

V_{jt}	Integer on/off decision variable for unit j at period t
X_{jt}	Integer on/off decision variable for pumped storage pumping unit j at period t
U_{jt}	Variable that = 1 at period t if unit j has started in previous period else 0
P_{jt}	Power output of unit j (MW)
H_{jt}	Pump load for unit j period t (MW)
W_{int}	Flow into reservoir at time t (MWh)
W_{outt}	Flow out of reservoir at time t (MWh)
W_t	Volume of storage at a time t (MWh)

Parameters

vl	Penalty for loss of load (€/MWh)
vs	Penalty for Reserve not met
use	Unserved Energy (MWh)
usr	Reserve not met (MWh)
D	Demand (MW)
obj	Objective Function
n_{jt}	No load cost unit j in period t (€)
c_{jt}	Start cost unit j in period t (€)
m_{jt}	Production Cost unit j in period t (€)

e_{stor}	Efficiency of pumping unit (%)
$pmax_j$	Max power output of a unit j (MW)
$pmin_j$	Mini stable generation of unit j (MW)
$pmpmax_{stor}$	Max pumping capacity of pumping unit
J_j	Available units in each generator
J_{stor}	Number of pumping units
MRU_j	Maximum ramp up rate (MW/min)
MRD_j	Maximum ramp down rate (MW/min)
MUT_j	Minimum up time (hrs)
A_p	Number of hours a unit must initially be online due to its MUT constraint (hrs)
W_{INT}	Initial Volume of reservoir (GWh)
W	Maximum volume of storage (GWh)

Objective Function:

$$OBJ = Min \sum \sum_{t \in T} c_{jt}.U_{jt} + n_{jt}.V_{jt} + m_{jt}.P_{jt} + vl.use_t + vs.usr_t$$

The objective function in PLEXOS® is to minimise the start-up cost of each unit (start cost (€)* number of starts of a unit) + the no load cost of each online unit + production costs of each online unit + the penalty for unserved load+ the penalty of unserved reserve.

The objective function is minimised within each simulation period. The simulation solution must also satisfy the constraints below:

Energy Balance Equation:

$$\sum \sum_{t \in T} P_{jt} - H_{jt} + use_t = D_t$$

Energy balance equation states that the power output from each unit at each interval minus the pump load from pumped storage units for each interval + unserved energy must equal the demand for power at each interval. (Note that line losses can also be included here but is not shown). As the penalty for unserved energy is high and part of the objective function, the model will generally try to meet demand.

Operation Constraints on Units:

Basic operational constraints that limit the operation and flexibility of units such as maximum generation, minimum stable generation, minimum up/down times and ramp rates.

$$-V_{jt} + U_{jt} \geq -1 \quad \forall t = 1$$

$$V_{jt} - V_{jt+1} + U_{jt+1} \geq 0$$

These two equations define the start definition of each unit and are used to track the on/off status of units.

$$P_{jt} - P\max_j .V_{jt} \leq 0$$

Max Export Capacity: A unit's power output cannot be greater than it maximum export capacity.

$$P_{jt} - P\min_j .V_{jt} \geq 0$$

Minimum Stable Generation: A unit's output must be greater than it minimum stable generation when the unit is online.

$$H_{jt} - Pmp\max_{Stor} .X_{jt} \leq 0$$

Pumping load must be less than maximum pumping capacity for each pumping unit

$$V_{jt} + X_{jt} \leq 1 \quad \text{where } j \in stor$$

$$V_j \leq J_j \quad X_j \leq J_{Stor} \quad j \in J$$

These constraints limit a pumped storage unit from pumping and generating at same time.

$$A_{p,j} \geq V_{j,t} - V_{j,t-1} \forall t..t - MUT_j - 1$$

$$V_{j,t} \geq A_{p,j} - \sum_{t}^{t-MUT_j+1} V_{j,t} / MUT_j \forall t$$

Minimum Up Times[1]: (Note the following text is directly from the PLEXOS Help files). The variable A_p tracks if any starts have occurred on the unit inside the periods preceding *p* with a window equal to MUT. *i.e.* if no starts happen in the last MUT periods then A_p will be zero, but if one (or more) starts have occurred then A_p will equal unity. The MUT constraints then sets a lower bound on the unit commitment that is normally below zero, but when a unit is started, the bound rises above zero until the minimum up time has expired. This fractional lower bound when considered in an integer program forces the unit to stay on for its minimum up time.

$$A_{p,j} \geq V_{j,t-1} - V_{j,t} \forall t..t - MDT_j + 1$$

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[1] PLEXOS Help Files

$$V_{j,t} \leq 1 + \sum_{t}^{t-MDT_j+1} V_{j,t} / MDT_j - A_{p,j} \forall t$$

Minimum Down Times: The variable A_p tracks if any units have been shut down inside the periods preceding p with a window equal to MDT. *i.e.* if no units are shut down in the last MDT periods then A_p will be zero, but if one (or more) shutdown then A_p will equal unity. The MDT constraints then set an upper bound on the unit commitment that is normally above unity, but when a unit is stopped, the bound falls below unity until the minimum down time has expired.

$$P_{jt} - P_{j.t-1} - MRU_j.V_{jt} - p_{\min j}.U_j \leq 0$$

$$p_{\min j}.P_{jt} + P_{jt} - P_{j.t-1} - P_{jt}.(MRD_j - p_{\min j}) \leq 0$$

Maximum Ramp up and down constraints: These constraints limit the change in power output from one time period to another.

Water Balance Equations:

These equations track the passage of water from the lower reservoir to the upper reservoir. In this set-up there is no inflow and water volume are conserved.

$$W_{tR} + W_{out.tR} - W_{in.tR} = W_{INT,R} \quad \forall t = 1, R \in RES_{Up}, RES_{low}$$

$$W_{t.RES^{up}} + W_{out,RES^{up}} - W_{in,RES^{up}} = 0$$

$$e_{stor}.H_{jt.RES^{up}} - W_{in.tRES^{up}} = 0$$

$$P_{stor.t} - W_{out.t.RES^{up}} = 0$$

Appendix B: Supplementary Material – Chapter 5

Country Specific Portfolio Assumptions

Table B1: Portfolio assumptions for Reference scenario (MW)

	Biomass Waste (non-CCS)	Biomass Waste (CCS)	Hydro Lakes	Hydro ROR	Natural Gas (non-CCS)	Natural Gas (CCS)	Nuclear	Oil	Other RES	Solar	Solar CSP	Solids Fired (non-CCS)	Solids Fired (CCS)	Wind Offshore	Wind Onshore	Pumped Hydro Energy Storage	DAC	Power-to-gas	Demand Response
AT	846	0	8700	5330	2850	0	0	0	0	4009	0	0	0	0	6803	5230	106	0	0
BE	1002	0	28	165	14805	0	0	0	1	4722	0	0	0	3280	6052	1310	136	0	0
BG	868	0	2044	292	1678	0	2400	0	2	4082	0	1188	990	0	2599	1050	50	0	0
CH	0	0	12316	6048	0	0	1145	0	0	3692	0	0	0	0	295	1840	0	0	0
CY	11	0	0	0	1378	0	0	184	3	894	0	0	0	0	417	0	8	0	0
CZ	642	0	882	513	2901	435	6846	24	0	3089	0	2002	1095	0	838	1180	106	0	0
DE	6578	0	1628	5544	41436	0	0	674	6	86141	0	16112	7930	9369	77180	6810	756	0	0
DK	2601	0	0	10	3928	366	0	58	12	844	0	0	0	2787	4450	0	56	0	0
EE	366	0	0	20	910	0	0	0	8	0	0	468	0	132	1581	0	13	0	0
ES	2156	0	12628	4554	14782	0	0	782	201	43459	2200	97	0	153	46989	5150	370	0	0
FI	3130	0	1788	1960	4044	0	4952	49	5	25	0	327	0	388	2752	0	121	0	0
FR	3636	0	21900	4623	34612	448	32265	626	224	42950	4653	2890	0	3056	54513	7170	706	0	0
GR	260	0	3366	223	4900	0	0	153	20	8908	352	834	0	0	7884	700	71	0	0
HR	85	0	1256	1030	1000	0	0	16	10	2149	234	464	0	0	1340	282	26	0	0
HU	388	0	0	268	3460	0	3693	0	0	592	0	0	0	0	1616	0	62	0	0
IE	313	0	296	145	4632	0	0	0	6	19	0	0	0	375	5379	290	42	0	0
IT	6120	0	15450	4158	45090	0	0	128	14	53915	3000	1902	0	644	25314	7590	499	0	0
LT	166	0	0	286	496	0	1117	0	0	74	0	0	0	0	1144	900	16	0	0
LU	37	0	0	49	1244	0	0	0	0	160	0	0	0	0	485	1300	16	0	0
LV	134	0	0	1664	802	0	0	0	1	2	0	0	0	51	632	0	12	0	0
MT	0	0	0	0	1426	0	0	137	2	313	0	0	0	0	54	0	4	0	0
NL	2646	0	37	0	17802	0	0	0	2	5871	1200	3245	250	5000	7818	0	170	0	0
NO	0	0	47391	0	0	0	0	0	0	0	0	0	0	0	2495	1350	0	0	0
PL	3020	0	483	945	9232	0	8250	63	2	350	0	5032	4944	1887	16990	1790	282	0	0
PT	568	0	6946	3045	678	0	0	123	97	2916	336	0	0	27	7076	1420	64	0	0
RO	612	0	4917	1764	2511	976	2828	115	1	4143	0	0	885	0	7450	0	87	0	0
SE	3410	0	8195	9751	4761	0	9024	0	28	96	0	0	0	436	10784	100	216	0	0
SI	165	0	1248	217	820	0	1117	0	1	867	0	250	0	0	280	180	22	0	0
SK	462	0	1490	394	956	0	3021	0	0	1119	0	119	330	0	164	920	45	0	0
UK	18060	0	1694	121	45686	450	17295	339	2332	11255	0	0	448	16533	24935	2740	575	0	0

Table B2: Portfolio assumptions for High VRE scenario (MW)

	Biomass Waste (non-CCS)	Biomass Waste (CCS)	Hydro Lakes	Hydro ROR	Natural Gas (non-CCS)	Natural Gas (CCS)	Nuclear	Oil	Other RES	Solar	Solar CSP	Solids Fired (non-CCS)	Solids Fired (CCS)	Wind Offshore	Wind Onshore	Pumped Hydro Energy Storage	DAC	Power-to-gas	Demand Response
AT	2267	0	7385	4524	1390	0	0	177	0	4331	0	0	0	0	8792	5230	106	1295	879
BE	2685	0	24	140	7571	1604	0	90	3	17013	0	0	0	18026	12308	1310	136	4716	979
BG	1745	0	1735	248	727	0	792	90	9	1933	0	1073	894	0	2398	1050	50	428	492
CH	0	0	10458	5132	0	0	453	0	0	9744	0	0	0	0	4140	1840	0	0	0
CY	33	0	0	0	706	0	0	515	16	2695	0	0	0	0	2398	0	8	503	101
CZ	1936	0	749	435	2012	393	2711	361	0	4044	0	1807	989	0	2126	1180	106	609	751
DE	16092	0	1382	4704	23533	5663	0	1575	27	109039	0	16473	7162	73406	130355	6810	756	30897	4281
DK	6388	0	0	9	1702	331	0	665	56	5764	0	0	0	16955	11477	0	56	3376	439
EE	1104	0	0	17	479	0	0	181	39	773	0	423	0	652	2558	0	13	393	96
ES	5571	0	10714	3865	6466	3229	0	2118	921	59546	16900	88	0	7402	76071	5150	370	14121	2730
FI	7862	0	1518	1663	1753	0	1961	1173	21	4640	0	295	0	2172	11669	0	121	1824	854
FR	9135	0	18588	3924	19419	3236	12777	1481	1025	46400	35800	2609	0	43435	78405	7170	706	17725	5453
GR	784	0	2858	189	2124	0	0	271	94	13031	2700	753	0	6081	12308	700	71	3102	516
HR	935	0	1065	874	433	0	0	361	48	541	1800	419	0	0	3197	282	26	369	231
HU	1170	0	0	227	1499	0	1463	735	0	3093	0	0	0	0	3197	0	62	621	461
IE	944	0	251	123	2007	0	0	470	28	1547	0	0	0	4778	10390	290	42	1852	290
IT	15377	0	13111	3528	19543	4886	0	2086	64	45062	23400	3148	0	24838	28429	7590	499	9707	3805
LT	500	0	0	243	215	0	442	181	2	5400	0	0	0	869	1598	900	16	777	142
LU	112	0	0	42	539	0	0	181	0	201	0	0	0	0	400	1300	16	59	104
LV	404	0	0	1412	348	0	0	181	7	23	0	0	0	1086	1279	0	12	236	124
MT	0	0	0	0	618	0	0	247	7	994	0	0	0	0	0	0	4	98	41
NL	6499	0	31	0	10223	2813	0	181	7	35573	9100	2930	226	50891	11829	0	170	0	1193
NO	0	0	40200	0	0	0	0	0	0	0	0	0	0	869	16042	1350	0	9751	0
PL	7588	0	410	802	7805	2459	3267	722	11	32872	0	5880	5022	15202	52633	1790	282	9941	2097
PT	1712	0	5897	2584	294	0	0	554	444	13589	2600	0	0	5603	15985	1420	64	3473	475
RO	1845	0	4175	1497	1088	441	1120	208	5	4640	0	0	799	0	12788	0	87	1720	630
SE	8100	0	6960	8278	2124	0	3574	596	126	5183	0	0	0	2831	27842	100	216	3540	1672
SI	497	0	1059	184	355	0	442	90	3	756	0	226	0	0	400	180	22	114	162
SK	1393	0	1265	334	454	0	1196	90	0	1186	0	107	298	0	521	920	45	169	341
UK	42350	0	1438	109	19798	5688	6849	1219	10687	30160	0	4064	404	61528	31809	2740	575	13456	4190

Table B3: Portfolio assumptions for Negative Emissions scenario (MW)

	Biomass Waste	Biomass Waste (CCS)	Hydro Lakes	Hydro ROR	Natural Gas	Natural Gas (CCS)	Nuclear	Oil	Other RES	Solar	Solar CSP	Solids Fired	Solids Fired (CCS)	Wind Offshore	Wind Onshore	Pumped Hydro	DAC	Power-to-gas	Demand Response

	(non-CCS)				(non-CCS)							(non-CCS)				Energy Storage			
AT	2311	0	9893	6063	1849	0	0	0	0	5189	0	0	0	0	7760	5230	106	0	879
BE	2286	452	32	188	10990	0	0	0	5	5823	0	0	0	3018	10864	1310	136	0	979
BG	1697	335	2325	332	1056	0	3122	0	17	2306	0	0	0	0	2116	1050	50	0	492
CH	0	0	14015	6878	0	0	1787	0	0	6457	0	0	0	0	3654	1840	0	0	0
CY	39	0	0	0	1025	0	0	690	29	793	0	0	0	0	2116	0	8	0	101
CZ	1570	310	1003	584	1826	0	10686	0	0	4082	0	0	0	0	1877	1180	106	0	751
DE	15100	2984	1852	6307	33904	0	0	1631	50	76446	0	1839	0	19596	115061	6810	756	0	4281
DK	5652	1117	0	11	2472	0	0	140	104	3389	0	0	0	3795	10130	0	56	0	439
EE	1072	0	0	23	628	0	0	0	72	115	0	0	0	0	2257	0	13	0	96
ES	7530	1666	14371	5179	9333	0	0	1419	1717	46121	5200	0	0	0	67146	5150	370	0	2730
FI	8796	0	2034	2229	2545	0	7730	120	40	1384	0	0	0	914	10300	0	121	0	854
FR	8294	1639	24900	5257	26466	0	50362	1136	1913	36205	11000	0	0	9145	69206	7170	706	0	5453
GR	763	151	3827	254	3083	0	0	370	174	4612	832	0	0	390	10864	700	71	0	516
HR	909	180	1429	1172	629	0	0	484	89	231	552	0	0	0	2822	282	26	0	231
HU	949	187	0	305	2177	0	5765	0	0	2306	0	0	0	0	2822	0	62	0	461
IE	918	181	337	165	2915	0	0	0	53	577	0	0	0	914	9171	290	42	0	290
IT	14359	2837	17573	4730	28367	0	0	308	118	29045	7200	0	0	855	25093	7590	499	0	3805
LT	487	96	0	325	312	0	1744	0	4	92	0	0	0	0	1411	900	16	0	142
LU	130	0	0	56	783	0	0	0	0	231	0	0	0	0	353	1300	16	0	104
LV	393	78	0	1893	505	0	0	0	13	12	0	0	0	196	1129	0	12	0	124
MT	0	0	0	0	897	0	0	166	13	320	0	0	0	0	0	0	4	0	41
NL	7187	1420	42	0	15091	0	0	0	14	461	2800	0	0	15023	10441	0	170	0	1193
NO	0	0	53922	0	0	0	0	0	0	461	0	0	0	0	14160	1350	0	0	0
PL	8269	1634	549	1075	11279	0	12878	160	20	2802	0	1791	0	2939	46458	1790	282	0	2097
PT	2660	0	7897	3463	427	0	0	298	829	2094	800	0	0	78	14109	1420	64	0	475
RO	1795	355	5594	2006	1580	0	4414	278	9	2306	0	0	0	0	11287	0	87	0	630
SE	9075	0	9325	11088	3035	0	14086	0	235	2006	0	0	0	248	24576	100	216	0	1672
SI	484	96	1419	247	516	0	1744	0	6	369	0	0	0	0	353	180	22	0	162
SK	1355	268	1695	448	613	0	4716	0	0	826	0	0	0	0	460	920	45	0	341
UK	38263	7561	1927	146	28745	0	26995	820	19935	28703	0	0	0	28978	28077	2740	575	0	4190

Table B4: Transmission capacity for Reference scenario (MW)

Direction	Export Limit (MW)	Import Limit (MW)	Direction	Export Limit (MW)	Import Limit (MW)	Direction	Export Limit (MW)	Import Limit (MW)
AT-CZ	1000	-1200	DE-DK	4000	-4000	HU-HR	2000	-2000
AT-DE	7500	-7500	DE-FR	4800	-4800	HU-RO	1300	-1400
AT-HU	1200	-800	DE-LU	2300	-2300	HU-SI	1700	-1700

AT-IT	1655	-1385	DE-NL	5000	-5000	HU-SK	2000	-2000
AT-SI	1200	-1200	DE-PL	2000	-3000	IE-UK	1600	-1600
BE-DE	1000	-1000	DE-SE	1315	-1315	IT-SI	1380	-1530
BE-FR	2800	-4300	DK-NL	700	-700	LT-LV	2100	-1800
BE-LU	1080	-700	DK-NO	1640	-1640	LT-PL	1000	-1000
BE-NL	2400	-2400	DK-SE	2440	-1980	LT-SE	700	-700
BE-UK	1000	-1000	DK-UK	1400	-1400	NL-UK	1000	-1000
BG-GR	1728	-1032	EE-FI	1016	-1000	NO-DE	1400	-1400
BG-RO	1400	-1500	EE-LV	1600	-1600	NO-NL	700	-700
CH-AT	1700	-1700	ES-FR	8000	-8000	NO-SE	3695	-3995
CH-DE	4700	-3286	ES-PT	4200	-3500	NO-UK	1400	-1400
CH-FR	1300	-3700	FI-SE	2800	-3200	PL-SE	600	-600
CH-IT	6240	-3860	FR-IE	700	-700	PL-SK	990	-990
CY-GR	2000	-2000	FR-IT	4350	-2160	SI-HR	2000	-2000
CZ-DE	2600	-2000	FR-LU	380	0			
CZ-PL	500	-600	FR-UK	5400	-5400			
CZ-SK	2100	-1100	GR-IT	500	-500			

Table B5: Transmission capacity for High VRE scenario (MW)

Direction	Export Limit (MW)	Import Limit (MW)	Direction	Export Limit (MW)	Import Limit (MW)	Direction	Export Limit (MW)	Import Limit (MW)
AT-CZ	1000	-1200	DE-DK	8050	-8050	FR-UK	6750	-6750
AT-DE	7500	-7500	DE-FR	6600	-6600	GR-IT	500	-500
AT-HU	1200	-800	DE-LU	2300	-2300	HU-HR	2000	-2000
AT-IT	1655	-1385	DE-NL	7250	-7250	HU-RO	1300	-1400
AT-SI	1200	-1200	DE-PL	6500	-7500	HU-SI	1700	-1700
BE-DE	1000	-1000	DE-SE	1315	-1315	HU-SK	2000	-2000
BE-FR	3700	-5200	DE-UK	1800	-1800	IE-UK	2500	-2500
BE-LU	1080	-700	DK-NL	2500	-2500	IT-SI	1380	-1530

BE-NL	4200	-4200	DK-NO	1640	-1640	LT-LV	2100	-1800
BE-UK	1450	-1450	DK-PL	5400	-5400	LT-PL	1000	-1000
BG-GR	1728	-1032	DK-SE	5590	-5130	LT-SE	700	-700
BG-RO	1400	-1500	DK-UK	1400	-1400	NL-UK	1900	-1900
CH-AT	1700	-1700	EE-FI	1016	-1000	NO-BE	3600	-3600
CH-DE	4700	-3286	EE-LV	1600	-1600	NO-DE	5000	-5000
CH-FR	1300	-3700	ES-FR	8900	-8900	NO-NL	2500	-2500
CH-IT	6240	-3860	ES-PT	4200	-3500	NO-SE	3695	-3995
CY-GR	2000	-2000	FI-SE	2800	-3200	NO-UK	3200	-3200
CZ-DE	2600	-2000	FR-IE	700	-700	PL-SE	8700	-8700
CZ-PL	500	-600	FR-IT	4350	-2160	PL-SK	990	-990
CZ-SK	2100	-1100	FR-LU	380	0	SI-HR	2000	-2000

Table B6: Transmission capacity for Negative Emissions scenario (MW)

Direction	Export Limit (MW)	Import Limit (MW)	Direction	Export Limit (MW)	Import Limit (MW)	Direction	Export Limit (MW)	Import Limit (MW)
AT-CZ	1000	-1200	DE-DK	4000	-4000	HU-HR	2000	-2000
AT-DE	7500	-7500	DE-FR	4800	-4800	HU-RO	1300	-1400
AT-HU	1200	-800	DE-LU	2300	-2300	HU-SI	1700	-1700
AT-IT	1655	-1385	DE-NL	5000	-5000	HU-SK	2000	-2000
AT-SI	1200	-1200	DE-PL	2000	-3000	IE-UK	1600	-1600
BE-DE	1000	-1000	DE-SE	1315	-1315	IT-SI	1380	-1530
BE-FR	2800	-4300	DK-NL	700	-700	LT-LV	2100	-1800
BE-LU	1080	-700	DK-NO	1640	-1640	LT-PL	1000	-1000
BE-NL	2400	-2400	DK-SE	2440	-1980	LT-SE	700	-700
BE-UK	1000	-1000	DK-UK	1400	-1400	NL-UK	1000	-1000
BG-GR	1728	-1032	EE-FI	1016	-1000	NO-DE	1400	-1400
BG-RO	1400	-1500	EE-LV	1600	-1600	NO-NL	700	-700
CH-AT	1700	-1700	ES-FR	8000	-8000	NO-SE	3695	-3995

CH-DE	4700	-3286	ES-PT	4200	-3500	NO-UK	1400	-1400
CH-FR	1300	-3700	FI-SE	2800	-3200	PL-SE	600	-600
CH-IT	6240	-3860	FR-IE	700	-700	PL-SK	990	-990
CY-GR	2000	-2000	FR-IT	4350	-2160	SI-HR	2000	-2000
CZ-DE	2600	-2000	FR-LU	380	0			
CZ-PL	500	-600	FR-UK	5400	-5400			
CZ-SK	2100	-1100	GR-IT	500	-500			

H-VRE-BECCS Scenario

This sensitivity replaced 16 GW of Coal-CCS with 16 GW of BECCS in the High VRE scenario. Table 7 outlines the main results of the sensitivity analysis compared to the counterfactual, with and without DAC.

Table B7: Overview of gross CO_2 production and CO_2 capture in several scenarios.

	High VRE	High VRE w. DAC	High VRE w. BECCS	High VRE w. BECCS_DAC
CO_2 Gross Production ($MtCO_2$) - Natural Gas	117.6	125.8	99.5	107.4
CO_2 Gross Production ($MtCO_2$) - Oil	0.2	0.2	0.1	0.1
CO_2 Gross Production ($MtCO_2$) - Coal	53.5	53.7	1.3	1.6
Negative CO_2 Emissions - BECCS ($MtCO_2$)	0	0	-52.7	-52.8
Abated CO_2 from Coal & Natural Gas Capacity ($MtCO_2$)	-79.6	-80.0	-30.6	-31.0
Negative CO_2 Emissions - DAC ($MtCO_2$)	0	-111.0	0	-111.0
Total CO_2 Emissions Released ($MtCO_2$)	91.7	-11.2	17.6	-85.6
Carbon Intensity (kg MWh^{-1})	21.5	23.2	4.1	5.9
Carbon Intensity (kg MWh^{-1}) w. DAC	21.5	-2.6	4.1	-19.8

Breakdown of Total System Costs

Table B8: Breakdown of total system costs per scenario (€billion).

Scenarios		Disaggregated Costs			
Pathway	Variant	CAPEX	OPEX	Total System Cost	Carbon-related Costs
Reference	REF	€ 70	€ 105	€ 175	€ 40
	REF - DAC	€ 73	€ 122	€ 195	€ 35
	REF - No CCS	€ 70	€ 103	€ 173	€ 47
High VRE	H-VRE	€ 164	€ 53	€ 218	€ 24
	H-VRE - DAC	€ 168	€ 71	€ 239	€ 6
	H-VRE - No CCS	€ 163	€ 52	€ 216	€ 33
	H-VRE - BECCS	€ 158	€ 51	€ 210	€ 5
	H-VRE - BECCS_DAC	€ 162	€ 69	€ 231	-€ 14
	H-VRE - No PtG	€ 143	€ 53	€ 196	€ 30
Negative Emissions	NE	€ 122	€ 53	€ 174	-€ 8
	NE - DAC	€ 125	€ 71	€ 196	-€ 26
	NE - No CCS	€ 122	€ 53	€ 175	€ 40

Appendix C: Supplementary Material – Chapter 6

To promote transparency in the energy modelling community, our complete model is freely available within the Supplementary Material (also see https://energyexemplar.com/datasets/ for the PLEXOS® model).

The necessary data to replicate Jacobson, et al.'s (Jacobson et al., 2018) WWS cases for the European region is acquired from Delucchi et al. (2016) and the Supporting Information (Jacobson et al., 2018). Other data was requested, and granted, directly from the authors via email correspondences.

Generation

Generation capacities are categorised by class, e.g. hydro, solar PV, onshore wind, geothermal electric, dispatchable, et cetera. Portfolios are disaggregated into individual power plant types by technology class and assigned standard technical characteristics as shown 0in Table C1, an approach previously used by Ref. (Gaffney et al., 2018; Gaffney et al., 2019a). All new dispatchable generation capacity efficiency is assumed to be high efficiency (60%) combined cycle gas turbine technology capacity.

Normalised hourly generation profiles for wind power (onshore and offshore)(Staffell and Pfenninger, 2016), and solar (photovoltaic(Pfenninger and Staffell, 2016a) and concentrated solar power)(Pfenninger and Staffell, 2016a) from 1985 to 2016 were obtained for each country from the Renewable.ninja (Pfenninger and Staffell, 2016b). Thermal energy storage associated with concentrated solar power is modelled using an approach outlined by Denholm and Hummon (2012); (Denholm and Mehos, 2014; Denholm et al., 2013). Storage capacity assumptions align with source material (Jacobson et al., 2018), in that we assume the storage is sized at 14 hours of charging rate which is 1.61 times larger than discharge rate, thereby making storage 22.5 hours. This means the solar field is 2.61 times larger than the discharge capacity. We assume the overall CSP round-trip efficiency is 40% based on observations from Spanish CSP operations. Solar thermal generation profiles are based on solar PV profiles scaled to capacity factors outlined in source material. Generation profiles and installed capacity distribution among European countries for both tidal and wave technologies were carried out in alignment with Jacobson et al. (2018), i.e. the former applies a flat profile and the latter uses offshore wind profiles from the specific country scaled to specific capacity factors as identified in the source material. Individual hydro profiles were decomposed from monthly generation constraints from ENTSO-E (ENTSO-E, 2012) to weekly and hourly profiles in the optimisation algorithm function within PLEXOS® which, on an annual basis, align with capacity factors assumed by Jacobson et al. (2018). Pumped hydro energy storage assumptions align with Ref. (Jacobson et al., 2018), e.g. 80% efficiency.

Table C1: The standardised generation characteristics applied for all 40 countries. Dispatchable power uses the efficiency characteristics of a nuclear power station(International Energy Agency, 2017b).

Fuel Type	Capacity (MW)	Min Stable Factor (%)	Ramp Rate (MW/Min)	Efficiency (%)
Dispatchable	500	30	5	60%
Geothermal Electric	70	40	5	-
Hydro	150	5	10	-
Pumped Hydro	200	10	30	80% (Jacobson et al., 2018)
Solar (CSP)	100	40	30	40% (Jacobson et al., 2018)

Table C2: Installed generation capacity for the European region in original scenarios (GW)

Technology	Case A	Case B	Case C
Geothermal Elec	3.1	3.0	3.1
Geothermal Heat	22.3	22.3	22.3
Hydro	160.2	640.9	160.2
Tidal	15.0	15.0	15.0
Wave	37.7	37.7	37.7
Solar (PV)	3060.3	4248.9	2578.2
Solar (CSP)	63.3	202.8	63.3
Solar (Thermal)	153.4	0.0	0.0
Wind Onshore	2601.9	1735.1	1518.0
Wind Offshore	665.3	628.4	443.5

Table C3: Installed generation capacity for the European region in “Include VRE” scenarios (GW)

Technology	Case A	Case B	Case C
Geothermal Elec	3.1	3.0	3.1
Geothermal Heat	22.3	22.3	22.3
Hydro	160.2	640.9	160.2
Tidal	15.0	15.0	15.0
Wave	37.7	37.7	37.7
Solar (PV)	4388.3	4394.8	2578.2
Solar (CSP)	63.3	202.8	63.3
Solar (Thermal)	153.4	0.0	0.0

Wind Onshore	2601.9	2688.5	3306.0
Wind Offshore	2727.9	2073.3	764.8

Table C4: Installed generation capacity for the European region in "Include Dispatchable power" scenarios (GW)

Technology	Case A	Case B	Case C
Geothermal Elec	3.1	3.0	3.1
Geothermal Heat	22.3	22.3	22.3
Hydro	160.2	640.9	160.2
Tidal	15.0	15.0	15.0
Wave	37.7	37.7	37.7
Solar (PV)	3060.3	4248.9	2578.2
Solar (CSP)	63.3	202.8	63.3
Solar (Thermal)	153.4	0.0	0.0
Wind Onshore	2601.9	1735.1	1518.0
Wind Offshore	665.3	628.4	443.5

Reserve Requirements

Once a power imbalance occurs reserves are activated to contain and then restore frequency. In chapter6 these are referred to as containment and restorative reserves respectively. Literature suggests that reserve requirements may increase in accordance with the level of VRE installed in a system (Brouwer et al., 2014; Holttinen et al., 2008; Papavasiliou et al., 2011). Brouwer et al. (2014) for example, estimates that secondary, tertiary and replacement reserves may increase by 7% of installed wind capacity. Here, we apply a published methodological approach by Holttinen et al. (2008) to estimate the increased operational reserve requirements for the restorative reserve using 3.5 standard deviations (99.9 percentile) (Dvorkin et al., 2015) which results in a dynamic reserve equal to 6.8% of generating VRE. When modelled, this dynamic reserve is held in parallel with the containment reserve requirements in continental Europe, i.e. 3 GW.

Demand

Table C5: Annual average all-sector inflexible and flexible loads (GW) for 2050 for European region used in this study for Cases A, B and C

Scenario	Total Load (GW)	Inflexible Load (GW)	Flexible Load (GW)	Cold load subject to	Low-temperature heat load subject to	Load subject to DR (GW)	Load for H2 (GW)

				storage (GW)	storage (GW)		
Case A	1420	355.2	1065	79.2	566.2	317.2	101.9
Case B	1420	355.2	1065	79.2	566.2	317.2	101.9
Case C	910.1	491.1	419	0	0	317.2	101.9

Inflexible load for all cases uses profiles attained from ENTSO-E's TYNDP 2018 (ENTSO-E, 2018b). The load series applied is the forecasted load profiles for a "Distributed Generation" scenario in 2040. This scenario was chosen as it is most similar to the WWS proposal in terms of non-centralised power generation. ENTSO-E (2018b) provide hourly resolution demand curves for 35 of the 40 countries for different climatic conditions, i.e. normal (1984), wet (1982) and dry (2007). We applied the normal climatic conditions. The remaining 5 countries used demand profiles from neighbouring countries: Belarus (Lithuania), Gibraltar (Spain), Moldova (Romania), Ukraine (Poland) and Kosovo (Serbia). These demand profiles were linearly scaled to the overall demand estimates used for each case.

The inflexible base load, that is common across all three cases (355.2 GW), is distributed across the 40 countries as outlined by Jacobson et al. (2018) and applies the aforementioned profiles. The additional inflexible demand in Case C, 135.9 GW, derive from thermal loads and as such, have profiles more aligned with the nature of their individual loads, as discussed next.

Thermal loads, cold and low-temperature loads, are distributed based on Cooling Degree Days (CDD) and Heating Degree Days (HDD) as demonstrated in the Supporting Information by Jacobson et al. (2018). In aligning with the source material, we also apply the minimum CDD and HDD of 0.01-degree day per day to represent energy expended for refrigeration and water heating needs, respectively. The CDD and HDD data for 2013-2014 was acquired from authors following a request. Short term energy storage (STES) is assumed to have 6 hours storage. Underground thermal energy storage (UTES) is assumed to have 4 days and 11 days' worth of storage for Case A and B respectively.

While these thermal loads are considered flexible in Case A and B, Case C does not. Therefore, the previously mentioned 135.9 GW delta in inflexible load is distributed between the thermal loads proportionally and assumes the same load profile yet is considered inflexible.

Power-to-gas (PtG) load (hydrogen used in transport sector) is considered constant across the year. There is 2 days' worth of hydrogen storage assumed for the European region in all three cases. We assumed that storage can fully charge in 6 hours and that the entire process is 68%

efficient. The latter comes from assumptions on page 7 of Supporting Information regarding energy used for conversion.

Demand response load is considered constant across the year in terms of daily load. This load can be 'shifted' by up to 8 hours within day, at which point it become inflexible and must be fulfilled. We assume this process is 100% efficient. Demand response can charge and discharge storage capacity in 2 hours.

Types of flexible load

There are different types of flexible loads incorporated into this analysis. The first is load shifting, i.e. demand response. This can move a load up to 8 hours within day. The second are loads which can be stored days in advance of when it may be needed. Hydrogen and UTES are prime examples. Respectively, these loads must be met using energy generated at the time of the demand or come from storage. If we consider the start position of stored energy in each type at the beginning of the simulation horizon, the first can buy or sell power from the beginning of the day whereas the second must buy energy and store energy before being able to provide the benefits of being a flexible load.

Storage

Demand response storage is sized to allow the average hourly load to shift by up to 8 hours within day. We assume this process is 100% efficient. The storage capacity can charge and discharge in 2 hours.

Hydrogen storage capacity is sized to hold 2 days' worth of hydrogen demand for the European region in all three cases. We assume storage can fully charge in 6 hours and that the entire process is 68% efficient. The latter comes from energy conversion assumptions on page 7 of Supporting Information. Hydrogen is not subject to demand response therefore the energy released from storage is only used for the hydrogen load which is constant around the entire period being simulated.

Pumped hydro energy storage (PHES) has its energy and capacity aligned with the supplementary information paper. The efficiency of PHES is assumed 80%.

Stationary battery capacity is sized in accordance with Jacobson's approach, i.e. 1000 GW and 100 GW in Case A and C respectively, with 1.94 hrs capacity. We assume stationary battery storage is 90% efficient.

Short term energy storage (STES), i.e. CW-STES, HW-STES and ICE, energy and capacity assumptions are in alignment with the source material. We combine the STES capacities for simulation purposes. This results in an efficiency of 83.4%; weighted average of the charging rates of the three contributors, see Table S3 in Supporting Information of Ref.(Jacobson et al., 2018). The charge/discharge and storage capacity of STES aligns with Table S4 of Supporting Information.

Underground thermal energy storage (UTES) is charged by a combination of thermal and electrical means. This storage capacity aligns with the source material. The round-trip efficiency is assumed 56%, see Table S3 in Supporting Information. The charge/discharge and storage capacity of STES aligns with Table S4 of Supporting Information.

Table E6: Summary of storage capacities

Technology	Capacity (GWh)	Charge/Discharge Rate (GW)	Efficiency (%)
Stationary Battery	1940 (Case A) 194 (Case C)	1000 (Case A) 100 (Case C)	90 90
Hydro	634.2	160.2 (Case A & C) 640 (Case B)	45.2 (Annual Capacity Factor)
Pumped Hydro	2780	198	80
Demand Response	2537	1268	100
Power-to-Gas	4890	815	40.8
Solar CSP	1431 (Case A & C) 4582 (Case B)	63.4 (Case A & C) 202.8 (Case B)	40
STES	10620	1665.2	83.4
UTES	152300 (Case A) 418800 (Case B)	2533.4 (Charge – Case A) 2380 (Charge – Case B) 1586 (Discharge)	56

Cross Border Transmission

Cross-border transmission capacity assumptions are not specified in the source material (Jacobson et al., 2018). Instead it is assumed that if congestion is an issue, increasing transmission capacity would only result in a modest increase in cost. The long-term planning algorithm in PLEXOS® is used to calculate the cost-optimal transmission capacity requirements between countries to avoid unserved energy where possible. Energy flow across transmission capacities is modelled as simple active power transport rather than optimised power flow which would include active and reactive power balance constraints. Wheeling charges of €3/MWh are included on each interconnector to account for losses. There is no transmission capacity between World Regions, i.e. the European region is energy isolated.

Fuel

The fuel price assumed for dispatchable power remains consistent across all cases at \$27 GJ^{-1} ($\$_{2013}$) whether consuming natural gas or a synthetic alternative. E-gas is created using otherwise curtailed electricity which excess after all energy and ancillary service requirements are met. We assume the conversion to gas is 68% efficient. When coupled with the efficiency of the combined cycle gas turbine, the full roundtrip efficiency of power-to-gas and back to power is 40.8%.

Operational Assumptions

System Adequacy

This paper uses the same approach to system adequacy as the ENTSO-E's Mid-term Adequacy Forecast 2017 (ENTSO-E, 2017a), in that we consider the maximum acceptance level of power shortages for the entire European region to be 0.004% of total annual electricity demand. This limit is based on 36 European countries in 2025, the furthest year analysed, which are in the WWS roadmaps, i.e. Unserved Energy 139.9 GWh, Demand 3390.7 TWh.

Total Power System Cost Assumptions

Total power system costs are calculated using data from multiple sources (Carlsson, 2014; International Energy Agency, 2017b; Jacobson et al., 2018; Tsiropoulos et al., 2017). Lifetime, capital expenditures, operation and maintenance costs, decommissioning cost and cost of storage are visible from Table C8. In this analysis we employ the European Commission's definition of 'total system costs' (European Commission, 2014b). Total system costs are annualised, undiscounted costs where the CAPEX is spread over the technical lifetime of the technology with variable costs also included.

Demand-side costs are excluded; therefore, the total power system costs are akin to a supply side cost. Supply side energy system costs include capital costs for energy installations (e.g. power plants) and energy infrastructures such as interconnection capacity and energy purchase costs. These costs do not reflect whole system costs which typically include costs associated with all energy-using equipment, appliances, vehicles and efficiency investment costs. For instance, costs associated with converting electrical energy into thermal energy are not accounted for as is the case with the source material (Jacobson et al., 2018).

Costs associated with creating e-gas are assumed to be covered with a fuel price of \$27 GJ^{-1}.

Table C8: Cost assessment assumptions for the various aspects to be considered ($$_{2013}$). *Dispatchable generation characteristics assume that of nuclear power (International Energy Agency, 2017b). **Lifetime of storage element to Solar CSP technology.

Type	Lifetime (Year)	CAPEX ($ kW^{-1})	O&M ($ kW/yr^{-1})	Decommissioning Cost (% of CAPEX)	Cost of Storage ($ kWh^{-1})
Dispatchable*	35	$1,140	$4.56	2.50%	-
Geothermal Electric	45	$4,370	$45.00	2.50%	-
Geothermal Heat	45	$4,370	$45.00	2.00%	-
Hydro	85	$2,920	$15.50	2.50%	-
Hydro – Power Capacity Expansion	85	$385	$15.50	2.50%	-
Tidal	45	$3,850	$125.00	2.50%	-
Wave	45	$4,330	$175.00	2.00%	-
Solar PV	48	$1,830	$20.31	0.75%	-
Solar CSP	45 (32.5**)	$6,240	$50.00	1.25%	$20.00
Solar Thermal	35	$1,350	$50.00	1.25%	-
Wind Onshore	30	$1,510	$37.00	1.25%	-
Wind Offshore	30	$3,920	$80.00	2.00%	-
Interconnection	60	$522/km(Carlsson, 2014)	$18.27	-	-
Battery	32.5	-	-	-	$160.00
Pumped Hydro	32.5	-	-	-	$14.00
STES	32.5	-	-	-	$8.38
UTES	32.5	-	-	-	$0.90
Power-to-gas	32.5	-	-	-	Case A & B: $0.00135 Case C: $0.00211

Generation Capacity Factor Comparison

Capacity factor comparison by technology

Table C9: Comparing assumed, actual and potential capacity factors. For the actual capacity factors, we use the mean of the 30 samples utilised for wind and solar PV generation. Potential represents the capacity factor when no energy curtailment or reserve provision takes place.

Technology	WWS Assumptions	Our Assumptions	Resulting
Geothermal Elec	81.6%	81.6%	81.1%
Geothermal Heat	97.3%	97.3%	91.0%
Hydro	45.2%	45.2%	45.2%
Tidal	22.4%	22.4%	21.4%
Wave	19.5%	23.9%	23.1%
Solar PV	18.9%	12.9%	12.1%
Solar CSP	49.5%	49.5%	37.3%

Solar Thermal	7.2%	7.3%	6.9%
Wind Onshore	35.0%	23.2%	22.4%
Wind Offshore	36.3%	32.3%	31.1%

Hydro capacity factor assumptions

Figure C1 demonstrates the difference when we introduce historic monthly capacity factor constraint which reflects the actual generation from hydro versus using an annual capacity factor. While both equal the same capacity factor on an annual basis, i.e. 45.2%, the two approaches are very different in terms of generation profile per month.

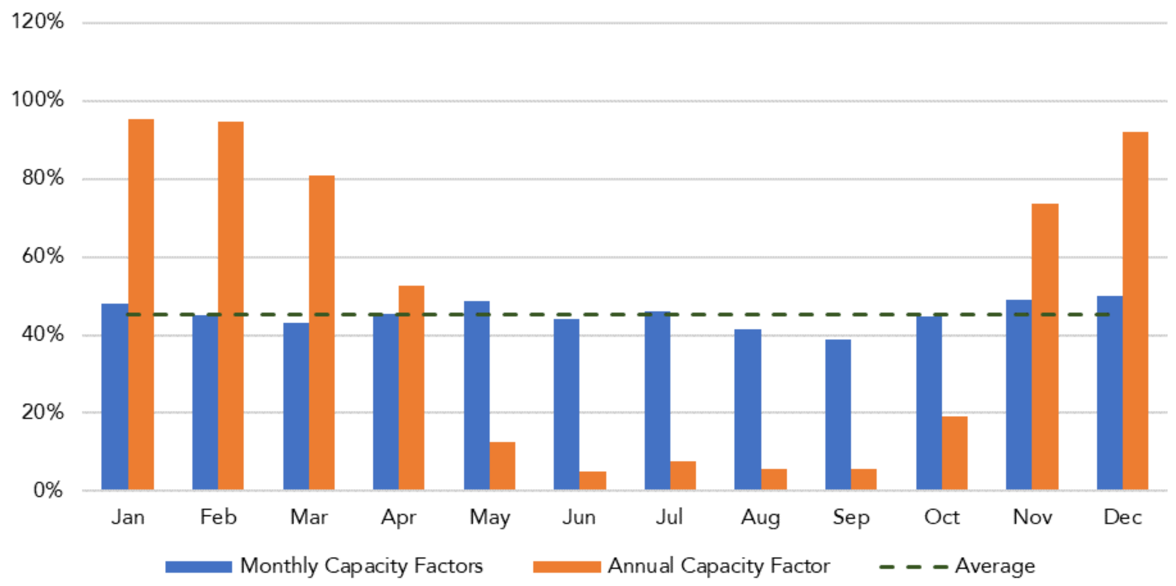


Figure C1: Comparing hydro capacity factors when constrained by monthly profiles or using an annual average.

Long Term Capacity Expansion

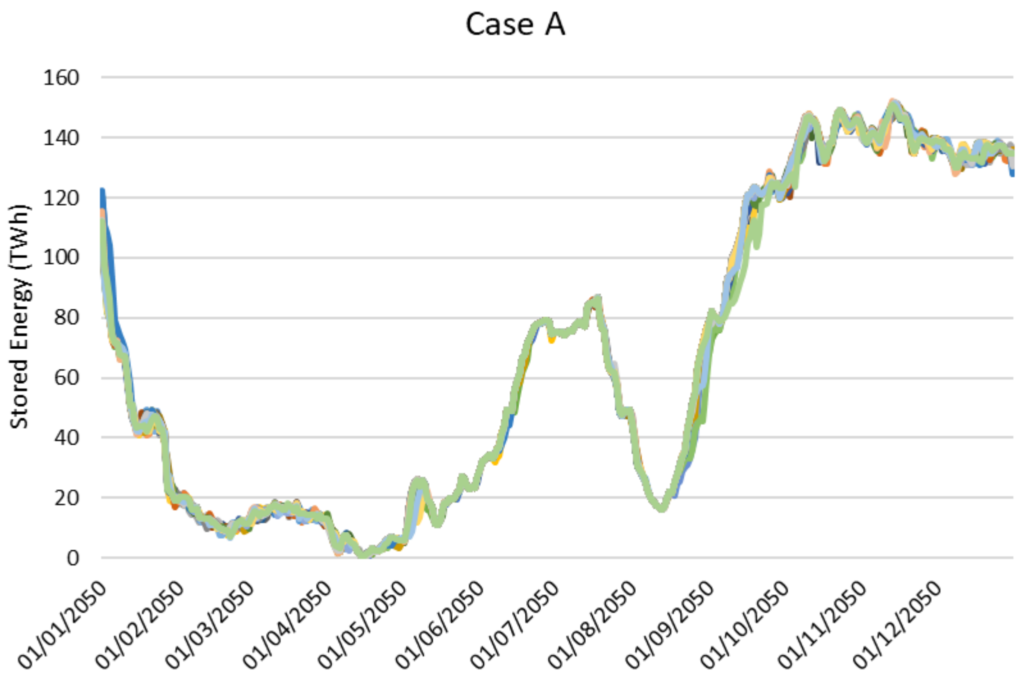
The transmission network was expanded using the long term (LT) planner in PLEXOS®. Assuming build costs and technical lifetimes demonstrated in Table C8, the software built the required capacity to avoid unserved energy, where possible. We did not limit the size of expansion between countries.

The dispatchable capacity was expanded using the long-term planner in PLEXOS®. Assuming CAPEX and technical lifetime assumptions demonstrated in Table C8, the software built the required capacity to avoid unserved energy. We did not limit the commissioned capacity per country.

VRE capacity was expanded using the long-term planner in PLEXOS®. Assuming CAPEX and technical lifetime assumptions demonstrated in Table C8, the software built the required capacity to avoid unserved energy. We did limit the commissioned capacity per country at estimated potentials listed in the Supplementary Material from Jacobson et al. (2018), i.e. onshore wind: 2152 GW, offshore wind: 2331 GW and Solar PV: 96000 GW. The only exception was the assumption around onshore wind. The estimated potential for onshore wind appears larger in the WWS Case A scenario than suggested in the Supplementary Material, therefore we assume that onshore wind energy cannot expand beyond 2602 GW in any scenario with capacity expansion as an option.

Seasonal patterns of large thermal storage capacity

Figure C2 illustrates the seasonal storage volumes across 12 months for both Case A & B. The maximum storage volumes were 152.3 TWh and 418.8 TWh for Case A & B respectively.



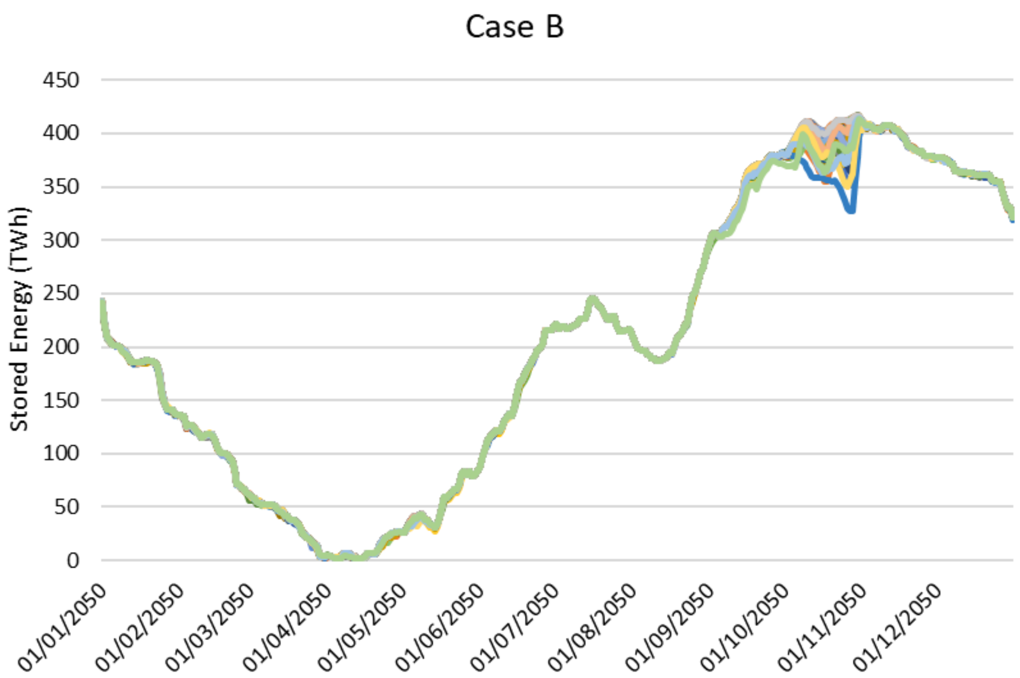


Figure C2: The seasonal underground thermal energy storage (UTES) volumes for Case A & Case B in all 30 individual samples. Case C does not include any UTES.