The Impact of Low Carbon Technologies on the British Wholesale Electricity Market

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Lay Summary

The addition of novel low-carbon technologies, such as energy storage, customer driven platforms like demand side management, and renewable energy generation ranging from wind to solar to marine power is already reshaping the British power system and will have a major impact on its future. In Great Britain, the support for this addition comes from the desire to decrease the greenhouse gas emissions and diversify the energy system, allowing for an increased electricity supply, in addition to more flexible operation and lower marginal costs.

Technological advancements such as energy storage and demand side management help with the intermittent nature of renewable resources by providing stability and predictability that is not commonly associated with renewable generation. Further, new power plants such as modern combined cycle gas turbines, pollute much less than their predecessors and have impressive efficiency rates. Fossil fuel-fired power plants can also be equipped with carbon capture and storage technologies.

In this work, a cost-minimisation model is developed to evaluate how the British wholesale electricity market will react to the increasing renewable generation capacity in the energy system and what will be the impact on the electricity prices and policy making. Upon obtaining simulated wholesale electricity prices resulting from different case study scenarios, the interactions between different generating profiles are analysed. A sensitivity analysis investigates the impact of different capacities of energy storage and demand side management in the system.

This interdisciplinary research presents a detailed assessment of the long-term effect modern generating technologies will have on the prices of the British wholesale electricity market. It includes low-carbon generation and smart technologies discussed in present times and breaks down past and present policy decisions to determine how future targets would have to be developed and implemented for the British transition into a green economy to be a policy and financial success for all market actors.

Abstract

Since the late 1980s, the energy sector in Great Britain has undergone some core changes in its functionality; beginning with the early 1990s privatisation, followed by an increased green ambition, and commencing a transition towards a low-carbon economy. As the British energy sector prepares itself for another major overhaul, it also puts itself at risk for not being sufficiently prepared for the consequences this transition will have on the existing generating capacity, security of supply, and the national electricity market.

Upon meeting existing targets, the government of the United Kingdom risks becoming complacent, putting energy regulation to the backseat and focusing on other regulatory tasks, while introducing cuts for thriving renewable and other low-carbon energy generating technologies. The government has implemented a variety of directives, initiatives, and policies that have sometimes been criticised due to their lack of clarity and potential overlap between energy and climate change directives. The government has introduced policies that aim to provide stable short-term solutions. However, a concrete way of resolving the energy trilemma and some of the long-term objectives and more importantly ways of achieving them are yet to be developed.

This work builds on analysing each low-carbon technology individually by assessing its past and current state in the British energy mix. By accounting for the changes and progress the technology underwent in its journey towards becoming a part of the energy capacity in Great Britain, its impact on the future wholesale electricity prices is studied.

Research covered in this thesis presents an assessment of the existing and incoming low-carbon technologies in Great Britain and their individual and combined impact on the future of British energy economics by studying their implications for the electricity market. The methodological framework presented here uses a cost-minimisation merit order model to provide useful insights for novel methods of electricity production and conventional thermal energy generation to aid with the aftermath of potential inadequate operational and fiscal flexibility.

The thesis covers a variety of scenarios differing in renewable and thermal penetration and examines the impact of interconnection, energy storage, and demand side management on the British wholesale electricity prices. The implications of increasing low-carbon capacity in the British energy mix are examined and compared to similar developments across Europe.

The analysis highlights that if the optimistic scenarios in terms of green energy installation are followed, there is sufficient energy supply, which results in renewable resources helping to keep the wholesale price of electricity down. However, if the desired capacity targets are not met, the lack of available supply could result in wholesale prices going up, especially in the case of a natural gas price increase. Although initially costly, the modernisation of the British

grid leads to a long-term decrease in wholesale electricity prices and provides a greater degree of security of supply and flexibility for all market participants.

Acknowledgements

I would like to thank my parents, my brother, my (official & unofficial) supervisors that succoured me, and everyone that I met during my time in Cambridge, Edinburgh, Karlsruhe, and London that helped make this thesis happen, especially Manuel without whom this would not have been possible.

Declaration

I declare that this thesis was composed by myself, that the work contained herein is my own except where explicitly stated otherwise in the text, and that this work has not been submitted for any other degree or professional qualification except as specified.

Sara Lupo

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Figures and Tables

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Nomenclature

ACEEE	American Council for an Energy Efficient Economy
ACS	Average cold spell
AD	Anaerobic digestion
AMAPE	Average mean absolute percentage error
ARMAX	Autoregressive moving average with exogenous variables
AWNN	Adaptive wavelet neural network
BAT	Best Available Techniques
BEIS	Department for Business, Energy and Industrial Strategy
BETTA	British Electricity Trading and Transmission Arrangements
BEV	Battery electric vehicle
BM	Balancing mechanism
BSCCo	Balancing and Settlement Code Company
CAES	Compressed air energy storage
CCA	Climate Change Act
CCC	Committee for Climate Change
CCGT	Combined cycle gas turbine
CCL	Climate Change Levy
CCR	Carbon capture ready
CCS	Carbon capture and storage
CEGB	Central Electricity Generating Board
CERO	Carbon Emissions Reduction Obligation
CERT	Carbon Emissions Reduction Target
CESP	Community Energy Saving Programme
CfD	Contracts for Difference
CHP	Combined heat and power
CM	Capacity market
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
CP	Consumer Power
CPF	Carbon price floor
CPP	Critical Peak Pricing
CPS	Carbon price support
CRC	Carbon Reduction Commitment
CSCO	Carbon Saving Community Obligation
DA	Devolved administration

DECC	Department of Energy and Climate Change
DEFRA	Department for Environment and Rural Affairs
DG ENER	Directorate-General for Energy
DNO	Distribution network operator
DR	Demand response
DSM	Demand side management
DSR	Demand side response
DTI	Department of Trade and Industry
EC	European Commission
ECA	Enhanced Capital Allowances
ECCC	Energy and Climate Change Committee
ECO	Energy Company Obligation
ED-CPP	Extreme Day Critical Peak Pricing
EDP	Extreme Day Pricing
EDR	Electricity Demand Reduction
EEC	Energy Efficiency Commitment
EED	Energy Efficiency Directive
EEDO	Energy Efficiency Deployment Office
EES	Electrical energy storage
EES	Energy Efficiency Strategy
EESoP	Energy Efficiency Standards of Performance
EIA	Energy Information Administration
ELF	Energy Labelling Framework
EMHIRES	European Meteorological derived high resolution renewable energy source generation time series
EMR	Electricity Market Reform
ENTSO-E	European Network of Transmission System Operators
EOR	Enhanced oil recovery
EPS	Emission performance standard
ES	Energy storage
ESME	Energy System Modelling Environment
EST	Energy Savings Trust
ETI	Energy Technologies Institute
ETL	Energy Technology List
ETS	Emissions Trading Scheme
EU	European Union
EV	Electric vehicle
FCS	Forestry Commission Scotland
FES	Future Energy Scenario

FiT	Feed-in tariff
GB	Great Britain
GEMA	Gas and electricity market authority
GG	Gone Green
GHG	Greenhouse gas
GW	Gigawatt
HHCRO	Home Heating Cost Reduction Obligation
Hz	Hertz
IBP	Incentive-Based Programmes
IC	Interconnection
ICB	Iron-chromium battery
IEA	International Energy Agency
IED	Industrial Emissions Directive
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
ISO	Independent system operator
kW	Kilowatt
kWh	Kilowatt hour
LAES	Liquid air energy storage
LCF	Levy Control Framework
LCPD	Large Combustion Plant Directive
LED	Light-emitting diode
LHTES	Latent heat thermal energy storage
Li	Lithium
LPG	Liquefied petroleum gas
MAPE	Mean Absolute Percentage Error
MARKAL	Market allocation
METIS	Modelling the European Energy System
MILP	Mixed-integer linear programming
MPEC	Mathematical programming with equilibrium constraints
MtCO_2	Mega-tonnes of carbon dioxide
MW	Megawatt
MWh	Megawatt hours
Mtpa	Metric tonnes per annum
NAP	National Adaptation Plan
NER 300	New Entrants Reserve 300
NETA	New Electricity Trading Arrangements
NG	National Grid
NGC	National Grid Company

NGET	National Grid Electricity Transmission
NI	Northern Ireland
NP	No Progression
NPV	Net Present Value
NTC	Net Transfer Capacity
O&M	Operations and management
OBR	Office for Budget Responsibility
OCGT	Open cycle gas turbine
OFFER	Office of Electricity Regulation
OFTO	Offshore Transmission Owners
OPEC	Organization of the Petroleum Exporting Countries
Pb	Lead
PBP	Price-Based Programmes
PCAST	President's Council of Advisors on Science and Technology
PCC	Post combustion capture
PHES	Pumped hydropower energy storage
PHEV	Plug-in hybrid electric vehicle
PJM	Pennsylvania-New Jersey-Maryland
PV	Photovoltaic
REC	Regional electric companies
RED	Renewable energy directive
RHI	Renewable heat incentive
RO	Renewable obligation
ROA	Real option analysis
RTP	Real Time Pricing
SHETL	Scottish Hydro-Electric Transmission Limited
SMV	Support Machine Vector
SO	Supplier obligation
SP	Slow Progression
SPTL	Scottish Power Transmission Limited
SRMC	Short-run marginal cost
SSE	Scottish and Southern Energy
SSEB	South of Scotland Electricity Board
STA	Solar Trade Association
STOR	Short Term Operating Reserve
TOU	Time of Use
TSO	Transmission system operator
TWh	Terawatt hour
UK	United Kingdom

UKERC	United Kingdom Energy Research Centre
UN	United Nations
US	United States
USA	United States of America
US DOE	United States Department of Energy
VEC	Vector error correction
VRB	Vanadium redox battery
ZNBR	Zinc-Bromine battery

Symbols

$\forall$	For all
α	Empirically determined uplift coefficient
β	Empirically determined uplift coefficient
$c_{emission}$	Cost of CO_2/emission
c_{fuel}	Fuel cost
$C_{ic,i}$	Capacity of interconnector i
$C_{ic,x}$	Aggregated capacity of interconnectors already included in the merit order
$c_{O\&M}$	Operations and maintenance cost
C_{tech}	Marginal cost of the current technology in the merit order
C_{tech+1}	Marginal cost of the next technology in the merit order
D	Demand
$D_{avg,base}$	Average values of the base time series
$D_{avg,goal}$	Average values of the the future time series
$D_{max,base}$	Peak values of the base time series
$D_{max,goal}$	Peak values of the future time series
D_t	Net demand of time step t
d_t	Scenario time series
$d_{t,base}$	Base time series
η	Efficiency of the power plant
η_{RT}	Roundtrip efficiency
$f_{emission}$	Emission factor of the used fuel
G_t	Storage change due to the chosen operation in time step t
n_{ic}	Number of interconnectors
p	Price
p_{IC}	Market price of the interconnector
$P_{i,new}$	Adjusted merit order position of the interconnector price
$P_{i,old}$	Merit order position of the interconnector price
P_{tech}	Installed capacity of the current technology in the merit order
r_t	Revenue in time step t
S_{t-1}	State variable of the storage state in the previous time step
S_t	The sum of the storage state in time step t
x_i	Utilisation of interconnector i

Chapter 1

Introduction

1.1 Background

The United Kingdom (UK) is on a track of overhauling its energy system. Reforms already put in place and policies put forward, envision a greener, more secure, and a more cost-effective future British energy system. This sees the UK follow the global trend of trying to balance the requirements of the so called 'energy trilemma'. The energy trilemma seeks to achieve sustainable energy through three dimensions: energy security, energy equity (accessibility and affordability), and environmental sustainability (World Energy Council, 2016). To balance these three pillars there must be more generating capacity built in Great Britain (GB), while making sure that the new generating capacity does not pose a threat to the environment, and that the new capacity does not bring up wholesale electricity prices. Based on generation currently being built and the proposed plans for future build, the diversity and potential scarcity of supply, will both have a significant impact on the British wholesale electricity market. As of now, the lack of clear or seemingly achievable directives, has experts split on the direction of the wholesale price of electricity. A success story, seeing all the promised capacity built on time could result in similar or potentially even lower wholesale electricity prices and thus, as a result, lower end costs for the consumer (Helm, 2014), (Moody's Investors Service, 2016). On the other hand, failing to do so and not securing enough reliable capacity has the potential of tightening capacity and sending those prices up (BEIS, 2017i). In Great Britain, wholesale gas prices have been on the rise since the early 2000's due to upward pressure on prices in Europe and the decline of UK Continental Shelf gas production. Since natural gas is a key component of the British generation mix, wholesale electricity prices followed the trend of increasing natural gas prices. The observed increase in wholesale electricity prices is also tied to a rise from unsustainably low levels of coal prices, and the introduction of the European Union (EU) Emissions Trading Scheme (ETS) in 2005 (BEIS, 2017e). However, since the start of 2014, natural gas prices have been falling. The United Kingdom's decision to leave the EU has also impacted energy prices (Ward, 2016); however, the future of British wholesale electricity prices is now harder than ever to predict.

1.2 Motivation

In recent years, conventional power generation has been facing strong competition from renewable energy resources and other types of low-carbon technologies. In many European countries, such as Germany and the Nordic countries, renewable generation has become part of the mainstream energy mix. Deployment of renewable energy resources and their integration into the grid led to a decline in use of conventional thermal generation, which in many instances then led to power plant closures and now natural gas-fired power plants are a rare sight in Germany. In fact, the abundant renewable capacity in the energy system has occasionally even led to an oversupply of produced electricity (Starn, 2017). Great Britain, however, faces a different challenge as there are growing fears of electricity supply being insufficient in the coming years, exacerbated by the fact all coal-fired power plants must cease operation by 2025 (BEIS, 2017a). The British government has been determined to meet these shortages in supply by encouraging building additional natural gas-fired generation in order to replace generation being phased out; however, building targets are not being met on time (Institution of Mechanical Engineers, 2016). The demand for electricity has also been growing in the last few years as the country recovered from the economic strain caused by the financial crisis, which led to a decrease in electricity demand. The rest of energy supply is supposed to come from low-carbon resources, most notably renewable generation with the country primarily investing in wind and solar photovoltaic (PV) generation. Efforts have also been made to replace some of the ageing supply with new nuclear generation, however, projects like Hinkley Point C have proved to be a fiscal strain (National Audit Office, 2017). The commission date continues to be pushed further and further into the future, bringing along uncertainty and raising concerns if Hinkley Point C can actually be considered a stable source of energy supply for the British consumer. The uncertainty related nuclear technology brings about a variety of factors with a big impact on the future of energy generation of Britain. The issues arising from replacing the current generation with the new low-carbon generation can have a significant influence on the electricity market in the future and the resulting fluctuations in wholesale electricity prices in Britain.

1.3 Research question and scope

This research work aims to analyse the impact of low-carbon and smart grid technologies on the wholesale prices of the British electricity market. It highlights different types of generating technologies that already are or might be in the future a part of the British energy mix and the concurrent and consequent regulatory and commercial obstacles to an easy system-wide integration. The effect of bringing in different capacities of various novel generating technologies, such as renewable generation, is evaluated. The results are used to discuss necessary commercial and policy changes to improve the market performance and suggestions based on evidence from other countries is used to propose solutions for an improved British energy system.

The research question can be broken down into three objectives, which can be further broken down into subcategories:

1. Assessment of generation options
   - Assessment of various low-carbon generating and smart grid technologies and determining which ones will play an active role in the future British energy mix;
2. Modelling and simulation of costs
   - Merit order development with a case study based on National Grid's (NG) Future Energy Scenarios (FES) (National Grid, 2016b) from 2016 to simulate future wholesale electricity prices based on various types and capacities of renewable and thermal energy generation;
   - Determination of the effect of demand response (DR) on the British wholesale electricity prices and review of demand side management (DSM) policy in Great Britain;
   - Identification of the energy storage (ES) role in the British wholesale electricity market;
3. Policies
   - Study of the current energy policy state and future direction planned by the UK government and identification of necessary routes and incentives;
   - Review of the development of future British energy policy based on emissions targets, current build, future penetration of various technologies, and wholesale electricity price variations.

1.4 Original contribution

This thesis will test the hypothesis that:

> A wider variety of types of energy generation in the British energy mix and the inclusion of low-carbon and smart grid technologies in the energy system lead to improved security of supply and do not have an overwhelmingly negative long-term effect on the wholesale prices of the British electricity market.

The interdisciplinary work performed in this thesis differentiates itself from other long-term forecast models by offering a whole systems perspective on the future of the British energy. Unlike planning models, such as the UK TIMES (Daly and Fais, 2014), this model focuses on market operation and the long-term price consequences of integrating various low-carbon technologies into the British energy system. It differentiates itself from statistical models, which use historical prices for short-term and in some cases medium-term electricity price predictions. In terms of academic work, it offers an outlook on the development of future wholesale electricity prices in Great Britain. It focuses more on markets and less on operational and network characteristics.

The work presented in this thesis accounts for a variety of scenarios designed to try to predict the direction in which the British wholesale electricity market might head in the future. The work done here presents the upshot different low-carbon and smart grid technologies will have on the prices and argues in favour of their adaptation in the energy mix. Each scenario builds on the previous one and by doing so increases the complexity and validity of the model.

The work examines the causes of the biggest wholesale electricity market price fluctuations in Britain and what sort of policy and technology directives should be avoided or fostered. Past, current, and future energy policy is considered and attempts are made to predict how policy initiatives will impact the market in addition to the projected capacity built. Specifically this includes:

- Development of a merit order model to present the impact of different types of renewable energy generation technologies with varying degrees of capacity penetration. These technologies are: offshore and onshore wind, solar photovoltaic, tidal and wave, and biomass;
- Expansion of the same scenarios to see how the inclusion of varying degrees of renewable energy capacity operates within a system that is also equipped with demand side management and electrical energy storage (EES);
- Assessment of system and market performance following the application of electrical energy storage with the use of dynamic programming;
- Holistic review of all factors on the system and market after being studied individually and suggestions for expanding the work.

This research has generated four papers presented at major conferences in the field - European Energy Markets 2016, British Institute of Energy Economics Conference 2016, the 13th International Conference on Greenhouse Gas Technologies, and the 24th International Conference & Exhibition on Power Distribution Engineering; the thesis includes and examines the feedback received at these conferences and uses the feedback to improve the initial research. The dissemination of research can be found in Appendix A.

1.5 Thesis overview

This thesis consists of six chapters, which are described below:

Chapter 1 lays out the structure of the thesis, elaborates on the motivation behind the research work, and specifies the goals of the thesis.

Chapter 2 explains the current energy situation in Britain and details the factors that led to the current scheme. It begins with the deregulation of the electricity sector in the early 1990s under the Thatcher government, and trails the progress in transforming the energy generating sector from coal to natural gas to low-carbon technologies. Policy directives from the past and future are covered, such as the Electricity Market Reform (EMR) and the obligations Britain has to decrease its greenhouse gas (GHG) emissions. Current energy targets and policy schemes and their implication for the future of British energy system are discussed.

Chapter 3 offers a technology and policy review. First, renewable generation integration in Great Britain is studied and the policy that led to it becoming one of the components of the British energy mix. A similar review is performed for energy storage and demand side management and an outlook on the technologies' future development and importance in Great Britain is presented. The chapter concludes with a review of scenarios discussing the future of British energy.

Chapter 4 breaks down the entire electricity price forecast model and its sub-models to explain how they are used to simulate the future electricity prices. The data used for the model is referenced as are certain model decisions, such as plant availability, capacity factors, price caps, etc. Each section explains how each of the model components was integrated. The integrated components are renewable generation, interconnectors, energy storage, and demand side management.

Chapter 5 presents the results of the merit order model. The wholesale electricity prices are studied before and after energy storage is included, and the prices resulting from the implementation of demand side reduction, in addition to the consumer savings, are presented. Data used to simulate the results based on the case study is presented. The model and the results are validated.

Chapter 6 summarises the thesis by reviewing the results in a holistic way and by assessing the impact these prices would have on the market and policy in reality. The cogency of results is evaluated and suggestions for further work on the topic are made.

Low-carbon technologies currently relevant for British energy are included in the thesis - demand side management, energy storage, and all types of renewable energy generation. Notably absent from the low-carbon technologies included is carbon capture and storage (CCS). Recently, potential CCS projects were shut down in Great Britain and currently there is no proposed policy that might change that in the future (Gammer, 2016), (Energy and Climate Change Committee, 2014). Furthermore, a preliminary study using real options analysis (ROA) was carried out separately to determine the costs and thus possibilities of CCS inclusion in the British energy system and is detailed in (Lupo and Reiner, 2017).

Chapter 2

Electricity market in Great Britain

Great Britain is in the process of transforming the way its energy demands are met by shifting from conventional generation by accommodating the energy system to be better suited for low-carbon energy technologies. Renewable generation enjoys a majority support from the general public (Department of Energy and Climate Change, 2013c) and is, according to the government, the preferred method of electricity production for the future of energy generation in Britain. Yet, few steps have been made to ease this transition and the current energy picture seems to be keener on allowing for more natural gas-fired generation.

This chapter illustrates the development of the British electricity industry and reviews the factors and events that led to its current format and the development of the British electricity market as it functions today.

2.1 Pre-liberalisation

The British power system dates to the 1920s, when after the First World War the electricity supply in Great Britain was unreliable and expensive, which eventually led to the development of the national electricity transmission network. Although it remains the primary actor in the British power transmission sector and has been able to evolve with time to become the primary gas and electricity utility company, the same cannot be said about the current state of the power grid itself. The high voltage electricity transmission network is still owned and operated by NG but doubts have been raised about the network's readiness for incoming greener and smarter technologies as it has undergone barely any modernisation. As time went by, there was a change in the localisation of the centres of demand. Electricity generation became more advanced, yet little was done to modernise the grid as a whole, making it incompatible with technological advances, and thus unsuitable to answer the increases in demand.

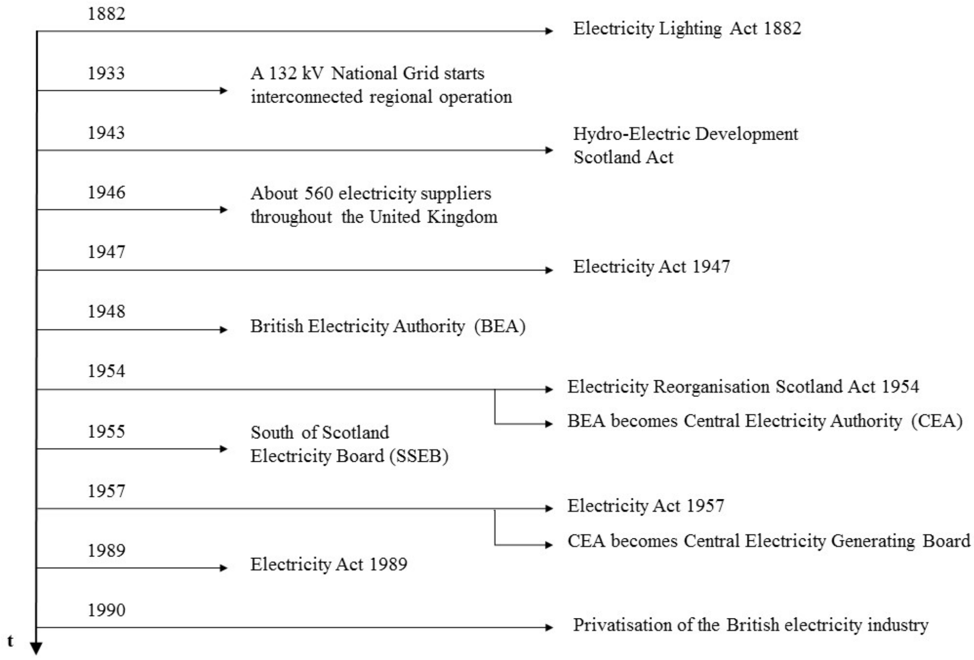


Figure 2.1: Timeline listing key historic events pre-privatisation responsible for bringing the British electricity industry to its current structure, based on (Simmonds, 2002)

2.2 Privatisation of the British electricity industry

Following a worldwide trend that arose in the 1980s, which pushed away from state-owned sectors towards liberalisation and deregulation, the British electricity industry was deemed salvageable only by privatisation (Gilbert and Kahn, 1996), which occurred under the Electricity Act 1989 (UK Government, 1989). The timeline of relevant events leading up to privatisation is broken down in Figure 2.1. In March 1990, the Central Electricity Generating Board (CEGB) ended and its assets were redistributed between four new companies, fuelling the start of a new industry structure in England and Wales. These four companies consisted of three generating companies: National Power and PowerGen, which were responsible for fossil fuel-fired plants, Nuclear Electric, responsible for nuclear generation, and one transmission company, National Grid Company (NGC). In addition to the transmission system, the NGC also operated pumped storage stations and interconnectors with Scotland and France. Distribution systems were managed by twelve regional electric companies (REC), which replaced the area boards under the CEGB (Simmonds, 2002).

Their position as public limited companies allowed National Power and PowerGen to sell 60% of their shares in 1991, while the remaining 40% was sold by 1995. Due to its high price, nuclear generation did not undergo privatisation until 1996 (Simmonds, 2002). REC shares began to be sold in 1990, however, the government kept the majority share up until 1995 (Newbery, 1995). Scotland soon followed suit and established ScottishPower and Scottish Hydro-Electric, which were to replace South of Scotland Electricity Board and the Hydro-Electric Board. The two companies were privatised in 1991. Nuclear generation was managed by Scottish Nuclear, which became a part of British Energy in 1996, and in 1998 Scottish Hydro-Electric merged with Southern Electric into Scottish and Southern Energy (SSE) (Simmonds, 2002).

2.2.1 Electricity trading

To trade wholesale electricity throughout England and Wales, an electricity pool was created, which enabled competitive bids from generators, and resulted in electricity prices in half-hourly periods. The CEGB merit order dispatch served as the guideline for the pool. The generators submitted their supply curve a day-ahead. Following the submission of the supply curve, the system operator (NGC) computed the least cost economic dispatch that met demand and assured all generators got paid the system marginal price. NGC was also in charge of making real-time adjustments for ensuring supply and demand were balanced (Simmonds, 2002). However, a decade into operation several problems were identified. PowerGen and National Power owned the bulk of the market share, which allowed them to set the spot price 90% of the time, and as a result there was a lack of competition in price setting. Demand side participation in the market was negligible and bidding arrangements were too convoluted. Additionally, producers with large market shares were able to withhold capacity by claiming a plant was unable to operate, resulting in unrepresentative price signals regarding long-term investment needs. Lastly, there was difficulty in interaction with the natural gas market, since gas trade occurred closer to real time, whereas electricity trading took place a day-ahead. The overwhelming problem was the lack of competition in the generation market, which was tackled by enabling new players to enter the market, however, plenty of the problems remained, which in 2001 led to the New Electricity Trading Arrangements or NETA (Simmonds, 2002).

2.2.2 Implementation of NETA and BETTA

NETA was developed to tackle problems arising in electricity pool operation by increasing the competition within the market. Forward and future markets and short-term power exchanges allowed for direct trading between generators, suppliers, traders, and consumers. ELEXON managed market operation and took on the role of the Balancing and Settlement Code Company (BSCCo) (Simmonds, 2002). Generators had to start determining their own output taking on what was previously NGC's role. Trades were no longer valued at the highest overall price bid but rather individually and trading went on until gate closure, making it possible for market actors to tailor their contracted positions more accurately. Capacity payment ceased in order to increase the role of demand side in the market. Finally, differences between physical consumption or production and contracted position at gate closure were settled through the balancing mechanism.

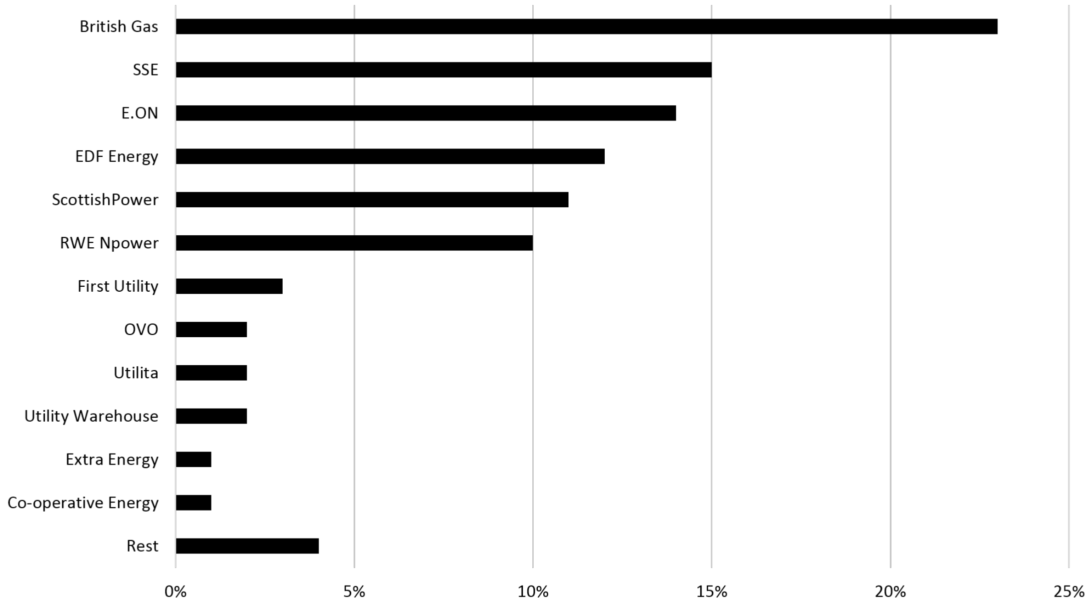


Figure 2.2: Shares of energy suppliers in Great Britain (Ofgem, 2016a)

In 2005, the electricity market of England and Wales merged with the Scottish electricity market and NETA was replaced by the British Electricity Trading and Transmission Arrangements (BETTA).

2.3 Structure of the current British electricity market

2.3.1 Generation

The current generation market comprises of six companies known as the 'Big Six', which all have largely integrated generation and supply business (Giulietti *et al.*, 2010). They are, listed from most to least market share: British Gas/Centrica, Scottish and Southern Energy, E.ON, EDF Energy, ScottishPower/Iberdrola, and RWE Npower. Their shares can be seen in Figure 2.2. About a quarter of the market share is distributed among other, smaller, generating companies with non-significant shares (Ofgem, 2016a).

Their majority market share makes it possible for the Big Six to form an oligopoly, making it incredibly difficult for new companies to enter the market. This market structure also makes the market susceptible to the main six actors abusing market power, colluding, and setting the prices (Percebois, 2008).

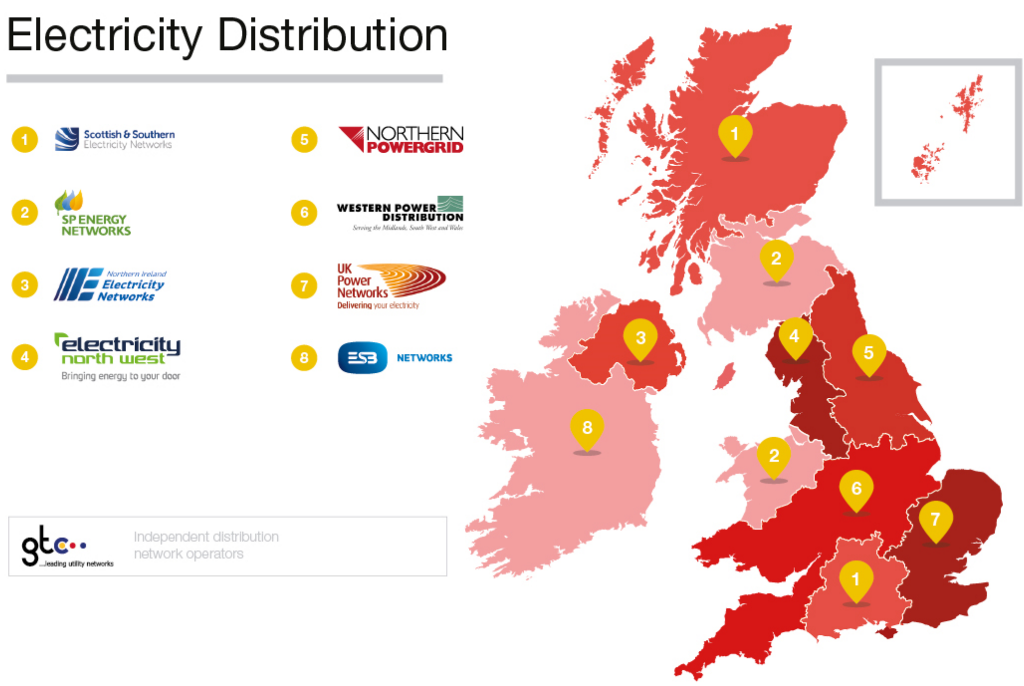


Figure 2.3: Map of DNO companies in January 2017 (National Grid, 2017b)

2.3.2 From transmission and distribution to supply

There are four main branches of the transmission industry. The offshore branch is made of many different assets and its construction falls under the administration of the Offshore Transmission Owners (OFTOs). Ofgem is responsible for selecting and licensing the OFTOs. National Grid Electricity Transmission (NGET) PLC solely owns the system in England and Wales, in addition to operating the entire transmission network. Scotland's transmission structure ownership is split between Scottish Hydro-Electric Transmission Ltd (SHETL), which owns the northern Scotland and Scottish Power Transmission Ltd (SPTL), which owns the southern Scottish regions (Simmonds, 2002).

Distribution network operators (DNOs) are responsible for the distribution service in their areas. There are 14 licensed DNOs in the UK. These companies are owned by six different organisations in GB and one in Northern Ireland in the regions shown in Figure 2.3 (National Grid, 2017b).

Distribution is the last step in bringing electricity to consumers' homes, since consumers are the ones to whom the final cost of the process is passed. Some of what final consumers pay to the electricity suppliers goes to the DNOs that are paid by the suppliers to transport electricity in the distribution services area network. In 2011, the 'Big Six' were responsible for supplying electricity to almost 100% of domestic customers, however, their share has fallen to about 86% by the end of 2016 (Ofgem, 2017k).

2.3.3 Market operation

Since electricity cannot economically be stored in large amounts, supply and demand must be matched at all times. In Britain, this task falls upon the suppliers, generators, traders, and customers trading in the competitive wholesale electricity market. Trading can be done on exchanges or bilaterally. Electricity contracts have varying time scales and they can range from on-the-day trading markets to multiple years. National Grid Electricity Transmission is in charge of balancing the electricity system and making sure that electricity supply and demand match on a second-by-second basis. NGET has a number of tools that it can use to do this, including the Balancing Mechanism.

2.3.4 The balancing services market

The ancillary or (balancing) services market allows NGC participants to pay for the option to buy energy at an agreed price, helping NGC in its obligation to keep the network in balance. Participants can be called on to provide generation or load-management capacity outside of stress events (van der Veen and Hakvoort, 2016). The market operates alongside the capacity and wholesale market (Engie UK, 2016).

2.4 Regulatory framework of the electricity market

The market privatisation brought along the necessity of regulating the electricity market and the Office of Electricity Regulation (OFFER) was established under the Electricity Act 1989 to smooth the process of privatisation and prevent any undesirable activities in the redesigned electricity model (UK Government, 1990). One of the main objectives of the Electricity Act 1989 was to facilitate competition and for that reason the framework made it a must to eliminate monopolistic activities from generation and supply. Thus, the Electricity Act 1989 made it impossible for companies operating under transmission or distribution licenses to also hold generation or supply licences. Although the necessary framework was put in place, it is still the case that some DNOs are owned by holding companies, which own supply and generation companies as well (Simmonds, 2002), (Hassan and Majumder-Russell, 2014).

2.4.1 Ofgem

One of the amendments to Electricity Act 1989 was the Utilities Act 2000, which not only modified Electricity Act 1989, but also Gas Act 1986, and Gas Act 1995. One of the most significant changes the Utilities Act 2000 brought was that it required that integrated electricity companies have separate licences for each of their business such as supply or distribution (UK Government, 2000). Intended as a successor to OFFER, the Utilities Act 2000 introduced

Ofgem, which was set up as the gas and electricity market regulator to prevent market irregularities and unlawful operation. The governing body of Ofgem is the Gas and Electricity Markets Authority (GEMA), which oversees the work done by Ofgem and provides it with strategic direction (Ofgem, 2017a). Ofgem was set up by keeping consumer welfare and rights in mind, which should be maintained and respected 'through promotion of value for money, security of supply and sustainability, for present and future generations' (Ofgem, 2014).

2.4.2 Department of Energy and Climate Change to Department for Business, Energy, and Industrial Strategy

The Department of Energy and Climate Change (DECC) was established in 2008 by then prime minister Gordon Brown to aid in development and implementation of policies related to energy and climate change. The current prime minister, Theresa May, dissolved DECC in 2016 and merged DECC with the Department for Business, Innovation and Skills, to form the Department for Business, Energy and Industrial Strategy (BEIS) (UK Government, 2016d), (UK Government, 2017c).

2.5 Global, European and British energy directives and initiatives

Britain's energy ambitions and goals are heavily interlinked with those of the EU, which in turn, usually go along with global ambitions for negating the harmful effects of greenhouse gas emissions.

In December 2015, the UK joined 197 countries in signing an historic global deal to tackle climate change. The Paris Agreement commits the international community to reduce greenhouse gas emissions to avoid some of the most severe impacts of climate change (UK Government, 2017b). This is to be achieved with countries agreeing to work together to limit global warming to less than two degrees Celsius compared to pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5 degrees Celsius. Additionally, the agreement aims to strengthen the ability of countries to deal with the impacts of climate change (United Nations, 2015).

The UK continues to reduce its emissions. In 2015 UK emissions were 38% below their 1990 levels (Committee on Climate Change, 2016).

2.5.1 Climate change legislation in the EU

Reducing emissions across the EU

The EU pledged to three targets for 2020:

1. Emissions reduction by 20% based on 1990 levels;
2. Provision of 20% of its total energy from renewable energy resources;
3. A 20% increase in energy efficiency based on 2007 levels.

Additionally, European leaders have endorsed an 80-95% reduction by 2050, also based on emissions levels from 1990. Various low-carbon roadmaps have been developed to demonstrate the most likely ways in reaching this target (Committee on Climate Change, 2017a).

The European initiatives for greenhouse gas reduction are a part of the 'Europe 2020 Strategy'. It includes the headlining targets of the EU's new strategy for smart, sustainable, and inclusive growth. Member States are required to set national targets in close dialogue with the European Commission (EC) and to indicate, in their National Reform Programmes, how they intend to achieve them (European Parliament, 2012).

European initiatives for greenhouse gas reduction

- EU Emissions Trading System (EU ETS) - the purpose of EU ETS is to cap overall emissions from power stations and industry sectors with high levels of emissions in addition to decreasing the cap every year. The cap allows companies to 'trade' emissions by purchasing and selling emission allowances as required. The cap-and-trade approach to emissions reduction is highly flexible, while ensuring emissions are cut in the most cost-effective way. It includes more than 11,000 power stations and industrial plants across the EU with around 1,000 of these in the UK. The EU cap will reduce the number of available allowances by 1.74% each year, delivering an overall reduction of 21% below 2005 verified emissions by 2020 (BEIS, 2013a). The UK is the second largest emitter of greenhouse gases in Europe (Matthews *et al.*, 2014); however, after the British vote to leave the EU, doubts have been expressed whether or not the UK will stay within the European carbon market, since it will technically have no say on its future developments (Doda *et al.*, 2017).
- Renewable Energy Directive (RED) - RED or the Renewable Energy Directive 2009/28/EC, which began in 2009, aims to increase renewable energy capacity throughout the EU, fostering the development of biomass, offshore and onshore wind, solar power, hydropower, and geothermal energy, by setting targets for the percent of energy generated by renewable resources. It applies to heat and transport, as well as electricity. The 2009 Renewable Energy Directive sets a target for the UK to achieve 15% of its energy consumption from renewable sources by 2020. This compares to only 1.5% in 2005 (Department of Energy and Climate Change, 2009). The current EU emissions targets

are a 40% cut by 2030, while the UK government's goal is to cut emissions by at least 35% in 2020, 50% by 2025, with an 80% target set for 2050, all below 1990 levels (Department for Energy and Climate Change, 2015a). Overall, the UK has already met its 2020 emissions target since the reduction in emissions has surpassed the desired 35%.

- Energy Efficiency Directive (EED) - developed in October 2012, the EED sets frameworks for ways to advance energy efficiency across the EU and reach a 20% energy efficiency target by 2020, and a 30% target by 2030. The European Commission maintains a new energy efficiency strategy is necessary for all Member States to decouple energy use from economic growth (European Parliament, 2012).
- New car and van CO_2 targets - the EU has implemented legally-binding targets for the level of emissions allowed from new cars and vans to achieve a reduction in emissions resulting from road transport (European Commission, 2009). France and the United Kingdom have banned sales of diesel and petrol cars starting in 2040 (Chrisafis and Vaughan, 2017), (DEFRA and Department for Transport, 2017), and Slovenia plans on banning the registration of fossil fuel cars from 2030 on (Novak, 2017). Non-EU country Norway has the goal to reach 100% of new car sales being zero-emission vehicles starting in 2025 (Staufenberg, 2016).
- Carbon capture and storage - the EU promotes the development of CCS technology in order to catch and store harmful emissions originating from power stations and other major industrial installations (Global CCS Institute, 2013).
- 2030 Climate Framework - the 2030 Climate Framework was proposed to help propel greenhouse gas reduction until the year 2030 and establish plans for a low-carbon economy for years after 2020 (Committee on Climate Change, 2017a).
- The Large Combustion Plant Directive (LCPD) - issued in November 2001, the LCPD is the Directive 2001/80/EC on the limitation of emissions of certain pollutants into the air from large combustion plants of the European Union. The LCPD was put in place in order to reduce emissions of acidifying pollutants, particles, and ozone precursors. Control of emissions from large combustion plants - those whose rated thermal input is equal to or greater than 50 MW - plays an important role in the EU's efforts to combat acidification, eutrophication and ground-level ozone as part of the overall strategy to reduce air pollution. Plants built before 1987 were given the choice between observing the limits or not participating. If they chose not to observe the limits set by the LCPD, they were limited to a maximum of 20,000 hours of operation after 2007 and required to close by 2015 (European Commission, 2001).

  It has since been superseded by the Industrial Emissions Directive (IED) on January 1st, 2016. The IED aims to achieve a high level of protection of human health and the environment taken as a whole by reducing harmful industrial emissions across the EU, in particular through better application of Best Available Techniques (BAT) (European Council, 2010).

2.5.2 British green ambition

As a current member state of the EU, the UK is actively encouraged to take appropriate measures in tackling global climate change. This is achieved by introducing targets for emissions, efficiency, and renewable energy development.

The Climate Change Act of 2008

In 2008, the UK government passed the Climate Change Act (CCA) (UK Government, 2008) and set up a framework to bring into being an economically plausible emissions reductions path. It brought forth the UK's leadership position on the international scale by pointing out the key role the UK would take in contributing to the joint mission to tackle climate change under the regulations of the Kyoto Protocol. The Kyoto Protocol is an international agreement linked to the United Nations (UN) Framework Convention on Climate Change, which commits its Parties by setting internationally binding emission reduction targets. Recognizing that developed countries are principally responsible for the current high levels of green house gas emissions in the atmosphere as a result of more than 150 years of industrial activity, the Protocol places a heavier burden on developed nations under the principle of 'common but differentiated responsibilities' (United Nations, 1998).

The CCA consists of the following:

- The Committee for Climate Change (CCC)
  The CCC was set up to provide guidance and advice to the UK government on emissions targets but also provide reports and updates on the progress made on reducing greenhouse gas emissions. The Adaptation Sub-Committee is a part of the CCC and its role is to examine, monitor, and to give counsel on the Government's programme for adapting to climate change.
- The 2050 Target
  The 2050 Target binds the UK to a reduction of greenhouse gas emissions by at least 80% in 2050 based on 1990 levels. The target number was proposed in a report, named Building a Low-carbon Economy, written by the CCC (Committee on Climate Change, 2008). The 80% target put forward for consideration is inclusive of the greenhouse gas emissions from the devolved administrations that currently account for approximately 20% of total emissions of the UK.
- Carbon Budgets
  The CCA mandates that the UK government sets legally binding 'carbon budgets'. A carbon budget is the maximum amount of greenhouse gases that can be emitted in the UK over a period of five years. The UK is the first country to set legally binding carbon budgets. By publishing these carbon budget reports the CCC aims to provide guidance on the feasible level of each carbon budget. All carbon budgets are formulated in a way that they represent reasonable and cost-effective paths towards obtaining the long-term

objectives. The first five carbon budgets have already been put into legislation and run up to the year 2032 (Committee on Climate Change, 2017a). The Government has agreed with the CCC and set the fifth budgetary period covering 2028 to 2032 at 1,725 Mt CO_2e (mega-tonnes of carbon dioxide equivalent), which includes emissions from international shipping. The fifth carbon budget limits annual emissions to an average 57% below 1990 levels (Hoskins *et al.*, 2016). The budget requires a continuation of the increase in take-up of ultra-low emission vehicles (e.g. electric and plug-in hybrid cars and vans) and low-carbon heat (e.g. heat networks and heat pumps) required by the fourth carbon budget. These changes will require bigger behavioural adjustments than emissions reductions to date, but are needed to prepare for the 2050 target. To involve genuine emissions reductions, they should be accompanied by deep reductions in emissions from electricity generation.

- The National Adaptation Programme
  The National Adaptation Programme (NAP) is crucial for assessing the risks from climate change the UK might face. It does so by preparing a strategic approach to address them and works with critical organisations and urges them to follow the same approach (Committee on Climate Change, 2017a).

British government and climate change

Preventing and preparing for the harmful repercussions of climate change has implications for every aspect of the economy. There are many governmental departments dealing with climate change and the two key departments charged with providing input and setting climate change policies are BEIS and the Department for Environment and Rural Affairs (DEFRA).

- DECC and BEIS
  The department brings together responsibilities for business, industrial strategy, science, innovation, energy, and climate change. DECC was responsible for the development and formulation of the Climate Change Act 2008. Following on from DECC, BEIS is the UK's leading actor on policy for the reduction of harmful emissions. It is BEIS's responsibility to deliver secure energy and drive progressive action on climate change on the national and international scale (UK Government, 2017c). DECC oversaw formulating the Energy Act 2011, which had three principal objectives: tackling barriers to investment in energy efficiency, enhancing energy security, and enabling investment in low-carbon energy supplies (UK Government, 2011). In 2012 another Energy Bill was introduced to the UK Parliament, which received Royal Assent in December 2013 and became the Energy Act 2013. The Act covered the areas of decarbonisation, nuclear regulation, the sale of the government pipeline and storage system, and consumer protection. Lastly, the Act introduced the policy of Electricity Market Reform, which ought to have a significant impact on the functioning and structure of the British electricity market (UK Government, 2013b).

DECC, with the help of Her Majesty's Treasury, was behind the design and implementation of the Government's Levy Control Framework (LCF). The LCF is a cap introduced to determine the highest amount of spending available in the period 2014/15-2020/21 through consumer bills to support Government's electricity market decarbonisation and renewables objectives. The LCF was implemented by setting an annual limit on the overall costs for different schemes, such as the Renewables Obligation (RO), small-scale Feed in Tariffs (FiT), Investment Contracts, and Contracts for Difference (CfD). The amount of the LCF allocated for each scheme is described as a 'budget'. In July 2015, the Office of Budget Responsibility (OBR) announced the spending forecast under the LCF to 2020/2021 of £9.1 billion, in 2011/2012 prices, pushing the spend on renewable energy subsidy schemes higher than it was initially anticipated. The higher spend was said to be due to accelerated developments in technological efficiency, higher than expected uptake of demand-led schemes, and changes in wholesale prices. The Government has chosen to tackle higher costs under the LCF by introducing early closure for the onshore wind scheme and the small-scale solar scheme and announcing caps for future FiT spending (Department of Energy and Climate Change, 2014b). In the Spring 2017 budget, the Chancellor of the Exchequer, Philip Hammond, revealed that the LCF will come to an end and will be replaced by a new set of controls by the end of 2017. The new set of rules will apply to projects after 2020/2021, when the LCF officially expires (HM Treasury, 2017).

- DEFRA

  DEFRA's roles include safeguarding the natural environment, supporting the food and farming industry, and sustaining a thriving rural economy (UK Government, 2017a). DEFRA was responsible for the development of the National Adaptation Programme (DEFRA, 2013a) which deals with the task of ensuring the government, businesses, and society are actively trying to become more climate ready. This programme is developed by the Government as a joint effort with businesses, local governments, civil society, and public sector organisations. The NAP report was published in July 2013 and the next five year review is due in the summer of 2018 (UK Government, 2013a). Together with the CCC, DEFRA brought forth the issues set out in the Climate Change Risk Assessment (UK Government, 2017b), which is an assessment of the risks and opportunities for the UK of the current and predicted impact of climate change. The last report was published in January 2017 and sets out the six priority risk areas requiring further action in the UK over the next five years.

  However, although both DECC/BEIS and DEFRA, consistently argue in favour of the implementation of measures helping to curb harmful effects of global warming, they were also involved in the conception and design of the Infrastructure Act 2015 under the primary supervision of the Department for Transport. The Act, which became law in 2015, targets transport, energy provision, housing development, and nationally significant infrastructure projects (UK Government, 2015a). Although the legislation has some potential benefits such as making it possible for local communities the right to buy a stake in renewable energy projects, it has been the subject of controversy since it allows for hydraulic fracturing or 'fracking'. The Act makes land exploitation for petrol or deep geothermal energy possible without informing the land owners, negating the need for an agreement to access such resources.

- <u>Devolved Administrations</u> (DAs)
  There is a role to play for DAs by developing climate change policy in devolved policy areas in addition to aiding in the implementation of country-wide policies. DAs are covered by the UK CCA but they also advance their own climate change policies, such as:
  - The Climate Change (Scotland) Act, which was passed in 2009, and commits Scotland to a 42% reduction on emissions by 2020 and 80% by 2050, based on 1990 levels (Scottish Parliament, 2009). Scotland already passed its 2020 commitment six years ahead of the target and in 2014 a reduction of 45.8% has been achieved (Scottish Government, 2016b). The Scottish Government has announced, as part of A Plan For Scotland: The Scottish Government's Programme For Scotland 2016-17, that it will bring forward a new Climate Change Bill, including an ambitious new 2020 target for reducing Scottish emissions by more than 50% (Scottish Government, 2016a). In January 2017, it was announced that Scotland plans to cut emissions by 66% based on 1990 levels by 2032 (United Nations Climate Change, 2017). Additionally, following the Westminister pledge to ban diesel and petrol car sales by 2040, the Scottish government brought the date forward to 2032 for Scotland (Khan, 2017).
  - Development of plans for a Northern Ireland (NI) Climate Change Act. NI's target is to reduce emissions by 35% on 1990 levels by 2025 (Department of Environment - Northern Ireland, 2014).
  - The Welsh government is considering the implementation of potential options for the changes to the climate change legislation of Wales, such as setting its own carbon budgets (Committee on Climate Change, 2017b).

2.6 Electricity market reform

The next big change in British electricity market regulation came with the Electricity Market Reform for which the consultation began in December 2010 (UK Government, 2010). A two-year consultation period resulted in the Energy Bill being introduced to the UK Parliament in November 2012 and receiving Royal Assent in 2013 (UK Government, 2013b). The major driving force behind the EMR was trying to meet the demands of the energy trilemma (Department of Energy and Climate Change, 2011b). The reform consists of changes to the environmental tax and subsidy arrangements as well as changes to the market design. The aim of the reform is to deliver secure power, renewables, and carbon reduction simultaneously. The desired result of the EMR is to effectively end competitive investments and replace it with a system of administered energy and capacity prices (Pollitt and Haney, 2013).

2.6.1 Key EMR elements

The EMR consists of four key elements:

- Contracts for Difference
- Carbon Price Floor/Carbon Price Support (CPF/CPS)
- Emissions Performance Standard (EPS)
- Capacity Market (CM)

Fixed prices for low-carbon generation (based on contracts for difference around feed-in tariffs, or CfD-FiT)

A CfD is a contract between a low-carbon electricity generator and the Low Carbon Contracts Company (LCCC), a Government-owned company. A generator party to a CfD is paid the difference between the 'strike price' - a price for electricity reflecting the cost of investing in a particular low-carbon technology - and the 'reference price' - a measure of the average market price for electricity in the GB market. For renewable energy generators CfDs allow for improved certainty of revenues, since they decrease their exposure to volatile wholesale prices. As low-carbon generators generally have high capital costs but almost no operating costs, they are exposed to this volatility more compared to fossil fuel-fired generators, which serve as price setters. The CfD mechanism also protects end consumers from paying for higher support costs when electricity prices are high. This is because the cost of CfDs will be met by consumers via the supplier obligation, a levy on electricity suppliers. The CfD mechanism is available to nuclear, CCS, and renewable energy projects.

The CfD allocation round begins with BEIS's budget, which is provided ahead of time to NG as the EMR Delivery Body. This budget sets the overall funding cap and includes other constrains for particular low-carbon generation technologies targeted by BEIS. Following this eligible generators may then submit multiple applications for various projects to the Delivery Body, and an auction will be called if the applications collectively exceed the budget in any delivery year. The Delivery Body then allocates the projects to generators according to the results of the auction, trying to allocate CfDs to projects with lowest costs and in a broadly technology-neutral manner. If the total value of applications doesn't exceed the available budget, all accepted projects will receive the technology-specific strike price set by BEIS (Fitch-Roy and Woodman, 2016).

Table 2.1: Strike price for projects commissioning in the year stated in the column

	Strike Prices £/MWh (2012 prices)				
	2014/15	2015/16	2016/17	2017/18	2018/19
Advanced Conversion Technologies (with or without CHP)	155	155	150	140	140
Anaerobic Digestion (with or without CHP)	150	150	150	140	140
Dedicated Biomass (with CHP)	125	125	125	125	
Energy from Waste (with CHP)	80	80	80	80	80
Geothermal (with or without CHP)	145	145	145	140	140
Hydro	100	100	100	100	100
Landfill Gas	55	55	55	55	55
Sewage Gas	75	75	75	75	75
Onshore Wind	95	95	95	90	90
Offshore Wind	155	155	150	140	140
Biomass Conversion	105	105	105	105	105
Wave	305	305	305	305	305
Tidal Stream	305	305	305	305	305
Large Solar Photo-Voltaic	120	120	115	110	100
Scottish Islands Onshore				115	115

From the perspective of auction participants the relevant features of the CfD auction process are as follows (BEIS, 2017b), (BEIS, 2017c):

- Eligible generators submit a bid for each application, which are then ranked from lowest to highest strike price;
- Bids are accepted sequentially, starting with the bids with the lowest strike price, and subject to the budget constraint;
- Projects are approved in this way until that delivery year's budget is met;
- When the auction closes, all projects within that delivery year are awarded a final clearing price equal to the strike price of the last approved project.

The outcomes of the first auction were particularly favourable for onshore wind (Department of Energy and Climate Change, 2015a). The predicted maximum strike prices until 2018/2019 can be seen in Table 2.1 (Department of Energy and Climate Change, 2013d). These prices are in all cases maximum strike prices.

The application process for the second CfD allocation round opened in April 2017. The second allocation round is intended for less established technologies: offshore wind, Advanced Conversion Technologies, Anaerobic Digestion (>5W), Dedicated biomass with Combined Heat and Power (CHP), and wave, tidal stream and geothermal projects starting to generate from 2021/22 or 2022/23 (UK Government, 2016a).

As of March 31st 2017, the CfD mechanism has completely replaced the Renewable Obligation mechanism, which closed to all new generating capacity. The RO came into effect in 2002 in England, Wales, and Scotland, followed by NI in 2005. It placed an obligation on UK electricity suppliers to source an increasing proportion of the electricity they supply from renewable sources (Ofgem, 2017b).

The EMR Delivery Plan will be published every five years and will set out the maximum strike price that can be included in CfDs, which will determine the maximum level of support for low-carbon technologies. The first EMR Delivery Plan was published in December 2013 and included the administrative strike prices for renewable technologies for CfD commissioning during the period 2014/15-2018/19 (Department of Energy and Climate Change, 2014b).

Carbon price floor and carbon price support

Beginning with 2005, the carbon price was set by the market under the EU ETS, which allowed for carbon emission allowances to be created and distributed. The allowances were traded between companies, which resulted in a traded price for carbon. But the oversupply of allowances made it impossible for the price to increase (Carbon Trust, 2007). Following this, the CPF came into action in April 2013 and set a minimum price of carbon in the British electricity generation market by taxing the fossil fuels that are used to generate electricity under the Climate Change Levy (CCL), in the case of gas, solid fossil fuels and liquefied petroleum gas (LPG), and fuel duty, in the case of certain oils (notably fuel oil and gas oil) (UK Government, 2013c). The CCL was introduced on April 1, 2001, under the Finance Act 2000 as a tax on energy delivered to non-domestic consumers. The CCL is broken into two rates:

- Main rate, which must be paid for supplying business customers with electricity or fossil fuels, which exclude oil, which is covered by fuel duty;
- CPS rate, which must be paid for generating electricity by using fossil fuels, excluding oil (UK Government, 2014c), (UK Government, 2014b).

The CCL will increase from April 2019 to cover the shortfalls in revenue caused by the closure of the Carbon Reduction Commitment (CRC) Energy Efficiency Scheme. The CRC Scheme was mandatory reporting and pricing scheme aimed to achieve better energy efficiency in large public and private organisations (UK Government, 2014a). The CPS is calculated annually using the two-year forward predicted price of EU Emissions of CO_2 relative to the rest of Europe (Pollitt and Haney, 2013). However, in Budget 2014 the Government announced that the CPS component of the floor price would be capped at a maximum of £18 per tonne/CO_2 from 2016 to 2021 to limit the competitive disadvantage faced by business and reduce energy bills for consumers. This was extended to 2021 in Budget 2016 (Ares and Delebarre, 2016). Further, questions were raised, when there was no mention of the CPF in the Spring 2017 budget and no information was provided about the future of it. The CPF decision was delayed until the Autumn budget (HM Treasury, 2017).

Emissions performance standard

The EPS is intended to limit carbon dioxide emissions from new fossil fuel power stations by setting an annual limit on carbon emissions from new fossil fuel-fired power stations; however, it does not apply to new biomass-fired plants or to energy from waste. The EPS states that no new coal-fired power plant can be built without CCS technology. The reform proposes a standard of 450g CO_2/kWh. However, new supercritical coal-fired generation has average CO_2 emissions of around 790 g/kWh and a modern gas-fired power plant averages around 360 g/kWh, which makes the coal-fired power plant undesirable to be built in these conditions. Yet, there remains another possible use for the reform as it could be used to eliminate new natural gas-fired power plants in the future should the first three elements of EMR fail to support the decarbonisation of the electricity sector. The EPS is calculated as the maximum emissions to be produced at a power station assuming an 85% annual load factor. This implies that a peaking open cycle oil or gas plant would be allowed, as would a two-unit supercritical coal-fired plant with CCS fitted to just one of the units (Pollitt and Haney, 2013).

Capacity market

The CM is set to commence operation in 2018 and ensure sufficient investment in the overall level of reliable capacity, from both the supply and demand side, which is necessary for the security of electricity supply. The CM will operate alongside the current energy market, which is already supported by the balancing services market. To maintain sufficient and reliable capacity, the CM employs the services of load-management and generation, to meet peak demand, for example, during cold, still periods where demand is high and wind generation is low. The CM operates by giving generators a fixed monthly payment to ensure enough capacity is in place to meet demand.

More and more intermittent generation is coming on stream and it is the task of the CM to provide back-up generators and demand side responders to help balance the network at times of stress. This capacity must be available when providers are called upon by NGC at any time during the contracted period and failing to do so results in penalties for the providers. Investment is fostered by allowing the market to competitively set a price for capacity as the participants are paid a per MW rate for the capacity they offer to the market. Capacity agreements are offered to investors in existing and new capacity four years ahead of the year when capacity must be delivered, giving them certainty regarding future revenues and helping them recover investment costs not recoverable through the energy market (Department of Energy and Climate Change, 2014b), (Engie UK, 2016).

The most recent capacity auction concluded on December 8, 2016, clearing at £22.50/kW/year, slightly higher than in previous years, securing 52.4 GW of capacity for delivery in 2020/21, representing a gross cost to consumers of around £1.2 billion in the first year. Most capacity was awarded to existing generating technologies, such as combined cycle gas turbines (CCGT), which received the majority of capacity agreements, and also nuclear and coal/biomass. However, out of about 8 GW of new CCGT capacity participating in the auction, only one plant was successful.

In the past auction, heavily polluting small-scale diesel generators won a lot of contracts. However, the attempts of BEIS and Ofgem to reduce this were successful since this auction resulted in only a few diesel generators being awarded contracts. Around 500 MW of new-build battery storage was successful in ensuring capacity agreements, in addition to over 1.4 GW of demand side management (Virley *et al.*, 2016), (National Grid, 2016a).

2.7 Outlook

In addition to different reforms intended to restructure the market, the infrastructure goals include an increased number of natural gas-fired power plants to compensate for coal-fired power plants on their way out by 2025. The modernisation of the grid to accommodate for the conventional power plant operation in union with intermittent low-carbon generation requires paving the way for a smart grid.

The definition of the smart or the integrated grid varies but is commonly regarded as the next generation power grid, which uses two-way flows of electricity and information to create a widely distributed automated energy delivery network (Fang *et al.*, 2012). The smart grid consists of additions to the normal power grid, which aim to increase the grid's flexibility and security. These additional agents can be electrical energy storage, distributed generation, electric vehicles (EVs), DSM, and even renewable generation.

2.8 Chapter summary

In this chapter the development of the British energy infrastructure and wholesale electricity market is presented. First, the events that led to the privatisation of the electricity industry were presented, followed by a more detailed look into some of the policy and regulation. The structure of the British electricity market was presented by describing the role of each of its components. Discussing the regulatory framework of the market led to the introduction of domestic, European, and world-wide initiatives for tackling climate change and developing more flexible low-carbon power systems. Various European initiatives aiming to reduce greenhouse gas were described in detail. Following that some individual domestic initiatives, separate from the EU ones were presented, alongside different programmes, departments and corresponding regulation. The last part of the chapter discusses the Electricity Market Reform and its components, which are intended to change and improve the operation of the British electricity market. The next chapter looks into different types of low-carbon technologies and their development in Great Britain.

Chapter 3

Technology review

This chapter reviews the technology and policy decisions behind the three biggest low-carbon technologies - renewable generation, energy storage, and demand side management. The key energy and climate change policies that allowed low-carbon technology progress so far are discussed and the future decisions in policy making that could make a difference in improving the development of the low-carbon technologies are presented. Finally, a review of different scenarios describing the future of British energy based on the past, present, and likely future policies is included.

3.1 Renewable generation

With the introduction of different types of variable renewable energy sources, generators and other actors in the electricity market are faced with a new layer of complexity they have to adapt to. This upsets the electrical consumption profile that power generation production has mostly followed and the established merit order, which was assumed on the basis that power generators bid their short-run marginal costs (SRMC). Different types of renewable generation that will be among those having the largest impact on the electricity prices and the overall energy picture of Great Britain are reviewed. These are wind power, solar photovoltaic power, marine power, hydroelectric power, and biomass generation (National Grid, 2016b).

3.1.1 Current state

Electricity generation in Britain in 2016 consisted of mainly gas (42.4%), renewables (24.4%), nuclear (21.2%), coal (9.1%), and oil and other (2.9%) (BEIS, 2017f).

Renewable electricity generation was 82.8 TWh in 2016, a fall of 1.0% on the record 83.6 TWh recorded in 2015. Offshore wind generation fell by 5.8% and onshore wind by 7.8%, with average wind speeds (at 8.3 knots) 1.0 knots lower than the high wind speeds of 2015 (the highest in the last fifteen years). Generation from solar photovoltaics increased by 36%, to a record 10.3 TWh, due to increased capacity. Hydro fell by 15% compared with 2015's record level, to 5.4 TWh, with average rainfall (in the main hydro areas) down by 19% on a

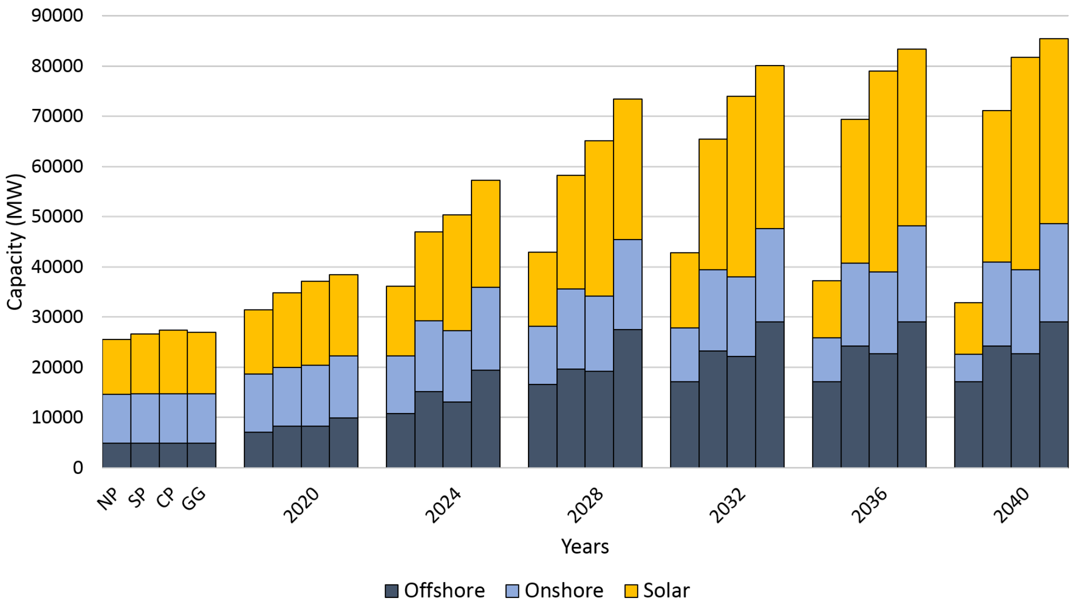


Figure 3.1: Growth of intermittent renewables from 2016 to 2040 (National Grid, 2016b)

year earlier. Generation from bioenergy was up slightly on 2015, with additional capacity being partially offset by maintenance outages at the converted Drax biomass units and the closure of Ironbridge in late 2015. Renewable electricity capacity was 34.7 GW at the end of 2016, a 14% increase (4.2 GW) on a year earlier (BEIS, 2017f).

In the coming years, Britain will continue to decarbonise the economy to tackle climate change and to meet its legally-binding renewable energy targets with the first target coming up in 2020. In countries where the addition of renewables to the generation mix changes marginal costs, electricity prices decrease following the decrease in demand from thermal plants; this is the current situation in Germany (Bublitz *et al.*, 2017). Electricity prices are rather low because a significant amount of wind and solar capacity has been added, lowering the profits of generating companies. In the long term, generating companies respond to lower profits by closing down power plants, which has the impact of sending those prices back up, although not to their initial levels. Adding renewables results in lower electricity prices but in time one would expect the capacity to adjust such that similar price patterns as before are observed. This allows one to look at countries' energy profiles in the short term and over a longer period after the capacity has adjusted; this then pushes for additional research into what kind of capacity should be built.

The growth of intermittent generation as assumed by National Grid's Future Energy Scenarios from 2016 to 2040 is in Figure 3.1.

The goal is to find the best way to move forward with renewable technology operation in Britain, keeping wholesale electricity prices within reasonable limits to avoid significant fluctuations in wholesale electricity prices at the time, while maintaining uninterrupted electricity supply to all consumers. To avoid large electricity price fluctuations for the time being, as renewable capacity has not reached a point where it can completely replace conventional generation, we rely on thermal generation to provide us with more consistent prices. However, in the future scenarios, discussed later in the chapter, the ambition is that renewable energy generation will be able to not only maintain current price patterns, but also reduce wholesale electricity prices, in the next decade or so.

Compared to overall conventional generation, there is limited renewable capacity in Britain and until more cost-effective ways of renewable generation can be developed, renewable capacity will be costlier. Most renewable generation, with the exception of biomass, is non-dispatchable due to its fluctuating nature and might not be able to handle sudden surges in demand so it is important to continue relying on conventional generation at least for now. This section aims to demonstrate what sort of capacity of renewable energy in addition to the established conventional energy generation would allow Britain to maximise the energy potential renewables bring to the energy mix, while minimising investment risk of technologies that might not contribute the value of the cost to the generation scheme.

3.1.2 Wind energy

Wind energy has been making a contribution to the British energy generation mix for a number of years and at the end of April 2017, wind power in Britain had a total operational capacity of over 15.4 GW (RenewableUK, 2017). Of that 10,094 MW came from onshore wind and 5356 MW came from offshore wind. The historical wind capacities documenting the technology's growth every year from 2011 to 2015 are in Figure 3.2. The corresponding combined total wind generation during each year for the same years follows in Figure 3.3. The figure goes to show how wind generation varied in each specific year. For example, for the year 2015, the wind generation was 7000 MW or more for 8760 - 8000 hours, meaning this wind generation capacity was more than 7000 MW or more for only 760 of the 8760 hours of the year.

Offshore wind is an ideal technology for Britain, where the shallow seas and strong winds make it an important national asset. As offshore wind becomes a more mature technology and costs fall, it has the potential to play a very significant role in the 2020s and out to 2040.

Onshore wind generation is already cheaper than gas and coal-fired generation when external health impacts such as air quality, human toxicity, and climate change are factored in (Alberici *et al.*, 2014) however, there is some uncertainty regarding the policy for onshore wind power in Britain. In June 2015, the previous government under prime minister David Cameron announced subsidies for new onshore wind farms were to end in April 2016, a year sooner than intended in the previous government coalition agreement. A grace period was determined for projects which already had planning permission (Department for Energy and Climate Change, 2015b). Power was passed down from the national government to local communities by giving them the right to veto wind farms. Planning tests were initiated with the idea of giving only the

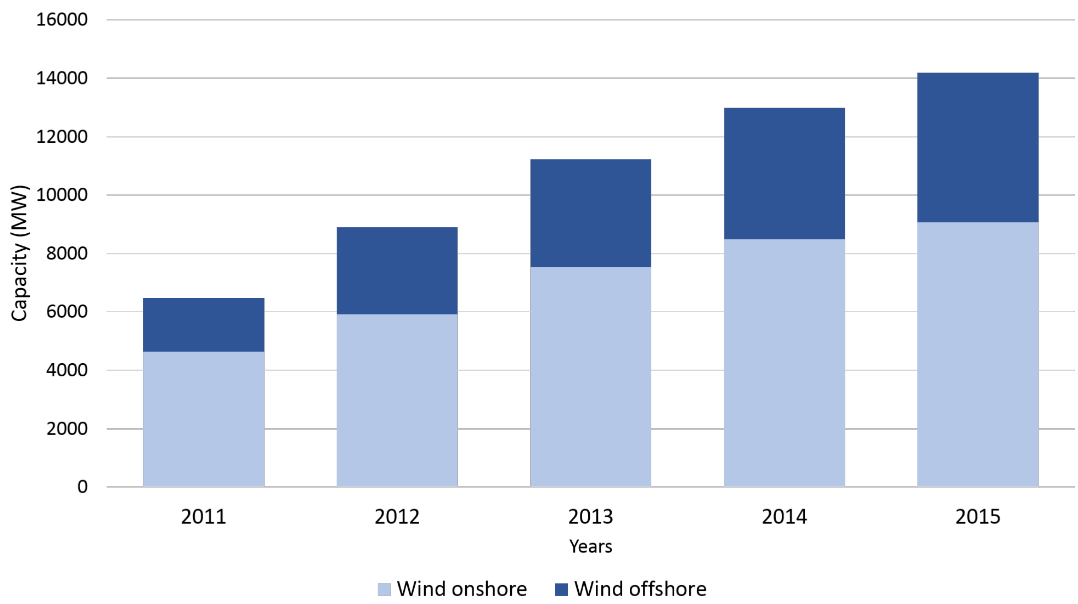


Figure 3.2: Total installed wind capacity from 2011 to 2015 (RenewableUK, 2017)

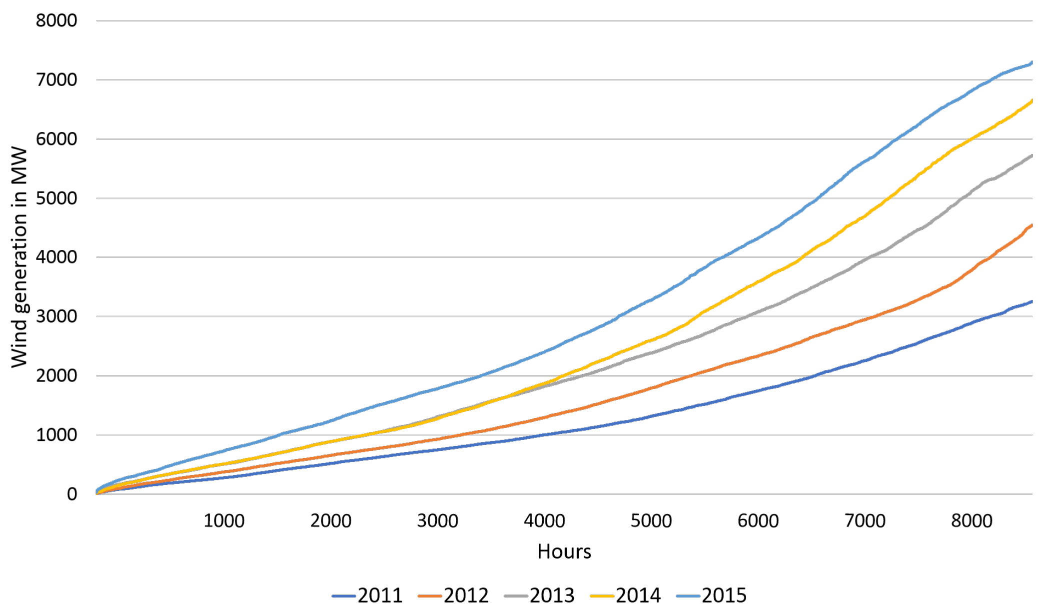


Figure 3.3: Total wind generation during each year from 2011 to 2015 (RenewableUK, 2017)

councils the ability to approve wind farms on sites that have been designated as part of a local or neighbourhood plan, and where the proposed project has the backing of a local community. According to the Energy and Climate Change Committee (ECCC) these policy changes mean that the UK is set to miss its key EU renewable energy target for 2020 (ECCC, 2016). This claim was backed by a number of members of parliament (Harvey, 2016).

Although the Government has agreed to press ahead with an intensification of offshore farms to demonstrate its commitment to the green agenda, a smaller focus on renewable energy has the potential of setting back the progress of onshore wind generation in Britain and can also possibly send a signal to investors regarding the high level of risk associated with investing in renewable generation in Great Britain. Changes in policy and local industry might disrupt the market and reveal themselves as a challenge for less mature renewable technologies, such as marine energy, and could result in discouragement for potential investors. Lastly, it could interfere with the goal of reducing polluting greenhouse gas emissions in the long term. In countries such as Spain, introducing policy to roll back feed-in tariffs that were supposed to continue for an extended period of time, resulted in a negative outcome (Mahalingam and Reiner, 2016). Other research shows (White *et al.*, 2013), that maintaining consistent energy policy and the manner in which policies are changed are key for achieving a greener energy system.

3.1.3 Solar power

Substantial solar power in Britain has been around for less than a decade, with first mainstream installations taking place in the 2000s. In recent years installed capacity has grown, mostly due to reductions in the cost of PV panels, and the introduction of a feed-in tariff subsidy in 2010. After FiT was introduced the British PV market grew quickly; what followed was an introduction of various industrial projects and thousands of domestic installations (KPMG LLP, 2015).

The growth of solar deployment by capacity for Great Britain and Northern Ireland is represented in Figure 3.4 and the UK solar deployment by accreditation is in Figure 3.5. The values represent growth up to the month of May 2017 (BEIS, 2017g).

It features the now no longer active, Renewable Obligation. There is potential to increase the British solar capacity, however, NGC expressed concern that the grid cannot take much more than 10 GW of solar capacity without making the operation of the transmission system more difficult without heavily relying on interconnectors (National Grid, 2012). Beyond this level, it could exacerbate problems with regulating downwards over the summer weekend minimum and could increase the volume of wind generation constrained off. According to the Solar Trade Association (STA), the construction of additional electricity storage would mitigate these problems (Aurora Energy Research, 2016a).

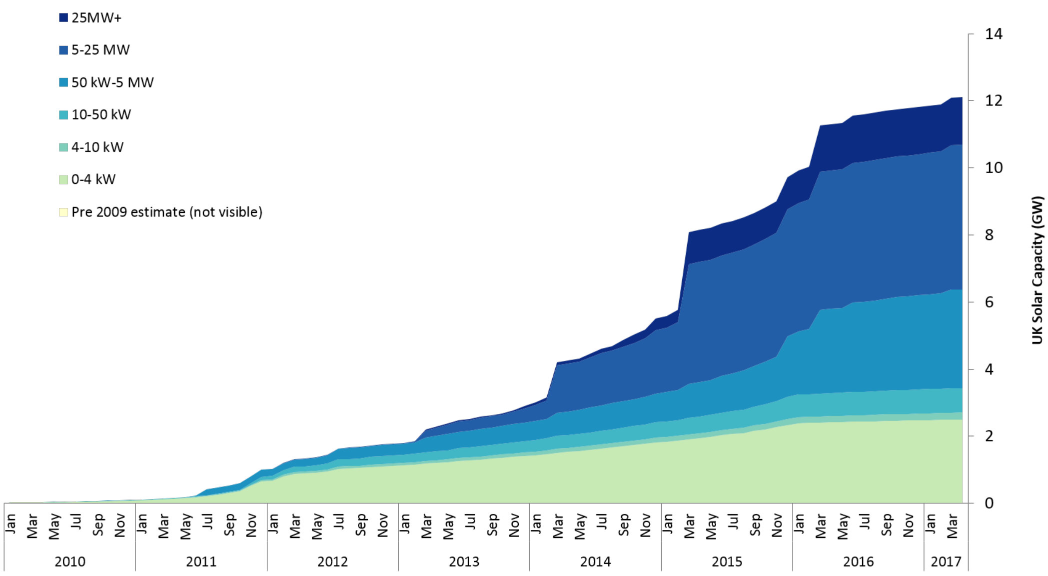


Figure 3.4: UK solar deployment by capacity until May 2017 from January 2010, in quarterly updates (BEIS, 2017g)

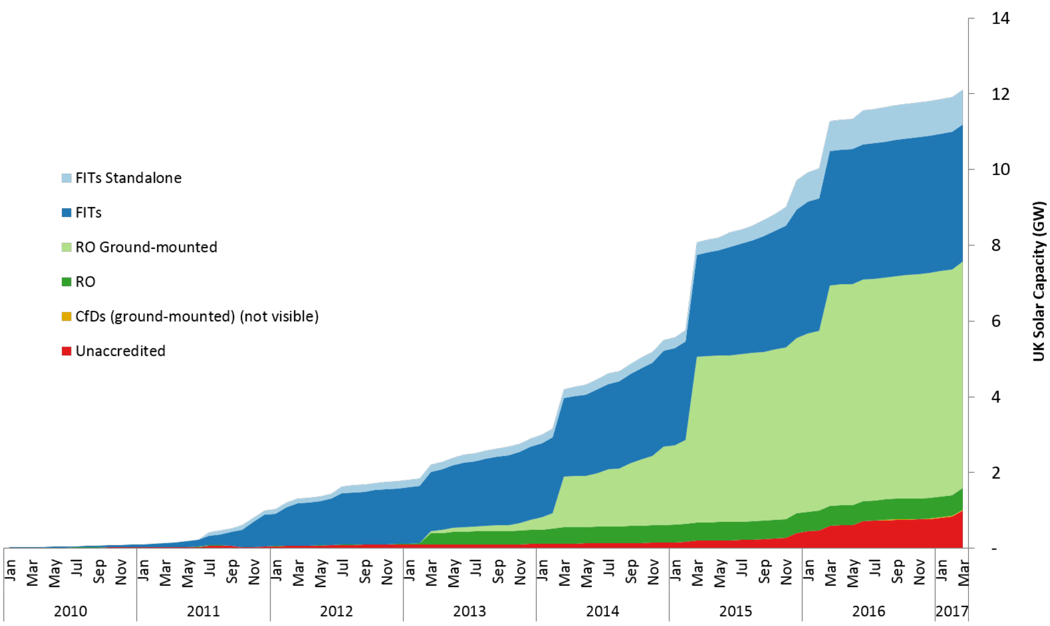


Figure 3.5: UK solar deployment by accreditation until May 2017 from January 2010, in quarterly updates (BEIS, 2017g)

However, despite concerns the transmission system as of now operates without any complications caused by additional solar capacity. As of the end of April 2017, overall UK solar PV capacity stood at 11,098 MW. Of that 11,903 MW of capacity was located within GB and 180 MW in NI (BEIS, 2017g). The government maintains that the UK will have 22 GW of installed solar capacity by 2020 (Department of Energy and Climate Change, 2014a). Further, in 2014 a study done by Imperial College London, claimed that by the end of the decade at least 10 million British homes would have solar panels installed, compared to half a million in 2013 (Nelson *et al.*, 2014). Not unlike wind power in GB, solar generation is currently undergoing a difficult period as all of the above predictions regarding the growth of solar deployment are from before 2016. This was before the previous government decided to cut financial aid under the FiT scheme intended solely for smaller scale generators, to households installing rooftop solar panels by 65% in November 2015. This directly followed the historic Paris climate deal, where they agreed to move swiftly to a low-carbon energy future.

The government's motivation for these cuts was to shield wider energy bills from the increasing impact of renewable energy subsidies, which should be sufficient to explain paying rooftop solar installers 4.39 pence per kilowatt hour instead of the previous 12.47 pence from February 2016 onwards. This is an improved figure after the Department of Energy and Climate Change's initial proposal of an 87% cut to 1.63 pence. Further, there would also be a £100 million cap on spending enforced by 2019 (Macalister, 2015).

The government also chose to cut the so called 'grandfathering' commitment, from the RO, which was intended to make sure any subsidy levels are protected for the entire lifetime of a project. Concerns were voiced by the STA, which described the removal of the grandfathering guarantee as nonsensical, since a £1 million investment of capital into a solar project in the present, in 20 years still means £1 million was invested as it is a sunk cost. Changing the level of support over the lifetime of a project is damaging for attracting investors, since it makes it less likely for them to be willing to take the risk and invest in the project (Bennett, 2015).

The negative aftermath of the cuts has already demonstrated itself as the amount of household solar power capacity installed between February and end of March of 2016 decreased by three quarters (Ofgem, 2016b).

The growth may slow down even more as the business rates tax increases to hit commercial solar power in April 2017, by up to eight times the current levels (Pratt, 2016). In the same data published by Ofgem it was also revealed only 21 MW of small-scale solar was installed in February and March of 2016, which is a much less compared to the same time period in 2015, when 81 MW of solar power was installed (Department of Energy and Climate Change, 2016). The cuts also led to several solar companies declaring bankruptcy.

A new low in solar deployment has been reached (BEIS, 2016b) as October 2016 was revealed as the slowest month yet under the new FiT, with just 2406 systems installed. The previous low recorded was in August 2016 with 2782 systems installed (Stoker, 2016).

As the costs continue to fall, the future of solar power in Britain remains uncertain due to increased investment risk given the changing policy measures. However, given that the costs are so low there is confidence solar power can still brand itself as an attractive investment in certain circumstances and that the market will recalibrate itself by presenting solar power as a package deal sold along with other smart technologies in a bid to increase solar electricity self-consumption.

3.1.4 Marine power

Tidal and wave technologies use the energy from the ocean to produce electricity. The marine industry in the UK is at an early stage, but is growing due to several innovative designs. Marine technologies are expected to make a significant contribution to renewable power generation after 2020 (EnergyUK, 2017).

The two most commonly discussed types of marine power are wave and tidal power, neither of which has been harvested commercially in Britain thus far (Ernst & Young, 2010).

Total theoretical UK resources are estimated to be follows (The Crown Estate, 2012):

- Wave: 69 TWh/year (27 GW);
- Tidal stream: 95 TWh/year (32 GW);
- Tidal range (barrage schemes): 96 TWh/year (45 GW); and
- Tidal range (lagoon schemes): 25 TWh/year (14 GW).

The distribution of marine resources broken down by type - wave, tidal stream, and tidal range - within British waters is visualised in Figure 3.6.

Wave power

An analysis of the cost of wave energy at different locations in the UK has shown that the least-cost areas for offshore devices are found to the west of Scotland and at the edge of British waters in the Southwest. If a sufficient number of farms of wave energy devices were built, then around 69 TWh/year could be extracted from the offshore sites identified (Carbon Trust and AMEC Environment & Infrastructure UK Limited, 2012). The wave sector provides the opportunity to scale up rapidly once the optimal technological solutions are confirmed. The technology has the potential to make large efficiency and energy capture improvements not available to other forms of low-carbon generation. In addition to the developments in Scotland, combining the investment into wave and tidal energy, along with publicly funded Welsh research projects, brings the total to £45.4 million spent in Wales on the development of marine energy (Marine Energy Pembrokeshire, 2015).

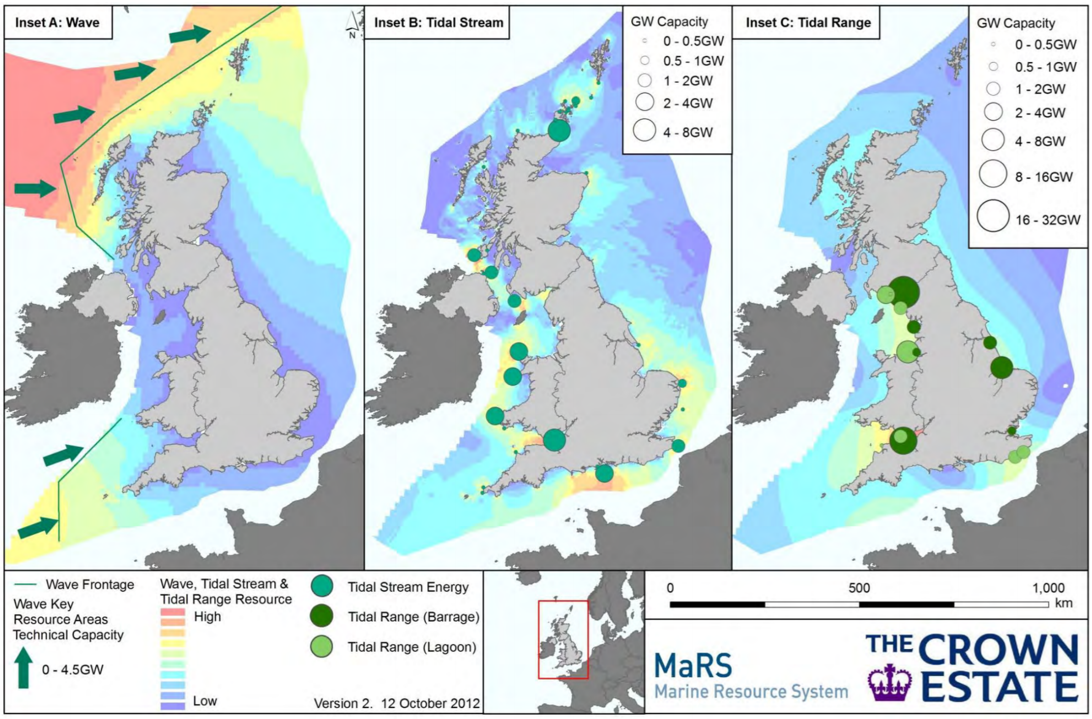


Figure 3.6: Distribution of wave, tidal stream, and tidal range energy resources (The Crown Estate, 2012)

Tidal power

There are similar amounts of tidal stream resources in English, Scottish, and Welsh waters, and also tidal stream resources off the coast of Northern Ireland. England and Wales share the largest single area of tidal range resources, in the Bristol Channel and Severn Estuary (The Crown Estate, 2012).

A recent government review backed the development of the Swansea Bay tidal lagoon and ministers have been urged to strike a subsidy deal for the lagoon's development (Department of Energy and Climate Change, 2015b).

3.1.5 Hydroelectric power

Hydroelectric power is a well-established technology in GB. The flow of water is used to turn turbines to generate electricity. There are different types of hydro power including those using the natural flow of the river or dam storage schemes (EnergyUK, 2017).

In 2016, the hydroelectric capacity in Britain was 1586 MW, which does not include pumped storage (National Grid, 2017a). Pumped storage capacity stood at 2744 MW in the same year. It is eligible for CfDs and competed in the first renewable auction, however, no projects secured funding. It was ineligible to run in the second renewable auction intended for less established technologies (Maroulis, 2017). Details of the auction prices are summarised in Table 3.1.

Table 3.1: Strike prices for hydroelectric power from the first renewable auction (Maroulis, 2017)

	CFD Strike Prices (GBP/MWh, 2012 prices)				
Technology	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**
Hydro (>5MW and <50MW)	100	100	100	100	100

In Britain, there are three types of hydroelectric schemes (BEIS, 2013b):

- Storage schemes;
- Run-of-river schemes;
- Pumped storage.

Scotland has in particular been very successful with harnessing hydropower's potential as they were quick to encourage the development of new projects. Water Environment (Controlled Activities) (Scotland) Regulations 2011 gave Scotland's hydropower development the push it needed (Scottish Environment Protection Agency, 2017).

Forestry Commission Scotland (FCS), whose estate covers nearly 10% of Scotland, is seeking developers to create new run-of-river hydroelectric schemes. FCS considers that there is at least 50 MW of potential at sites identified on their ground, much of this in the Highlands and Islands. The Scottish Government has permitted other hydro projects within the Highlands and Islands, including (HI-energy):

- A 3.54 MW run-of-river scheme near Evanton in Rossshire, established in 2014 and generating 10 GWh of energy per year, equal to the requirement of about 2,000 homes. It was the largest hydro facility to be developed by RWE Npower Renewables;
- On the Ardtornish Estate near Claggan in Argyll an existing river scheme was doubled in size to 1.5 MW capacity.

3.1.6 Biomass generation

Biomass production and consumption, especially when combined with CCS, offer a credible route for Britain to deliver negative emissions. Low-cost routes to 80% reductions in greenhouse gas emissions foresee around 130 TWh per year of energy being delivered from bioenergy sources. This equates to approximately 10% of total UK energy demand in 2050 (EnergyUK, 2017). In 2016, the biomass capacity in GB was 2533 MW. The biggest biomass project in Britain is the former coal-fired power station, Drax, which provides 6% of UK's electricity and 15% of its total renewable electricity . Previously only fuelled by coal, Drax is now a predominately biomass-fuelled generator and 70% of electricity produced is made from wood pellets rather than coal (Drax Group plc, 2017).

The company, Drax Group, received a financial subsidy from the UK government to convert a third unit into biomass, however, it is still looking for funding to convert the fourth unit as well as the government previously declared it was ineligible for subsidies (Vaughan, 2016).

Table 3.2: Strike prices for biomass power from the first renewable auction (Maroulis, 2017)

	CFD Strike Prices (GBP/MWh, 2012 prices)				
Technology	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**
Biomass Conversion	105	105	105	105	105
Dedicated Biomass with CHP	125	125	125	125	125

Biomass and biomass conversion competed in the first renewable auction and the strike prices are listed in Table 3.2 (Maroulis, 2017). However, only biomass with combined-heat-and-power was eligible for the second auction, and not biomass conversion (Voegele, 2016).

3.2 Energy storage

Electrical energy storage presents itself as the mediator between the intermittent nature of renewables and those periods of high needs for demand when said generation isn't available without having to rely on fossil-fired generation. It is considered one of the key elements in the process towards a flexibly operating British low-carbon economy. However, high costs and not always convincing conversion rates stand in its way from achieving the mediator role faster.

3.2.1 Introduction

There are four main storage categories: mechanical, thermal, electrochemical, and other types of chemical storage. Mechanical energy storage encompasses hydroelectricity, pumped hydropower energy storage (PHES), compressed air storage (CAES), flywheel energy storage, and gravitational potential energy storage with solid masses. Thermal energy storage allows for temporary storage or removal of heat. An example is latent heat thermal energy storage (LHTES). Under electrochemical storage falls rechargeable batteries, flow batteries, supercapacitors, and ultrabatteries.

In the last capacity auction in December of 2016, storage was awarded 3201 MW of capacity or 6.11%. Of that 500 MW went to new-build battery storage. Only 18.3 MW of storage capacity exited from the auction or 0.11% (National Grid, 2016a).

3.2.2 Storage use in Britain

According to the NG FES in the last analysis year, 2040, Britain should have 9.3 GW of storage in the Gone Green scenario and 14.9 GW in the Consumer Power scenario, which excludes PHES. Predictions for every scenario between the years 2016 and 2040, also by NG (National Grid, 2016b), are displayed in Figure 3.7.

On the transmission system level the EES types used are: battery, CAES, and PHES, with battery and PHES predicted to have the largest capacities deployed. On the distributed capacity

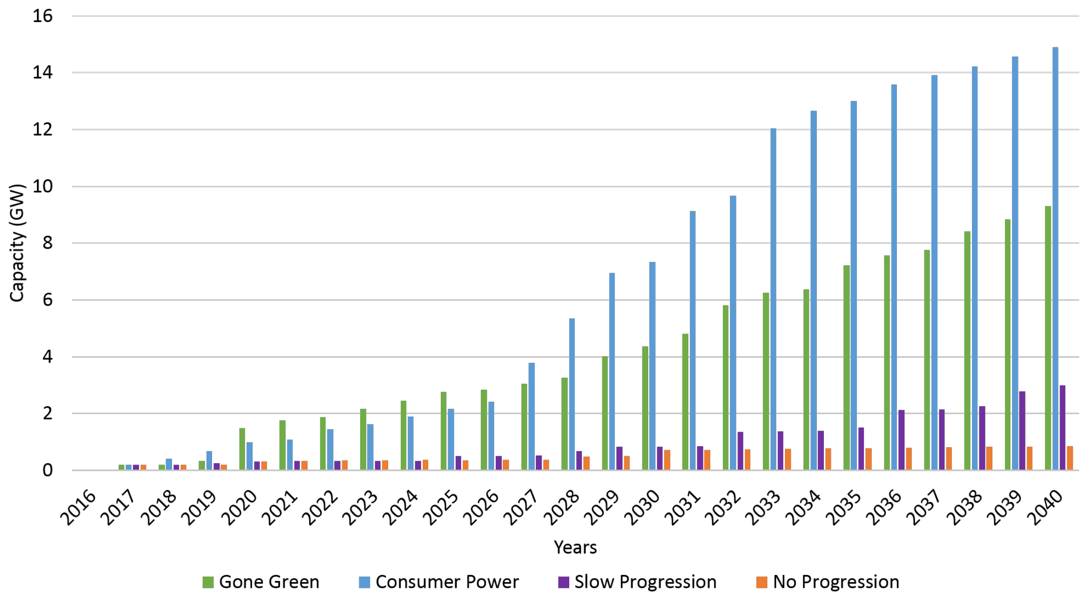


Figure 3.7: Installed storage capacities from 2016 to 2040, excluding pumped storage (National Grid, 2016b)

level there is liquid air energy storage (LAES), also known as cryogenic energy storage, battery, and battery associated with solar, which is predicted to witness the biggest capacity increase in all NG FES. LAES is still a technology in the demonstration phase rather than being commercial though it is expected to see rapid development in the next few years. The NG FES do not detail, which batteries it considers when listing 'battery associated with solar' but lithium-ion and lead-acid batteries are most commonly associated with solar PV storage (Bloomfield *et al.*, 2016).

Table 3.3 includes characteristics for each of the described EES types (The Grantham Institute and Imperial College London, 2015), (Sciacovelli *et al.*, 2016), (Roselund, 2017), and (Akinyele and Rayudu, 2014).

There are many different types of energy storage batteries, however, NG does not state what sort of battery storage they have in mind for GB but merely lists the umbrella term. Types of battery energy storage fall under two categories, solid state and flow batteries. Solid state batteries are: lead-acid (Pb-acid), nickel-cadmium battery, lithium-ion battery (Li-ion), and sodium sulfur batteries. Out of these Pb-acid and Li-ion are the most known ones. Some examples of flow batteries are: iron-chromium (ICB), vanadium redox (VRB), and zinc-bromine (ZNBR) batteries (Energy Storage Association, 2017a). Different types and classifications of energy storage technologies are broken down further in Figure 3.8.

For the model deployed here, the two types of storage technologies that were aggregated were PHES and Li-ion battery, as they are predicted to have the highest future capacities according to National Grid.

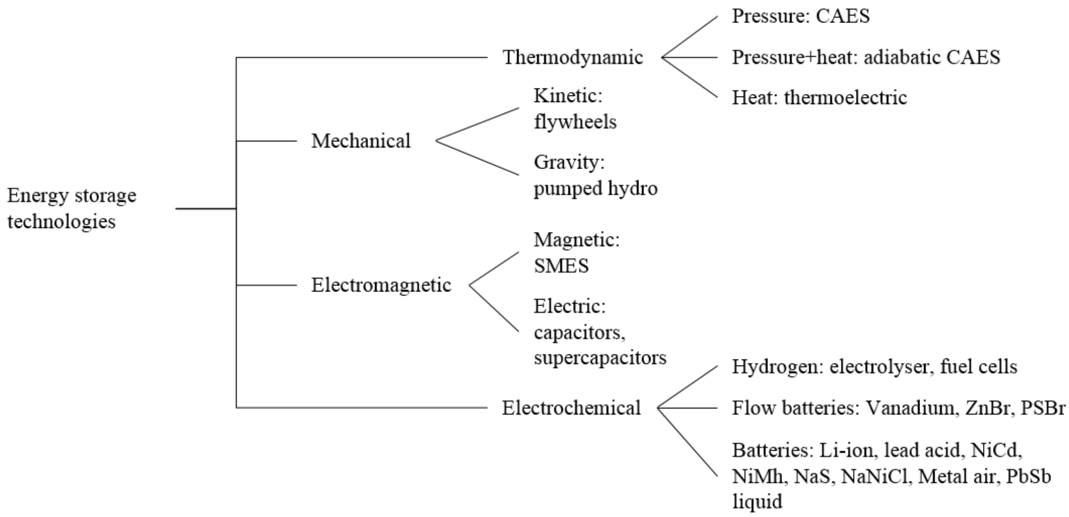


Figure 3.8: Classification of energy storage technologies

Table 3.3: Energy storage characteristics (The Grantham Institute and Imperial College London, 2015), (Sciacovelli *et al.*, 2016), (Roselund, 2017), and (Akinyele and Rayudu, 2014)

Storage type	**Capacity (GWh)**	**Efficiency (%)**	**Daily self discharge (%)**	**Capital cost ($/kWh for 1 - 8hr energy system**	**Response time**
PHES	0.5 - 20	70-85	>0.5	10 - 1000	Seconds - minutes
CAES	0.5 - 2.5	50-75	>10	10 - 1000	Minutes
LAES	Currently 0.015, anticipated up to 0.2	Anticipated up to 60	0.5-1	Due to the technology's infancy, capital cost is not yet available	$\geq$ 5 min
Li-ion batteries	0.03	80-90	$\sim$0	100 - 1000	Milliseconds
Pb-acid batteries	0.04	65-85	$\sim$0.2	10 - 1000	Milliseconds
Redox flow batteries	0.003 - 0.12	65-85	$\sim$0	100 - 1000	Milliseconds

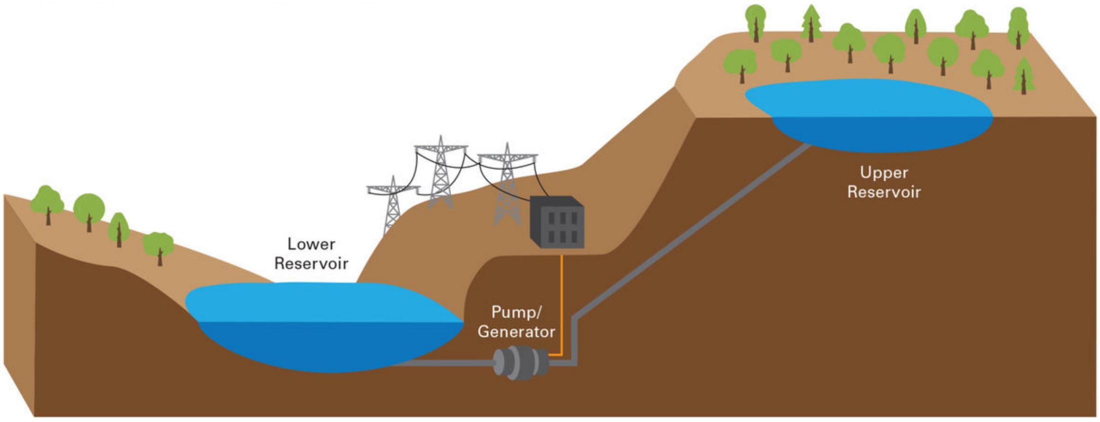


Figure 3.9: Operating process of a PHES broken down (Dominion Energy, 2017)

3.2.3 Pumped hydroelectric energy storage

Currently pumped hydroelectric energy storage is the most common type of energy storage around the world and represents 99% of the worldwide bulk storage capacity (Sciacovelli *et al.*, 2016).

Pumped hydroelectric energy storage stations have reversible pump-turbine/motor-generator assemblies installed, which function as both pumps and turbines. What separates pumped storage stations from traditional hydroelectric stations in that they are a net consumer of electricity, due to hydraulic and electrical losses incurred in the cycle of pumping from lower to upper reservoirs. However, these plants are typically highly efficient (round-trip efficiencies reaching greater than 80%) and can prove very beneficial in terms of balancing load within the overall power system. Pumped-storage facilities can be cost effective due to peak/off-peak price differentials and their ability to provide ancillary grid services (Energy Storage Association, 2017b).

Figure 3.9 visualises how pumped hydroelectric energy storage operates (Dominion Energy, 2017).

Although National Grid's FES appear to depend highly on PHES, the scope for more PHES in Great Britain depends on the environmental conditions and local opposition. Creating the perfect conditions for PHES means interfering with the local landscape as typically an artificial lake has to be created on top of a hill for the technology to function. The other major obstacle highly related to the first one is the local opposition resulting from such actions as was observed in Norway (Gullberg, 2013).

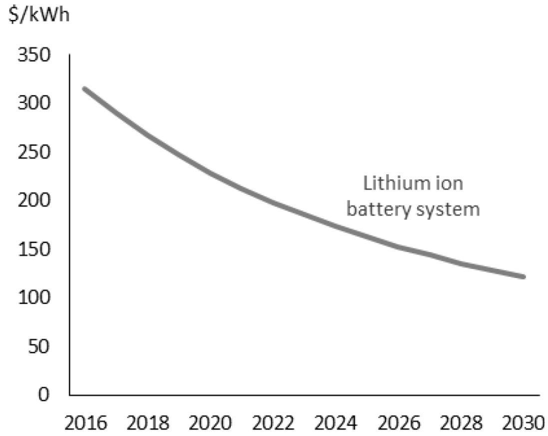


Figure 3.10: Forecast for production cost for a Li-ion battery storage system in the United States from 2016 to 2030 (Statnett, 2016) and (Curry, 2017)

3.2.4 Lithium ion battery storage

Lithium ion batteries were initially used solely for consumer products, however, as companies began to develop larger format cells for energy storage applications, they have emerged as a useful complement to electric vehicles being able to power them. The flexibility of Li-ion technology in EV applications, from small high-power batteries for power buffering in hybrids, to medium-power batteries providing both electric-only range and power buffering in plug-in hybrids, to high-energy batteries in electric-only vehicles, has similar value in energy storage. Li-ion batteries have been deployed in a wide range of energy storage applications, ranging from energy-type batteries of a few kilowatt-hours in residential systems with rooftop photovoltaic arrays to multi-megawatt containerised batteries for the provision of grid ancillary services. It is likely that due to this versatility of use it is predicted that Li-ion batteries will have one of the largest capacity growths in GB (Energy Storage Association, 2017c).

In the future, the production cost of Li-ion battery system is supposed to drop significantly, as suggested in Figure 3.10.

3.3 Demand side management

Not just in Britain, but throughout all of Europe there is an increased concern regarding energy system adequacy and preparedness; that is - will the system be able to cope with peaks of high demand? Demand increases are expected due to population growth and increased electrification of sectors such as heat and transport. A shift from fossil fuels to electricity, combined with greater uptake of renewables, has been identified as a means of improving diversity of energy supply and meeting greenhouse gas emission reduction targets (Element Energy, 2012).

The current power system in GB was built after the First World War, when the National Grid was established with the intention of connecting power stations with centres of demand. During that time, there were few places of generation so it was not difficult to adapt to customers' needs when putting the very first pylons on the horizon. When designed, the grid that ended up growing across the island, was well equipped to respond to the manageable advances in technology without any risk of grid performance complications. However, as time went by the additions to the grid grew more and more elaborate and nowadays it seems the grid is no longer suited to keep up with what current power systems technology demands from it. There has been a significant push for the development of the smart grid. Among the novelties, the smart grid brings is demand side management, also known as demand side response (DSR). This section aims to present the different types of demand side management and their role on improving the flexibility of demand side. Global, European, and domestic policies, initiatives, and directives are studied, and the history of demand side management is analysed. The benefits and costs of demand side management programmes are assessed.

3.3.1 Demand side market participation

In recent years, improving energy security and affordability at the same time as trying to combat polluting carbon emissions, has finally been finally recognised as a part of a broader policy agenda impacting every sector rather than just energy. Previously the answer to these efforts has been presented only from the supply side. Nowadays, due to high investment costs of some low-carbon power options and the less than ideal characteristics of others, such as intermittency of renewables, energy utility companies are turning to the demand side to help them tackle these issues to meet the growing pressures from governments, stakeholders, and the public. Alternative solutions include energy storage, cross-border interconnections, and DSM (Warren, 2014).

There are many benefits to involving the demand side in the electricity market as it makes the markets more efficient and competitive. Furthermore, there is already a relatively low utilisation of generation and networks (of about 50%) meaning there is a significant scope for DSM to contribute to increasing the efficiency of the system investment (Syrri and Mancarella, 2014), (Strbac, 2008). In addition to allowing to utilise the existing system in a more efficient way and gain more from what it is already designed to offer, it would also aid with the integration of other smart grid technologies such as intermittent renewable generation.

In recent years, electric utilities and power network companies underwent the restructuring of their operations from vertically integrated mechanisms to open market system. Following the policies that restructured and deregulated the electricity supply industry the way, the system began to be operated also underwent significant changes. In the past, the traditional way of tackling demand was to supply all power demand, whenever that took place. The new approach proposes a more minimalistic manner of dealing with demand needs and fluctuations, claiming that the system as a whole will be at its most efficient if fluctuations in demand are kept as small as possible.

For an electricity system to operate reliably, there is a need for a perfect balance between the supply and demand side in real time. Achieving and more importantly maintaining such a balance is not an easy feat since both supply and demand levels are susceptible to rapid changes for many unforeseen reasons like generation unit forced outages, outages occurring on transmission and distribution lines, and sudden changes in load. The infrastructure of the entire electricity system requires investments of large sums of money and this modern, flexible approach advocates that a cheaper way of operating the system is by employing the many services of demand side management. Demand response, which encourages end users to change how their electricity is used (Kim and Shcherbakova, 2011) and is the type of DSM primarily evaluated in this chapter, has the potential of reducing peak demand and easing impending peak generation capacity shortages that are expected to manifest themselves as an outcome of plant closures over the coming decade in Britain (Ofgem, 2012). DR could aid in reducing potential increases in peak demand from electrified heat and transport in the medium to long term (Strbac *et al.*, 2010).

However, it could be that simply poor DR regulation is what is preventing DR from witnessing a more widespread provision across Europe (Smart Energy Demand Coalition, 2011). Even in the times of the impending smart grid, in a system, where electricity generation is by far the biggest agent, the role of DR stays minor. This is true for the UK as well. Out of all European countries, DR provision is most prominent in the UK (Grünewald and Torriti, 2013), yet it was estimated that in 2012 around 84 MW of responses came from aggregated load reduction, which made up 3% out of the aggregated Short-Term Operating Reserve (STOR) services, which totalled 14% or 409 MW in 2013 (Macleod, 2013), with the non-aggregated STOR services making up the other 86%. This number rose to 6% (195 MW) out of the aggregated total of 21% (705 MW) in 2015 (National Grid, 2015). Aggregators are a key aspect of the STOR market, which provides additional active power from generation or demand reduction.

3.3.2 Development of demand side management

From a global perspective, DSM programmes can be traced back to the 1970s. The initial DSM programmes were constrained by the technology that was around - measuring and verifying was time consuming in addition to high costs that arose, leading to programmes being focused only on the largest customers. The next generation of DSM programmes promises to change the face of energy savings throughout the global economy (Davito *et al.*, 2010).

Types of demand side management

The types of DSM vary between different literature sources. However, there seem to be three that appear consistently, which are: energy efficiency, dynamic demand, and demand response.

On-site backup, which usually refers to generation and storage, also appears in some literature (Warren, 2014) as a DSM type, however, it is more commonly classified under the DR subcategory (Albadi and El-Saadany, 2008). In the UK, on-site backup generation and storage have historically been used for smoothing the load curve to reduce peaks, such as through diesel generators in industry and hot water storage tanks in houses. In the UK, on-site backup plays an important role as a balancing mechanism (Warren, 2014).

The three main types of demand side management are presented below:

- **Energy efficiency**
  Energy efficiency directives are geared towards achieving an increase in energy efficiency. Energy efficiency directives offer the customers to save money in exchange for giving up some of their normal energy use. A consumer participating in an energy efficiency programme receives the same standard of the end service or product but for less energy consumed (Davito *et al.*, 2010). The method aims for a permanent reduction of demand by using more effective load-intensive appliances. The most common example of successful implementation of energy efficiency is the switch made from using traditional incandescent light bulbs to using light-emitting diode (LED) lights, fluorescent lights, or maximising the use of natural light. Energy efficiency tends to increase with advances in certain technologies or finding an improved way to carry through a production process, allowing for the same tasks to be performed by using less power (International Energy Agency, 2006). Another example of this is switching from a regular refrigerator to a more efficient model. The service itself remains the same, however, the new machine uses much less energy. Allowing real-time access to information through smart services presents more clarity for customers for immediate energy consumption (Davito *et al.*, 2010). Energy efficiency can be achieved in simpler ways such as choosing to wear another layer of clothing, instead of increasing heating in the house, and thus avoiding paying higher electricity bills. Reducing energy use is also seen as a solution to the problem of reducing greenhouse gas emissions. According to the International Energy Agency (IEA), improved energy efficiency in buildings, industrial processes, and transportation could reduce the world's energy needs in 2050 by one third, and help control global emissions of greenhouse gases (International Energy Agency, 2006).
- **Dynamic demand**
  Dynamic demand is used to speed up or delay operating cycles of appliances by a few seconds to increase the diversity factor of the set of loads. The original idea was pitched in the 1980s by Fred Schweppe (Schweppe *et al.*, 1988). By monitoring the power factor

of the power grid, and their own control parameters, individual, intermittent loads would switch on or off at optimal moments to balance the overall system load with generation, reducing critical power mismatches. As this switching would only advance or delay the appliance operating cycle by a few seconds, it would be unnoticeable to the end user and is the foundation of dynamic demand control. There are similarities between dynamic demand and demand response when managing electricity consumption based on supply conditions for domestic and industrial users. In the case of the former, electricity use is reduced to mitigate the problems occurring with the grid and in an effort to avoid paying higher electricity prices in the latter case.

- **Demand response**

  The idea behind demand response is fostering the change in electricity usage by end-use customers that deviates from how they would normally use electricity based on how much the electricity price changes over time. Additionally, DR can represent the incentive payments introduced to encourage lower electricity use during times at which wholesale market prices are high or when the system is not entirely reliable or in danger. Demand response is also used to shape customer load during peak hours when the generation capacity is in danger of being exceeded (Department for Business, 2007). Demand response also encompasses every pre-planned and conscious modification to how electricity is normally consumed by end-use consumers that aim to change the timing, level of instantaneous demand, or overall consumption of electricity (Albadi and El-Saadany, 2008). Initially, the focus of DR was to reduce peaks to put off the high costs associated with building new generation capacity. Nowadays, however, DR is also used to help with smoother integration of intermittent renewable energy, as it aids with changing the net load shape (Frincu *et al.*, 2015).

  Demand response relies on user engagement and end users' willingness to change their habits for energy use during times of peak periods or high prices in the electricity system. This means users would have to actively change their established patterns to adapt to the electricity markets and systems, and thus doubt has been expressed about the implementation of DR in smaller households. The impact on the customers' comfort means that this technique is better suited for industrial and commercial settings than for residential homes (Department for Business, 2007). However, it only remains a lucrative decision for the owner of the business as long as the financial compensation for shifting the time of the industrial process is larger than the costs arising from halting and rescheduling the industrial cycle (Vieira *et al.*, 2003).

  Issues have been raised around consumer privacy (due to the two-way flow of information, which could be considered intrusive); customer satisfaction and more importantly their inclinations to even participate in such projects; and lastly, accuracy due to the small scale of each individual participating project. Besides the obvious potential reduction in electricity bills and incentive payments, which might not mean a lot to higher income households, the real benefit of DR lies in its contribution to the electricity system as a whole and the potential it has to quickly mitigate complications arising in the grid. Wider implementation of DR could result in benefits related to the market such as a decrease in prices due to a better use of available infrastructure, which could lead to avoided infrastructure costs (Albadi and El-Saadany, 2007). Moreover, DR programmes can increase short-term capacity using market-based programmes, which could in turn result in deferred capacity costs. The entire system and its participants would likely experience a massive surge in reliability (Shivakumar *et al.*, 2014) as there would be a reduction in power outages to which the consumers themselves would contribute even if unknowingly. The diversification of resources would give the operator more options leading to a decrease in forced outages.

Customer response

Demand response heavily relies on customer participation and response. Customer response can be accomplished by implementing one or all three general objectives. Each such objective is based on cost and various actions taken by the customer (United States Department of Energy, 2006). The first objective is geared towards convincing customers to moderate and decrease how much electricity they use during peak periods of high electricity prices while maintaining their regular patterns of consumption during other noncritical periods. However, following this action includes a momentary reduction of comfort as the consumers do not get to exercise the full extent of ease regular electricity use offers during noncritical periods. Additionally, various TV programmes can be recorded and watched afterwards and not during the time of televised live performances or original broadcast.

Another customer method for responding to high electricity prices is by shifting some activities that rely on high energy use from peak to off-peak intervals. This can be achieved by not doing regular household activities such as the employment of dishwashers during usual hours when the majority of the general public would also choose to do so but instead making use of them during less conventional time periods in order to relieve the intensity of such demand operations during peak times (Valero *et al.*, 2007). This is a rather ideal method for residential customers as it does not incur any extra cost and there are no losses involved in the procedure. The high automation of modern household machines allows for the times of use to be pre-set thus causing no additional inconvenience to the consumers choosing to employ such peak reducing platforms. It does, however, cause an inconvenience for larger, industrial customers if they choose to assign another time for some activities and thus rescheduling costs to make up for lost services are incurred (Sezgen *et al.*, 2005), (Vieira *et al.*, 2003).

The third and final method of customer response utilises the service of on-site generation. On-site generation is distributed generation owned by the customers themselves and thus provides an additional degree of reliability and independence. Customers, who are also providers of their own power have the benefit of enjoying electricity generation with little to absolutely no change to the structure of their electricity use. Choosing to follow this type of customer response does cause demand to appear smaller and from a utility's point of view the patterns in electricity use will undergo considerable modifications (Albadi and El-Saadany, 2008).

3.3.3 Demand response programmes

There are multiple types of DR programmes that have been and are still continuously being developed by different utility companies around the world. This thesis chooses to focus on those brought forth by the United States Department of Energy (US DOE) as they are the most universally accepted and discussed methods of altering the demand side's use of electricity (United States Department of Energy, 2006).

Demand response initiatives fall into two groups: Incentive-Based Programmes (IBP) and Price-Based Programmes (PBP). IB programmes are broken down to a greater extent into classical programmes and market-based programmes (Khajavi *et al.*, 2011). Under Classical IB programmes fall Direct Load Control programmes and Interruptible/Curtailable Load programmes. Market-based IBP contain Emergency DR, Demand Bidding, Capacity Market, and the Ancillary Services Market.

Classical IB programmes award their participants with incentive payments for their participation, but market-based IB programmes award their participants with payments reflective of their performance (Albadi and El-Saadany, 2008). Further, classical IBP offers customers that choose to partake in the directive to receive participation payments, in a form of bill credit or discount rates, for their involvement in the directive. However, market-based programmes offer monetary reward to participating customers, proportional to the extent to which they are willing to reduce their loads during high demand times (Aalami *et al.*, 2010).

The various IB programmes are further explained in Table 3.4. The payments, incentives, and market types for participation are matched with their respective programmes. Then, the time between the payment and the time of load curtailment is defined. Some programmes are on stand-by, for others the time of action is pre-determined, and some are intended for immediate action. The conditions for which these programmes are needed and the result of programme participation are also described.

Table 3.4: Incentive based programmes (United States Department of Energy, 2006), (Van Isterdael, 2013), (Albadi and El-Saadany, 2008), (Saebi *et al.*, 2010), (Eid *et al.*, 2016), (Perumalla, 2015)

	Payment	**Response time**	**Conditions**
Classical			
Direct Control	Upfront incentive payment, rate discounts	Short notice	Remote automation turn off
Curtailable	Upfront incentive payment, rate discounts	Pre-determined	Participants reduce load to predefined value
Market-based			
Demand Bidding	Wholesale market	Day-ahead, day of	High electricity prices
Emergency	Upfront incentive payment	Immediate	Emergency
Capacity	Capacity market	Day-ahead	System contingency
Ancillary Services	Spot market	Stand-by	Grid reliability maintenance

Price-based programmes rely on dynamic pricing rates, which depend on the real-time cost of electricity, which causes them to fluctuate. Different types of dynamic pricing rates are listed below (Williamson, 2014), (Albadi and El-Saadany, 2008), (Kii *et al.*, 2014), (United States Department of Energy, 2006), (Yang *et al.*, 2014) (Bloustein, 2005), (SDG&E, 2012), (Eid *et al.*, 2016), (Aswin Raj C. *et al.*, 2015):

- **Time of Use (TOU)** - rates of electricity price per unit consumption that differ in various time periods. TOU rates have two time intervals - peak and off-peak.
- **Critical Peak Pricing (CPP)** - intended to dramatically reduce load during the relatively few, very expensive hours and come on top of TOU rates.
- **Extreme Day Pricing (EDP)** - valid throughout the entire day on which extremely high electricity prices occur.
- **Extreme Day CPP (ED-CPP)** - employs CPP rates for peak and off-peak periods on extreme days; flat rates are used normally.
- **Real Time Pricing (RTP)** - based on either the actual market value or the utility's cost for energy at the time when it is used. Utilities typically pay varying amounts for energy depending on the time of use and the quantity needed at that time.

3.3.4 Demand response benefits and costs

Demand response costs

There are various types of costs that come with all demand response programmes. Figure 3.11 offers a breakdown of these costs, where both, DR programme owners and participants, incur initial and running costs (United States Department of Energy, 2006).

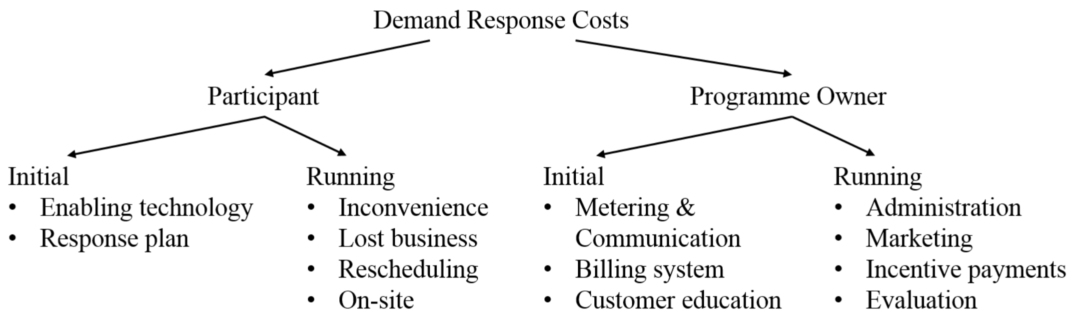


Figure 3.11: Costs of DR programmes for each participant based on (United States Department of Energy, 2006) directives and (Albadi and El-Saadany, 2007)

A participant at the beginning of the programme has to invest their own money for the installation of devices, such as energy management systems and smart thermostats, allowing them to participate (Eid *et al.*, 2016). Besides the initial investment cost, the running costs can only be approximated due to variation in programmes and devices themselves. The loss of comfort when having to change the preferred settings to participate in the programme is another unquantifiable cost. In the case of on-site generation one must also account for fuel and maintenance and operating costs (Albadi and El-Saadany, 2007).

Significant costs can occur for commercial programme participants since in order to avoid being penalised, during times of high demand they must halt any ongoing industrial processes (Kreuder *et al.*, 2013), which must then be rescheduled, with the outcome being a potential loss of revenue (Kopanos *et al.*, 2008).

For the programme owner, the initial costs come from developing the programme and any potential devices associated with running it. The running costs arise from having to make incentive payments continuously in order to keep the participants motivated. However, in addition to that, to attract new customers and to retain the existing ones, the owner has to invest in the promotion of the programme, as the impact demand response has on lowering demand is very sensitive to the number of participants (Strbac, 2008). Improvements to the technology associated with the programme must also be made (Pinney *et al.*, 2016).

Demand response benefits

The main benefit resulting from demand response programme participation is a reduction in the costs of electricity bills proportional to reductions in electricity use during peak-time periods (Jazayeri *et al.*, 2005).

An encouraging aspect for involvement in DR programmes for those choosing to partake in them is that savings can occur even if regular demand for electricity is maintained during periods of critical use. That is the case, of course, if regular electricity demand of a consumer is smaller than that of their class average (The World Bank, 2005). Furthermore, overall energy

Demand Response Benefits

Participant
- Incentive payments
- Bill savings

Market-Wide
- Price reduction
- Capacity increase
- Avoided/deferred infrastructure costs

Reliability
- Reduced outages
- Customer participation
- Diversified resources

Market performance
- Reduces market power
- Options to customers
- Reduces price volatility

Figure 3.12: Benefits of DR programmes for each participant based on (United States Department of Energy, 2006) and (Albadi and El-Saadany, 2007)

consumption could even be increased without extra cost incurring if more off-peak equipment is used. Benefits from demand response programme participation for various actors are demonstrated in Figure 3.12.

The primary intended benefit of DR is a reduced wholesale electricity price due to energy equipment and infrastructure being used more efficiently, leading to less frequent periods of very high demand, which require the use of expensive peaker plants (Albadi and El-Saadany, 2007). Demand response programmes are able to mitigate transmission congestion, delay transmission expansion projects, and improve the reliability of the transmission grid. At the distribution level, DR can relieve voltage problems and reduce congestion at distribution substations (Eldali *et al.*, 2016).

Reliability benefits have the widest importance for all market actors. A thoroughly developed DR programme allows market actors to aid in decreasing outage occurrence (Pinney *et al.*, 2016). Consequentially, by doing so the actors reduce their own risk of having to experience an unplanned blackout or brownout (Strbac, 2008).

Additionally, DR programmes contribute to a better market operation and performance by offering more options to the market agents even in the case of no retail availability (Spees and Lave, 2007). The level of active control consumers have on markets as a result of market-based programmes and dynamic pricing programmes is a direct benefit. It helps improve the spot market by decreasing volatility (Braithwait and Eakin, 2002). Even a minimal reduction in demand leads to a considerable decrease in generation cost, which successively leads to an electricity price decrease (Caves *et al.*, 2000), as demonstrated in Figure 3.13. $d_{beforeDSM}$ is the (higher) demand before the impact of DR is taken into account, resulting in $d_{afterDSM}$. $p_{afterDSM}$ is thus a direct result of the demand decrease. This happens because generation cost increases exponentially when reaching near maximum generation capacity (Albadi and El-Saadany, 2007).

Finally, DR programmes have significant environmental benefits (Tsagarakis *et al.*, 2016), which manifest themselves in improved land use due to a smaller demand for building thermal

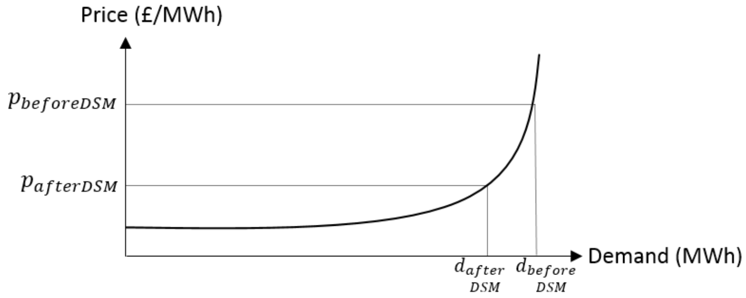


Figure 3.13: Simplified effect of DSM on wholesale electricity market prices, adapted from (Albadi and El-Saadany, 2008)

$p_{beforeDSM}$ and $p_{afterDSM}$ denote the price before and after DSM, respectively, and $d_{beforeDSM}$ and $d_{afterDSM}$ denote demand before and after DSM, respectively.

power plants, renewable generation, and transmission and distribution lines. A more systematic utilisation of resources has been linked to better air and water quality and an overall decrease in natural resource contamination and use (Gellings and Chamberlin, 1993), (United States Department of Energy, 2006).

3.3.5 Demand response costs and benefits in the UK

As literature shows (Bradley *et al.*, 2012) there is a reasonable case to assume DR in the UK could result in significant benefits for the UK, if not for all individuals. This could lead to lower than necessary consumer participation. However, making sure participants are incentivised to participate in DR is essential. Due to potentially substantial inconvenience costs, in addition to low monetary returns from reduced electricity use, the potential for high initial incentive and uptake is low. Sharing the supply side benefits along the wider supply chain can be achieved through an increased financial reward for participation, like reduced billing costs (Bradley *et al.*, 2012). Work done by DECC and Ofgem (Department of Energy and Climate Change and Ofgem, 2012) has demonstrated that only a modest increase in electricity savings can result in a substantial effect on electricity savings benefits. In their work, it was demonstrated that electricity savings generate the most significant DR related financial benefits, estimated to occur from a conservative assumption of a 2.8% reduction in the UK electricity use. DECC and Ofgem perform some sensitivities around this assumption, using alternative assumptions of 4% and 1.5% savings. When the 4% assumption is applied the value of electricity saved goes up from a value of £157 million for the domestic sector to £237 million. When the 1.5% assumption is applied the value reduces to £77 million (Bradley *et al.*, 2012). To access these benefits, participants' costs must be lowered to encourage consumer participation in the supply chain, so that as mentioned before, benefits are distributed fairly and not retained just for supply side purposes. In the future, technologies such as smart appliances and electric vehicles that go beyond smart metering could play a role in reducing costs for participants, maximising benefits, and therefore helping to enable the required level of consumer participation.

Smart metering is a necessary condition for several types of DR and an important cost. For the DR benefits to be maximised, the implementation of smart meters, must be done in a manner that ensures trust, customer acceptability, and a level of appliance education, or participation will decrease and the investments may not be used, which would lead to reduced DR benefits and increased costs. The actual costs of the infrastructure are also affected by customer engagement and trust, since if consumers are not properly informed on the benefits of smart meters and if they do not trust the installations, it could result in higher role-out cost due to decreased consumer willingness to participate.

It is essential the regulators are vocal about the certainty of the benefits from DR being spilled over from the suppliers, be it through various tariff structures or incentives. Thus, regulatory frameworks like EMR, must ensure that either direct or indirect barriers to consumer participation with DR are removed and that the system actively encourages DR so that benefits from DR are maximised. By doing so, electricity consumers and others see a fair return on the smart metering and other DR related investments through benefits directly gained from their DR. This is very important since suppliers will see the large benefits resulting from the smart metering investment, which generally will not require DR. However, consumers have to see and profit from these benefits in order to encourage their continued participation and decrease electricity consumption (and electricity shifting) that can reduce electricity bills and CO_2, and help ensure energy security and wider economic benefits to the UK demonstrated.

Ensuring these wider society benefits is particularly important considering that costs, e.g. smart metering infrastructure, are ultimately likely to be passed on to household and business customers from suppliers (Bradley *et al.*, 2012).

3.3.6 Development of DSM policy in the UK

The UK has been a global leader on DSM policy, especially energy efficiency policy, over the last 40 years (Mallaburn and Eyre, 2014). In 2012, the UK was ranked first overall out of 12 leading economies in the American Council for an Energy Efficient Economy's (ACEEE) international energy efficiency scorecard. However, this leading position was lost to Germany in 2014, which maintained the top position in the most recent report from 2016 (ACEEE, 2016b). The UK lost this position due to a variety of rollbacks (ACEEE, 2016a) :

- A 33% cut to the country's Energy Efficiency Obligations target in 2014
- A 20% cut to future Energy Efficiency Obligations spending in 2015
- Cancellation of the Green Deal in 2015

A high number of overlapping schemes led to their implementation being poorly executed and to low levels of acceptance. In addition to an internal energy and DSM scheme and policy overlap, concerns have also been raised over a potential overlap with climate change policies.

Further, a shift from regulatory and financial DSM policies to market-based (capacity market participation) and voluntary (industrial information hub) policies has been noted. This goes

Table 3.5: Current and previous (italics) UK DSM policies (Warren, 2014), (Rosenow, 2012), (Ofgem, 2017c)

Regulatory	Market-based	Financial	Voluntary	EU-wide
EESOP 1-3	Energy Efficiency Market Transformation	Feed-in tariffs	*Green Deal*	Energy Efficiency Directive
EEC 1-2	Economy 7	Renewable Heat Incentives	Information campaigns	Smart Meter Rollout Directive
CERT/ CESP	Economy 10	Enhanced Capital Allowances		Energy Labelling Framework Directive
ECO 1, *ECO 2*, ECO2t		Micro-generation Subsidies		Ecodesign Framework Directive

against what global experience has shown as without proper regulatory and financial support in place, DSM policies are often less effective. To ensure DSM will play an important part in future British energy policy, clarity, transparency, and stability are essential determinants of success (Warren, 2014).

Since the mid-1990s the UK has tested various types of policies of which the utility obligations have demonstrated the most success. EU-wide policies also helped foster domestic DSM policy in the UK as they helped to improve the monitoring and visualisation of energy consumption, and increase the energy efficiency of appliances, equipment, and buildings (Warren, 2014).

Table 3.5 contains current and previous DSM policies implemented in the United Kingdom. The programmes in italics are no longer active.

3.3.7 EU-wide DSM initiatives

In addition to the work done domestically, the UK also has to participate in different European DSM initiatives, which are presented below:

1. Energy Efficiency Directive
   Under the Energy Efficiency Directive, EU countries must set up an energy efficiency obligation scheme. This scheme requires energy companies to achieve yearly energy savings of 1.5% of annual sales to final consumers. In this context, the EED promotes energy efficiency obligation schemes or alternative measures to reduce energy consumption by final consumers (European Commission, 2017c).
2. Smart Meter Rollout Directive
   It is the EU's target for at least 80% of electricity meters to be replaced with smart meters by 2020 as long as it is cost effective. This smart metering and smart grids rollout can reduce emissions in the EU by up to 9% and lead to annual household energy consumption

decreases by similar amounts (European Commission, 2017b). On 30 November 2016, the Commission published a proposal (European Commission, 2017a) stating that all consumers should be entitled to request a smart meter from their supplier. Smart meters should make it easier for the consumers to profit from the digitalisation of the energy market and to access dynamic electricity price contracts.

3. Energy Labelling Framework Directive (ELF)
   Under the ELF directive manufacturers are obliged to label certain types of appliances to make it possible for consumers to have a comparison scale available of products based on energy efficiency and some other parameters (such as water consumption and noise level). It is also intended as an incentivisation tool to encourage the industry to develop more energy efficient appliances. The energy label rating calculation is based on energy efficiency and parameters related to the functionality of the product (such as performance/capacity), which establishes a balanced way to rank appliances (The European Parliament and the Council of the European Union, 2010).
4. Ecodesign Framework Directive
   The Ecodesign Directive was designed to provide consistent EU-wide rules for improving the environmental performance of products, such as household appliances, information and communication technologies or engineering. Under this Directive minimum mandatory requirements are enforced for the product energy efficiency. This decreases trade barriers and improves product quality and environmental protection (European Commission, 2014).

3.3.8 Domestic DSM initiatives

Domestic DSM initiatives caused energy and climate policies to overlap, which resulted in confusion over which schemes and policies will continue, which will end, and what sort of new initiatives will be put in place. When the Electricity Demand Reduction (EDR) consultation proposals (Department of Energy and Climate Change and BEIS, 2017) were published, they interfered with then relevant energy policies, such as the Energy Efficiency Strategy, Energy Company Obligation, the Green Deal, Feed-in Tariffs (for electricity micro-generation technologies), the Renewable Heat Incentive (feed-in tariffs for heat micro-generation technologies), and climate policies, such as the Carbon Reduction Commitment Energy Efficiency Scheme (Warren, 2014).

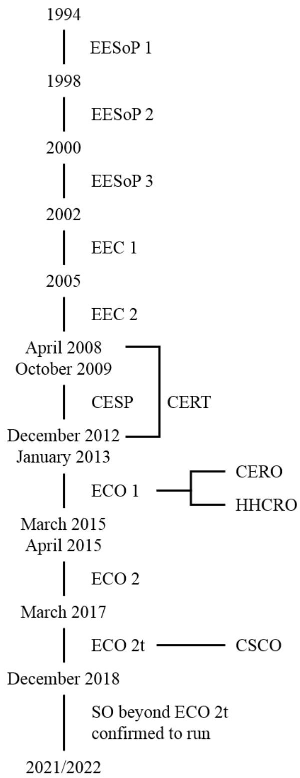


Figure 3.14: Development of the domestic Supplier Obligation from 1994 until 2021/2022

Regulatory DSM initiatives

The UK was the first country in Europe to impose energy saving obligations or supplier obligations (SO) in the residential sector on energy suppliers in 1994. The initial backing for the obligations' predecessor was fair, however, it was impossible to predict the SO would develop into the flagship climate policy for the domestic sector, delivering the largest proportion of the overall carbon savings (Rosenow, 2012).

Along with its predecessor, the Energy Efficiency Standards of Performance (EESoP), the SO have been instrumental for the increase of energy efficiency levels of the current residential building stock and the subsequent reductions in carbon emissions. EESoP, however, achieved considerably less carbon emissions reduction (Mallaburn and Eyre, 2014). For example, the Energy Efficiency Commitment phase 1 (EEC1) delivered four times as much as reduction in carbon emissions as EESoP 3 (Rosenow, 2012) making the SO, compared to other types of UK DSM policy, the one that stands out the most (Warren, 2014).

The timeline of previous and existing domestic regulatory DSM initiatives in the UK is visualised in Figure 3.14. Each initiative is further discussed in the sections below.

Energy Efficiency Standards of Performance

The predecessor to SO was called EESoP and was created by OFFER, with the help of the Energy Savings Trust (EST). The first phase, EESoP 1, ran from 1994 to 1998, followed by EESoP 2, running from 1998 to 2000. The first two phases applied to electricity suppliers only. In 2000, EESoP 3 extended the Obligation to gas suppliers as well (Rosenow, 2012). The EST advised OFFER, and later Ofgem, on how the targets should be set and what scale they should be. Suppliers met their targets by setting up schemes to promote energy efficiency measures, with the main types being insulation and lighting as well as heating and appliances. The energy savings achieved during the lifetime of the EESoP programme led to a carbon reduction of 4.4 million tonnes (Energy Saving Trust, 2003).

Energy Efficiency Commitment

In 2002, EESoP's name changed to Energy Efficiency Commitment (EEC). EEC, while differing in several important ways, built on the success and basic methodology of EESoP. Both EEC and EESoP had an emphasis on disadvantaged customers (Ofgem, 2017c). The Energy Efficiency Commitment phase 1 ran from 2002 - 2005 with an energy savings target of 62 TWh and achieving 86.8 TWh. The Energy Efficiency Commitment phase 2 (EEC2) ran from 2005 - 2008 with a target of 130 TWh and achieving 187 TWh (Warren, 2014).

Carbon Emissions Reduction Target

Due to the potential overlap of the SO scheme with the UK climate change targets, EEC was rebranded in 2008 as the Carbon Emissions Reduction Target (CERT) that ran until 2012 with a target of 293 Mt CO_2 (mega-tonnes of carbon dioxide) emissions reduction. The target was surpassed as energy suppliers achieved a 296.9 Mt CO_2 emissions reduction before the deadline of December 31, 2012 (Rosenow, 2012), (Ofgem, 2017c). The most common way for large suppliers to meet these commitments was through installing loft and cavity wall insulation in the premises of their domestic customers (Warren, 2014).

Community Energy Saving Programme

The Community Energy Saving Programme (CESP) was brought onwards in 2009 to run alongside of CERT in 2009, until its end in December 2012. CESP had an area-based approach focusing on more expensive measures (Rosenow, 2012). DECC set an overall carbon emissions reduction target of 19.25 Mt CO_2 by 31 December 2012. The target was to be met by making sure gas and electricity suppliers in addition to electricity generators would provide domestic consumers in certain low income areas of Britain with energy saving measures. Energy companies achieved a saving 16.31 Mt CO_2, almost 85% of the overall target (Ofgem, 2017c), (Think Insulation, 2017).

Energy Company Obligation

The Energy Company Obligation (ECO) is a government energy efficiency scheme in Great Britain to help reduce carbon emissions and tackle fuel poverty and was intended as a successor to CERT (Ofgem, 2017d). The scheme began in April 2013, undergoing various improvements and additions over its continued duration. The latest changes to the scheme occurred in 2017, and apply to measures installed from 1 April 2017. The latest version of the scheme is ECO2t. Beyond ECO2t the government has confirmed that a SO will run until 2021-2022 at least (Ofgem, 2017c).

Main ECO obligations

There are three main obligations under ECO to comply energy suppliers to achieve carbon and cost savings. Savings of 12.4 Mt CO_2 under the Carbon Emissions Reduction Obligation (CERO), 6 Mt CO_2 under the Carbon Saving Community Obligation (CSCO) (15% of which must be delivered in rural areas) and £3.7 billion under the Home Heating Cost Reduction Obligation (HHCRO) (Ofgem, 2015).

1. *Carbon Emissions Reduction Obligation* - developed for suppliers to promote 'primary measures', such as roof and wall insulation and connections to district heating systems. Some CERO must also be delivered in rural areas.
2. *Home Heating Cost Reduction Obligation* - forces suppliers to develop tactics that improve the ability of low income and vulnerable households to heat their homes. Any heating saving action falls under this obligation, even if it's boiler replacement.
3. ECO 2 also brought a further obligation called the *Carbon Saving Community Obligation*, which is achieved by promoting carbon saving community qualifying actions in areas of low income and rural areas (Ofgem, 2015). Suppliers were required to meet their CSCO targets by 31 March 2017 (Ofgem, 2017d).

Market-based DSM initiatives

Energy efficiency market transformation

The Market Transformation Programme covers all products that fall under the Ecodesign Directive. This is put into UK law by the Ecodesign for Energy Related Products Regulations (SI 2010 No 2617). Ecodesign regulations are geared towards decreasing the negative impact a product's life cycle can have on the environment by boosting the products' environmental performance. This is done through regulation or voluntary agreements. The products covered by the Ecodesign regulations and therefore the Market Transformation Programme include energy-using products, which use, generate, transfer or measure energy (electricity, gas, fossil fuel), such as boilers, computers, televisions, transformers, industrial fans and industrial furnaces (DEFRA, 2013b).

Economy 7

Economy 7 tariffs are differential energy tariffs making it possible for consumers to pay a different amount for electricity used at night compared to the electricity used during the day. For seven hours each night the unit costs for electricity will be lower than the unit costs paid during the remaining seventeen hours of the day (UK Power, 2017b).

Economy 10
Economy 10 tariffs (sometimes referred to as 'Heatwise') consist of 10 hours of off-peak electricity, which suppliers charge at a discounted rate (UK Power, 2017a).

Off-peak times are defined by each individual supplier and are spread across the day, allowing to add up to ten hours during each day, resulting in the name (OVO Energy, 2017).

Economy 10 is less widely supported than Economy 7, however, just like Economy 7 it suits best households with storage heaters (UK Power, 2017a).

Financial DSM initiatives

Feed-in tariffs for electricity micro-generation technologies
Generating their own electricity with the use of solar panels or wind turbines allows consumers to apply to receive payments from their energy supplier under the FiT scheme (UK Government, 2016b).

The FiT scheme is available for anyone who has installed, or is looking to install, one of the following technology types up to a capacity of 5 MW, or 2 kW for CHP (Ofgem, 2017f):

- Solar photovoltaic
- Wind
- Micro combined heat and power
- Hydro
- Anaerobic digestion (AD)

Renewable Heat Incentives
The renewable heat incentive (RHI) delivers feed-in tariffs for heat micro-generation technologies (Ofgem, 2017e).

<u>Domestic Renewable Heat Incentive</u>
The domestic RHI allows to obtain money for renewable heating costs in the participant's home and can be claimed for biomass boilers, solar water heating, and certain heat pumps. Payments are made for 7 years and are based on the amount of renewable heat made by the participant's heating system (UK Government, 2015c).

<u>Non-domestic Renewable Heat Incentive</u>
The non-domestic RHI is aimed towards businesses, public sector, and non-profit organisations to meet the cost of installing renewable heat technologies. The types of heating it entails are:

- Biomass
- Heat pumps (ground source, water source, and air source)
- Deep geothermal
- Solar thermal collectors
- Biomethane and biogas

- Combined heat and power systems

Payments are made over 20 years and are based on the heat output of the participant business' heating system (UK Government, 2015b).

Enhanced Capital Allowances (ECA)
The ECA scheme was designed to encourage a decrease of energy consumption and water by businesses. This was to be achieved by the businesses investing in the most efficient plant and machinery specified on the Energy Technology List (ETL), which is managed by the Carbon Trust on behalf of the Government (Carbon Trust, 2015). Such green investments could lead to decreasing overall energy costs and carbon emissions, aiding the UK's carbon reduction obligations, and encourage the sustainable use of water resources (UK Government, 2016c). The ECA scheme allows businesses to write off the whole cost of the equipment against taxable profits in the year of purchase. This can provide a cash flow boost and an incentive to invest in energy-saving equipment, which normally carries a price premium when compared to less efficient alternatives (Carbon Trust, 2015).

Micro-generation subsidies
The micro-generation subsidies came through FiT for micro-electricity generation and RHI for micro-heat generation (Ofgem, 2017g).

Voluntary DSM initiatives

Green Deal
The Green Deal was set up for domestic energy saving improvements and finding easier ways to pay for them. The improvements that could result in most energy saved depended on the household, but typical examples were:

- Insulation, e.g. solid wall, cavity wall, or loft insulation
- Heating
- Draught-proofing
- Double glazing
- Renewable energy generation, e.g. solar panels or heat pumps

Due to low interest and consequential poor take up, the Green Deal's government funding ceased in 2015 (UK Government, 2015d).

Information campaigns
Information and capacity building measures include utilities DSM/DR programmes and education, public outreach, and awareness campaigns. Their administration ranges from governmental agencies, regulators, local agencies, housing associations, and utilities, or else. In the UK, the EST is responsible for managing and consolidating all the information on available grants at all levels, and promoting partnerships for the supply of energy efficiency products, while still complementing other policies (Haney *et al.*, 2010).

Carbon Reduction Commitment Energy Efficiency Scheme

The CRC Energy Efficiency Scheme, or as it was previously known, the Carbon Reduction Commitment, was designed to improve energy efficiency and cut carbon dioxide emissions in private and public sector organisations that are high energy users (Environment Agency, 2014). Under the scheme fall supermarkets, water companies, banks, local authorities, and all central government departments. Any organisations meeting the qualification criteria must participate, and buy allowances for every tonne of carbon emitted. In the Budget on 16 March 2016, the Chancellor of the Exchequer, George Osborne, announced that the government has decided to close the CRC scheme following the 2018-19 compliance year. The motivation behind the closure was to streamline the business energy tax landscape by replacing it, in a revenue neutral way, with an increase in the Climate Change Levy. Organisations will report under the CRC for the last time by the end of July 2019 and surrender allowances for emissions from energy supplied in the 2018-19 compliance year by the end of October 2019 (UK Government, 2017d).

Energy efficiency strategy

November 2012 saw the beginning of the Energy Efficiency Strategy (EES) and the corresponding Energy Efficiency Deployment Office (EEDO) under DECC. The mission of the EES was to make the most out of the energy efficiency opportunity in the UK, which was deemed to hold too many benefits for the UK not to make it an important goal in the years to come. The EES was designed to maximise the benefits of policy already in place and to determine the wider potential energy efficiency could have across the UK economy. This was to be achieved through establishing connections between knowledge and technologies to fund, supporting energy efficiency innovation, and making more use of the energy efficiency information available (Department for Energy and Climate Change, 2013b). The first report was published in November 2012, and the second and last one followed in April 2013 (Department for Energy and Climate Change, 2013a). However, in 2015 EEDO was abolished.

3.3.9 DSM's role in the Electricity Market Reform

When the Energy Bill passed through Parliament in 2013 it failed to properly include demand side in the plans for the future electricity system, which was met with criticism. The Government then released an Electricity Demand Reduction consultation, which proposed three main market-wide incentives:

- A premium payment for electricity efficiency, which would provide participants with a payment in addition to the (potential) savings that result from reduced consumption;
- An energy supplier obligation for electricity efficiency in the non-domestic sector, which has so far only existed in the residential sector;
- Payments for participating in the capacity market.

The proposals for including the demand side in the capacity market are needed for the wider development of DSM in the UK electricity system, but it is unlikely that the residential sector will have a significant role in balancing markets due to the complexity of aggregators having to collate a large number of very small loads, the response of which may not be guaranteed due to the much greater number of decision-makers involved.

The potentially small amount of income that a resident could earn from participation is unlikely to warrant the effort and time required to reduce consumption when called on to do so and the risk of potential penalties for breaching contracts for not doing so. Incentivising the residential sector to participate in the capacity market would be a real administrative and commercial challenge, and other aspects of DSM policy, such as improved product standards, labelling and energy efficiency supplier obligations, may be more suitable approaches (Warren, 2014).

Following the EDR consultation, the Government developed the EDR pilot to determine how permanent reductions in electricity demand could be delivered via the CM, which seems to be the preferred option compared to payments and obligations. The Government tested whether projects that can bring lasting electricity savings during times of peak demand could at some point in the future compete for funding in the CM along with generation, DSM, and storage. These savings could be made with improvements to the motor or pump systems, LED installations, or other types of improvements to a building or electrical equipment, which would result in lasting peak-time electricity savings (Department of Energy and Climate Change and BEIS, 2017).

The pilot is being delivered across two phases. The first auction, held in January 2015, awarded £1.28 million in funds for savings to be delivered across the 2015-16 winter peak period. The second auction, held in January 2016, awarded funds totalling £4.74 million for savings from measures that were to be delivered in either 2016-17 or 2017-18 winter peak periods (BEIS, 2017h). The Electricity Demand Reduction pilot reports positive interim results (Stoker, 2017). In their report (BEIS, 2017h), BEIS revealed that after a number of bidders withdrew Phase 1 of the EDR pilot delivered 2.595 MW of demand reduction of an estimated 4.517 MW, resulting in a realisation rate of around 57%.

3.3.10 Current role of DSM in the UK

DSM's role in the capacity market

When the EMR was published, the demand side was omitted. It is possible for the demand side to participate through the capacity market and so far there has been some success, however, only industrial DSM has participated so far (National Grid, 2016a).

Aggregators contract with businesses when to turn off their activities and they aggregate the businesses under one aggregator which then competes in the CM. Domestic DSM or DSM envisioned under the EDR pilot doesn't participate in the capacity market.

In the most recent capacity auction, which concluded on December 8, 2016, DSM secured over 1.4 GW of contracts, which is an eight fold increase since the first CM auction back in 2014. BEIS has stated that the results provide certainty for businesses and consumers on security of supply. However, out of 1.4 GW of DSM secured, 1.3 GW of DSM is unproven (Virley *et al.*, 2016).

The transitional arrangements auction for DSM was held in March 2017 where a further 312 MW of DSM capacity was secured. This auction was specifically for turn down DSM, meaning diesel generators were unable to compete. The auction for capacity to be delivered in 2017-18 cleared at a price of £45/kW/year, with just 60 MW failing to win contracts (Bayar, 2017).

DSM's role in the balancing mechanism

The demand side already participates in the energy market through the balancing mechanism (BM). The BM's role is to balance supply and demand during peak times, which is primarily achieved with the use of back-up generation, which is often inefficient, high-carbon, and expensive to operate, as it is only used for a few hours per year (Bradley *et al.*, 2012).

The substitutes to back-up generation are electrical energy storage, interconnection, and to a limited extent, DSM. NGC had total requirements of 4.7 GW in 2011-2012 and it was estimated that 1.5 GW of DSM capacity was contracted, the majority of which was provided through on-site back-up generation with DR contributing only 200 MW (Department of Energy and Climate Change, 2013a), (Ward *et al.*, 2012).

Ancillary services can be provided through the Short-Term Operating Reserve, Fast Reserve, Firm Frequency Response, and Frequency Control. The 1.5 GW of existing DSM capacity contributes mainly to STOR and is provided through interruptible/curtailment contracts with large industries, which are paid to reduce energy consumption during peak times (Department for Trade and Industry, 2005), (Element Energy, 2012). Table 3.6 summarises the requirements for participation in the UK's Balancing Mechanism, and is collated from (Warren, 2014).

According to NG, STOR is required during certain times of the day when there is a need for reserve power in the form of either generation or demand reduction. This occurs when actual demand is greater than forecast demand and/or plant availability. If the scenario is cost-efficient, NG procures part of this requirement ahead of time through STOR (National Grid, 2017c). The conditions for participation include the provision of 3 MW or more of generation or demand reduction within four hours from instruction for at least two hours. Participants must have the ability to provide STOR at least three times a week and are given twenty hour 'recovery' time between service provision events. Typical loads of most electricity consumers are well below this 3 MW threshold and demand aggregators offer a service of contracting several smaller sites and to pass on their collective response capacity on to the system operator (Grünewald and Torriti, 2013). Frequency response is necessary when demand exceeds the frequency of electricity

Table 3.6: Requirements for participation in the UK's Balancing Mechanism

Balancing Service	**Minimum participation (MW)**	**Delivery time (min)**	**Sustained response (min)**	**Economic revenue (£/kW/year)**
STOR	3 (can be aggregated)	240	120	25-35
Fast Reserve	50	2	15 (at 25 MW/min)	40-50
Frequency Response	10	Automatic	-	50-55
Frequency Control by DSM	3 (can be aggregated)	0.03	30 (available 24 h/day)	-

supply, which is 50 Hz in the UK, causing a drop in frequency as generators slowdown slightly (Element Energy, 2012). This can occur as a result of inaccurate forecasts or a generation disruption event. Firm Frequency Response is an automatic change in demand or power output in response to frequency changes and DSM's contribution, such as through load management and the interruption of smelting activities, was 8% of the maximum requirement of 1200 MW in 2012 (National Grid, 2017d). The STOR average contracted utilisation payment from National Grid was 225 £/MWh in 2011, which is in addition to an availability payment of around 22,000 £/MW. The economic revenue from 3 MW of demand side participation in STOR would be 66,000 £/year (availability revenue) and £35,000 - £55,000/year, with utilisation revenue based on 50-80 one hour utilisation periods per year (Element Energy, 2012).

This shows that it is possible for utilities or separate DSM companies to aggregate reductions from different smaller loads to meet the requirements for entering the Balancing Mechanism. Despite this, although supply and demand side participation are treated equally, utilities often favour more traditional supply-side options due to the increased certainty of response unless the demand side response is automatically controlled and not overridden by the consumer. Thus, there is a role for policy support to increase the participation of the demand side as an economically efficient means of reducing total energy system expenditures (Warren, 2014).

3.4 Energy roadmaps and scenarios for Great Britain

There is a variety of scenarios dealing with different aspects of British energy that take previous developments and current policies and plans to try and predict the future of British energy. Scenarios have been a widely used analytic framing approach within the energy systems community. Approaches for planning Great Britain's energy future differ and the most relevant scenarios are listed and reviewed below:

- **Sectoral Scenarios for Carbon Budgets** by the Committee for Climate Change (Committee on Climate Change, 2015b)
  With the Climate Change Act 2008 (UK Government, 2008) the UK committed to reduce emissions by at least 80% based on the 1990 levels by 2050 and contribute to global emission reductions, to limit global temperature rise to as little as possible above two degrees Celsius. To meet these targets, the government has set quinquennial carbon budgets which currently run until 2032. They restrict the amount of greenhouse gas the UK can legally emit in a five year period. The UK is currently in its third carbon budget period (2018 to 2022). These reports primarily tackle how the UK deals with climate change, however, they include power sector scenarios (Committee on Climate Change, 2015a). Data is available for the two power sector scenarios included, which are called 'Barriers & Max' scenarios in 2030. Generation and capacity numbers are available, however, they are only included for the year 2030, limiting the amount of years during which the British electricity market could be studied. Historical power sector emissions from 1990 to 2014 and power sector CO_2 emissions as a percentage of total GHG emissions for the year 2014 are included as well. Expected costs of generation by technology for the years 2020, 2025, and 2030 are also available, along with plant retirements by technology to 2030. Although it includes information regarding GHG emissions not readily available at other sources, there isn't enough data available to be able to generate wholesale electricity prices for the year 2030 or any other year. The power sector report describes the impact of low-carbon generation on consumer bills. Overall, the report focuses less on the development of the power sector itself and more on the impact the power sector will have on greenhouse gas emissions and offers detailed output on the trajectory of the carbon price. The scenarios imply an emissions intensity at the upper end of the range of 50-100g CO_2/kWh, where low-carbon sources would provide around 75% of generation, including around 45-55% from renewable sources. The scenarios would position the UK power sector appropriately to meet the 2050 target at lowest cost. These scenarios were also used for the UK Renewable Energy Roadmap.

- **Renewable Energy Roadmap** by DECC (Department of Energy and Climate Change, 2011a)
  The UK Renewable Energy Roadmap replaced the 2009 Renewable Energy Strategy. The Roadmap outlines the actions the UK should take to meet its legally binding target to ensure 15% of electricity comes from renewable energy sources by 2020. It was released in 2011, with an update in 2012 and a final update in 2013 (Department of Energy and Climate Change, 2013b). The framework developed for renewable energy deployment had six key areas: facilitating access to the grid; ensuring long-term investment certainty; tackling pre and post consent delays; ensuring sustainable bioenergy feedstock supply; facilitating development of renewable generation supply chains; and encouraging innovation. In the Roadmap, renewable energy deployment predictions and costs were published. However, with the last update being in 2013, the Roadmap is no longer current. Additionally, it doesn't provide broader information regarding the development of the power system.
- **The UK energy system in 2050** by the UK Energy Research Centre (UKERC) (Ekins *et al.*, 2013)
  UKERC undertook a market allocation (MARKAL)-based investigation involving the generation of 2050 scenarios, under differing carbon and cost constraints. UKERC scenarios examine a wide array of possible developments, including various behavioural, technological, economic, and policy uncertainties. The majority of scenarios focused on the concerns around climate change. UKERC alternative scenarios investigate different drivers of the UK's energy supply and demand, and combine the twin goals of decarbonisation and energy system resilience. Future analysis includes the use of complementary macro-econometric and detailed sectoral energy models. The UKERC Energy 2050 low-carbon modelling produced two sets of model runs. A first set of scenarios focused on carbon ambition levels of CO_2 reductions (in 2050) ranging from 40% to 90% reductions. These runs also have intermediate (2020) targets of 15% to 32% reductions by 2020 (from the 1990 base year). These scenarios investigate increasingly stringent targets and the ordering of technologies, price-induced behavioural change and policy measures to meet these targets. A second set of scenarios undertake sensitivity analyses around 80% CO_2 reductions with the same cumulative CO_2 emission target, notably focusing on early action and different discount rates. These scenarios investigate dynamic trade-offs and path dependency in decarbonisation pathways. In the base reference Case, assuming that new policies/measures are not taken, CO_2 emissions in 2050 would be 583 MtCO_2, only 1% lower than 1990 levels. UKERC 2050 provides the biggest number of scenarios, which offer significant variability. The data (Ekins and Skea, 2011), (UKERC Energy Data Centre, 2010) provides primary energy demand, final energy demand by fuel and sector, the electricity generation mix, sectoral electricity demands and emissions, CO_2 and systems cost, and transport fuel costs in time steps of five years until 2050. Al-

though very detailed, the data used is primarily intended for resolving the sustainability question of the energy trilemma and there is less data available for questions regarding energy prices and market dynamics. For this reason, using consistent data and structure from the UKERC 2050 scenarios would not be sufficient to construct a model for the wholesale electricity market, unless obtaining remaining data information from other sources, which might impact the data consistency.

- **Energy and emissions projections** by BEIS (BEIS, 2017i)
  Updated energy predictions are published yearly by BEIS, offering an analysis and a projection for the future of energy use and greenhouse gas emissions in the UK. The projections are intended to help monitor progress towards meeting the UK's carbon budgets and to inform about energy policy and associated analytical work. The projections are based on assumptions of future economic growth, fossil fuel prices, electricity generation costs, UK population, and other key variables. Some indication of the impact of the uncertainty around some of these input assumptions is given. Each set of projections takes into account climate change policies for which funding has already been secured and where decisions on policy design are sufficiently advanced to allow robust estimates of policy impacts to be made. The only information disclosed about the models used is that the main model used is the Energy Demand Model, which is a mixed (top down/bottom up) econometric model of energy demand and combustion related greenhouse gas emissions for the UK economy. It is run in combination with other BEIS models which model retail electricity prices and the electricity supply sector. The projection of electricity generation is based on a model of supplier behaviour rather than statistical analysis of past trends. It reflects current policy up to 2020. The annexes provide future generation capacity and fuel, carbon, and wholesale electricity price predictions, which go until the year 2035. Final and primary energy demand are also listed, as are greenhouse gas emissions by source. Generation capacity isn't broken down in detail - for instance, renewable capacity isn't listed separately by type but grouped altogether making it difficult to study the impact of an individual renewable technology on the electricity market, which is of particular interest in this thesis.
- **Modelling the European Energy System (METIS)** by the European Commission (Chammas, 2017)
  METIS is an on-going project initiated by Directorate-General for Energy (DG ENER) for the development of an energy modelling software covering the whole European system for electricity, gas, and heat. The intention behind developing METIS was to provide the DG ENER with insights and robust answers to complex economic and energy questions with a focus on the short-term operation of the energy system and markets. METIS is a modular energy modelling tool covering the entire European energy system for electricity, gas, and heat with high granularity (geographical, time). Simulations adopt an hourly temporal resolution resulting in 8760 consecutive time-

steps per year. Uncertainties regarding demand and renewable power generation are captured thanks to weather scenarios taking the form of hourly time series of wind, irradiance, and temperature, which influence demand (through a thermal gradient), as well as PV and wind generation. The historical spatial and temporal correlation between temperature, wind, and irradiance are preserved. METIS includes European countries that are not EU members. The METIS market module is able to replicate the market participants' decision process. For each day of the studied year, both energy generation and balancing reserve supply, are first optimised based on the day-ahead demand and renewable generation forecasts. Market coupling is modelled via net transfer capacity (NTC) constraints for interconnectors. The generation plan is updated during the day, taking into account updated forecasts and asset technical constraints. Finally, imbalances are drawn to simulate balancing energy procurement (Bardet *et al.*, 2016). Detailed hourly results are also available for generation, fuel consumption, and CO_2 emissions (Chammas, 2017). METIS is a very comprehensive model, however, the data used to obtain results is not readily available. Since using a roadmap to provide the structure for the British wholesale market modelling is of interest in this thesis, an already-developed model without its input data available is less helpful when trying to meet the objectives of this thesis.

- **UK Scenarios for a Low-Carbon Energy System Transition** by the Energy Technologies Institute (ETI) (Energy Technologies Institute, 2015)
  To model the UK energy transition, ETI developed two scenarios named "Clockwork" and "Patchwork". The ETI scenarios differ from other scenarios listed as they focus on bioenergy, CCS, new nuclear generation, which are normally the less discussed technologies. The scenarios were modelled using Energy System Modelling Environment (ESME), which was designed within ETI and is an energy system design and planning tool. ESME covers the whole energy system for the UK, making it possible to look in detail at possible designs for infrastructure, supply, and end-use technologies for heat, electricity, personal transport, freight, industry, and so on. The Clockwork scenario offers long-term investments, which allow new energy infrastructure to be installed like clockwork. Nuclear and CCS enjoy high levels of support. In the Patchwork scenario, development is seen primarily on the regional level with the central government taking a secondary role. The role of renewables is key and there is more uncertainty over nuclear generation and CCS. Both scenarios offer somewhat detailed capacity predictions, however, there are no predictions for energy prices. Because the scenarios primarily aim to develop more options for the British energy infrastructure, the British electricity markets doesn't seem to play an important role, which is the main interest of this thesis, whereas capacity types that should be built are not.

- **GB power market model** by Aurora Energy Research (Aurora Energy Research, 2016b) Aurora Energy Research developed a model that is able to predict wholesale electricity prices for the British market and also includes interconnections with countries throughout Europe and are labelled dynamic dispatch models. The model claims to provide a comprehensive overview of the GB power market, including fully detailed descriptions of energy and climate policies, generation technologies, demand, and fuel prices. The models also forecasts electricity prices, spark spreads, dark spreads, future generation mix, and price dispersion. Aurora Energy Research introduces two scenarios: the "current IC" scenario and the "EC targets" scenario, which only differ in the interconnector capacity since Aurora models also estimate expected interconnector flows and their impacts on regional electricity prices. There are no details disclosed about the model given that it is a commercial model but in (Aurora Energy Research, 2016b) future British electricity prices are disclosed in a figure in addition to the future prices of countries Great Britain has interconnections with. Aurora doesn't make any other results of the model other than those in (Aurora Energy Research, 2016b) publicly available, however, this specific report includes predictions for interconnector flows as well. Due to this lack of public information on the model or data, the approach is not possible to replicate.

3.5 Chapter summary

This chapter summarised the types of low-carbon technology that are most likely going to play the biggest role in the British energy future and relevant policy related to them. Renewable generation already plays a significant role in the energy mix and the United Kingdom has established itself as one of the European leaders in renewable generation adoption. Bold targets for the future of renewable generation in the UK were established, however, they were largely influenced by the common European-wide targets. After the vote that took place on June 23rd 2016, which decided that the UK is to leave the European Union the answer to whether these targets will be reached on time remains less clear, however, the UK government stated that it remains committed to meeting them. The likelihood the targets will be met is increased due to the global commitment towards developing a low-carbon economy, such as the Paris Agreement, which puts more pressure on each individual country to be more mindful when installing additional generation. Participating in global agendas towards improving the energy system seems to focus primarily on renewable generation, however, demand side management and energy storage also have important roles to play if the transition into a greener energy system and the operation of it are to be smooth. The intermittent nature of renewable generation means we currently still have to use thermal generation to generate electricity when renewable resources aren't available, however, energy storage is being presented as a solution to this problem. With the correct implementation of demand side management policies that improve the workings of the entire electricity market and a drop in future costs of energy storage, the reliance on conventional generation could decrease over time and the prospect of a green energy system becomes much more real. The chapter concludes by reviewing the best known energy scenarios that each use different approaches to focus on various aspects of British energy and climate change.

Chapter 4

Modelling the British wholesale electricity market

In this chapter a merit order model of the British electricity market is presented. The model incorporates different types of renewable generation, demand side management, energy storage, and interconnectors with all the current and future countries Great Britain will have established electricity flows with. This chapter attempts to determine what the transition into a low-carbon technology system does to wholesale price fluctuations in the British electricity market, while minimising disruptions from intermittent resources.

4.1 Electricity price model

In previous work (Dunbar, 2016), an electricity price model was developed projecting British wholesale electricity market prices in the presence of wind generation. Additionally, commercial opportunities for energy storage through price arbitrage based on the determined market prices were explored. In this work, the merit order modelling approach as well as the method of differentiation of variable cost of types of generation technology was used as a platform to expand the model to address the issues the modern British energy system is facing and answer the questions regarding the future of the electricity market. For this purpose, a modelling approach based on the two previously mentioned methods is developed, incorporating the effect of the main drivers of the future energy world, namely all renewable generation technologies and not just wind as was the case in (Dunbar, 2016), interconnector capacities, DSM, and energy storage, which is unique to this thesis. While energy storage from a price-taking perspective has been addressed in (Dunbar, 2016) to determine the commercial opportunities for energy storage through price arbitrage due to increased wind penetration, the price-making approach used in this work is also suitable for future electricity markets with a higher amount of flexibility needed, which increases the impact of storage operation on market prices and thus requires the consideration of energy storage as a price-maker using dynamic programming unlike in (Dunbar, 2016), where linear optimisation was used.

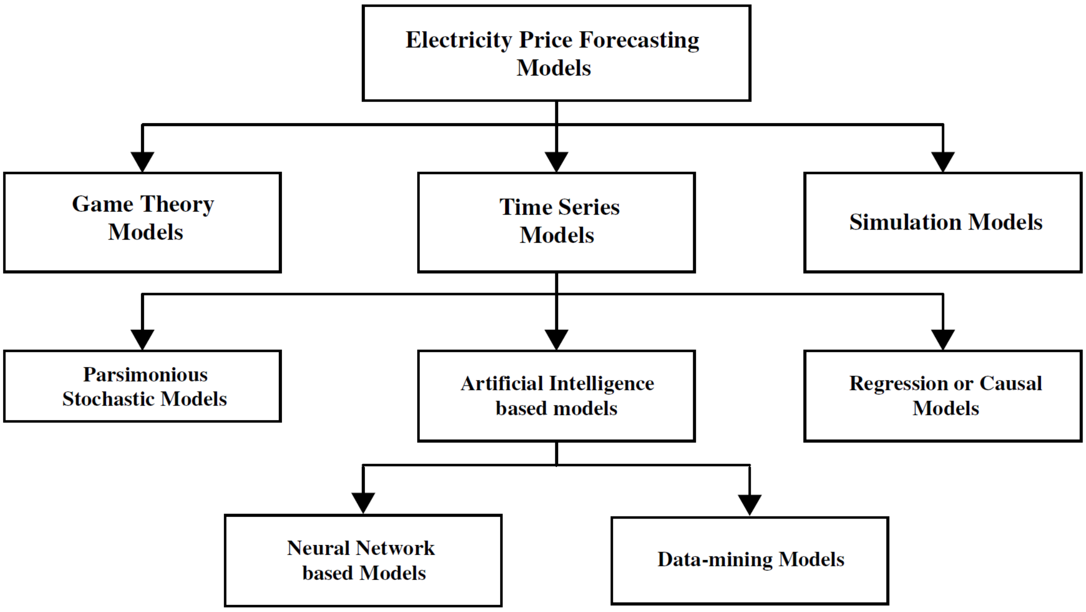


Figure 4.1: Breakdown of electricity price forecasting types (Aggarwal *et al.*, 2009)

4.1.1 Review of previous work

When it comes to price forecasting, most modellers focus on short-term price forecasting. This can be done using either using stochastic time series, causal models, or artificial intelligence based models (Aggarwal *et al.*, 2009). Artificial intelligence based models are then further broken down into neural network-based models and data-mining models, as seen in Figure 4.1. Stochastic models employ short-term characteristics of spot electricity markets, however, that limits their ability to offer an understanding of how prices are formed. Causal or regression models suggest that electricity price can be forecast using variables that seem to influence it and the price is modelled as a function of some exogenous variables (Shahidehpour *et al.*, 2002).

There are three categories of electricity price forecasting based on time horizons. Nonetheless, there are no strict time constraints in literature as to what the thresholds should actually be. These categories are (Weron, 2014), (Singh and Mohanty, 2015):

- Short-term forecasts can involve forecasts from a few minutes up to a few days and at most up to a week. Short-term forecasts benefit mainly the market players, which aim to maximise profits in the spot markets.
- Medium-term horizons can be considered from a few days, usually more than a week, to a few months ahead - normally no more than 12 months. They might be preferred for balance sheet calculations or risk management. Medium-term price forecasting allows for successful negotiations of bilateral contracts between suppliers and consumers.
- Long-term forecasting periods can vary from a few months up to a few years. Such forecasts play a role in transmission expansion and enhancement, generation augmentation,

and distribution planning.

In (Catalao *et al.*, 2007) a three layered feedforward neural network, trained by the Levenberg-Marquardt algorithm, is used to forecast prices for Spain. However, it is only possible to predict prices for the following week and not for a time period further in the future that would allow for a time span sufficient to witness a change in the energy system. Artificial neural networks were also used to predict the wholesale electricity market for Victoria, Australia (Szkuta *et al.*, 2002), however, like in (Catalao *et al.*, 2007), the predictions are only available for one week into the future. Further, the number of market participants is below ten. The training data was also only able to span one season of the year, which in the case of the paper was summer.

In fact, as discussed in (Weron, 2014), most price forecasting is performed for short-term to mid-term (half a year), periods. However, predicting electricity prices looking further into the future remains a less often tackled research topic. Since the rise of competitive electricity markets short-term forecasting has become increasingly important (Catalao *et al.*, 2007), however, it does not account for technology improvements, which is what long-term price forecasting includes and that is the reason long-term price prediction modelling was used in this thesis. Long-term price forecasting is also very important for investment and political decisions, long-term agreements, and strategic decisions. The long life time cycles of the generation units turn a wrong investment into a very expensive decision. It is essential to know the current state and the evolution of the different energy related markets and therefore top quality analyses are necessary to succeed in the energy business (Ercan and Soto, 2011). Long-term price forecasting plays a crucial and really important role on the planning for the construction of new generation facilities, on the development of a country electric mix and also on transmission lines (Esteves *et al.*, 2015).

In (Ziel and Steinert, 2017) probabilistic forecasts which are able to detect probabilities for price spikes even in the long-run are provided. However, these forecasts range between several months until up to three years, whereas in this thesis the price predictions are for much further in the future, until 2040. This allows for long-term capacity planning. In (Ziel and Steinert, 2017) the market used was the EPEX day-ahead electricity market for Germany and Austria. Lastly, the electricity prices were simulated with hourly resolution but in the model employed in this thesis half-hourly resolution was used.

Other examples include (Torbaghan, 2010), where medium-term electricity price forecasting was used to predict electricity prices in Canada's Ontario and Nord Pool. Here the lack of research in medium and long-term electricity price forecasting is also addressed. Generally, medium-term price forecasting has applications in markets for electricity with medium-term contracts such as forward/future contracts. Risk management and derivative market pricing, balance sheet calculations, and inflow of 'finance solutions' are a few examples of these applications. Since this is different from the uses and benefits of long-term price forecasting (Torbaghan, 2010) predicts electricity prices for Ontario and Nord Pool for 12 months in the

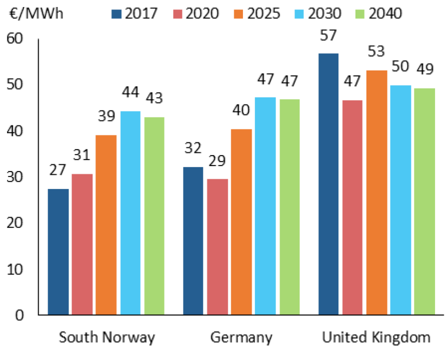


Figure 4.2: Future wholesale electricity prices in South Norway, Germany, and the United Kingdom, according to the baseline scenario (Statnett, 2016)

future. It is concluded that Support Machine Vector (SMV) models provide the most accurate results for the purposes of medium term-price forecasting. The forecasting accuracy is measured by using Mean Absolute Percentage Error (MAPE). Unlike short-term price forecasting, medium-term price forecasting and long-term price forecasting need models that are not based only on price data. The use of a SMV model allows for the inclusion of temperature data to predict the price of market of Nord Pool, which is useful for medium-term price forecasting but not so much for long-term price forecasting due to year to year fluctuations in temperature. SMV is also used in (Shiri *et al.*, 2015) and (Yan-Gao and Guangwen, 2009), where it is used to combine diverse influential variables to predict electricity prices; however, this is again performed on a short-term basis.

Another example of electricity price forecasting for Nord Pool data is (Beigaite, 2017). It is performed for short periods using price data for Lithuania's price zone in Nord Pool power market by applying Average, Seasonal Naive, and Exponential smoothing methods and also uses MAPE for accuracy evaluation. However, poor performance in the presence of price spikes is the main weakness of statistical methods since they do not excel at capturing spikes as well as the transition from workday to weekend day and vice versa. Additionally, MAPE might be misleading in the presence of close to zero prices (Weron, 2014).

However, long-term price forecasting in the Nordic countries has been performed by (Botnen *et al.*, 2017) from 2017 to 2045 and by (Statnett, 2016) from 2016 to 2040. Statnett (2016) also provided wholesale electricity prices for Great Britain and Germany and the predictions can be seen in Figure 4.2.

In (Ercan and Soto, 2011) a long-term price prognosis model is developed for France and encompasses the French hydro system. Although the production of other generation technologies is studied, the focus is on modelling the hydro generation in France and thus modelling other parts of the system is secondary.

Another short-term forecasting approach is presented in (Wu and Shahidehpour, 2010), where a hybrid time series and adaptive wavelet neural network (AWNN) model for the day-ahead electricity market clearing price forecast is developed. In this paper, instead of using price series, one-period continuously compounded return series are used for improved statistical properties. The autoregressive moving average with exogenous variables (ARMAX) model is used to determine the linear relationship between price return series and explanatory variable load series and AWNN is used to present the non-linear impact of load series on electricity prices. The Monte Carlo method is adopted to generate a more even random number distribution used for time series and AWNN models are used to accelerate the convergence. This work uses both, average mean absolute percentage error (AMAPE) and the variance of forecast errors to assess the model and measure the forecasting accuracy. The model uses the Pennsylvania-New Jersey-Maryland (PJM) interconnection as a case study.

In (De Marcos *et al.*, 2016) the Spanish electricity market price is forecast using co-integration and vector error correction (VEC) models, alongside other variables, such as fuel spot prices and futures prices. The work labels itself as a long-term electricity price forecast analysis, however, the accuracy of the forecast is limited to a period of one year in the future.

In (Green and Vasilakos, 2011), a market equilibrium model is used to calculate how the mix of generating capacity would change if large amounts of intermittent renewables would be built in Great Britain, and what this means for operating patterns and the distribution of prices over time. The research performed shows that significant penetrations of wind power will likely result in a decreased average electricity price. This is because of the minimal marginal price of wind power. However, an increase in range and variability due to its variable output of wind generation is expected. The paper concludes that year-to-year variations in wind speeds will have some impact on electricity prices and generators' profits, but these are smaller than those that have resulted from variations in fuel prices over the last decade. The research, however, does not account for any other renewable types. A similar approach is used in (Sáenz de Miera *et al.*, 2008a), where the long-run equilibrium impact of wind power on capacity and prices for up to two years in the Spanish market is evaluated. In (Cox, 2009), a model of the electricity system in Great Britain and Ireland is used in order to calculate operating patterns and prices for a scenario in 2030 which features high wind capacity penetration. However, the report available publicly does not disclose full modelling details.

The UK TIMES model was developed by the researchers at the University College London (UCL Energy Institute, 2017) and it describes the British energy system, from fuel extraction and trading, to fuel processing and transport, electricity generation, and all final energy demands. The model generates scenarios for the evolution of the energy system based on different assumptions around the evolution of demands, future technology costs, measuring energy system costs, and all greenhouse gases associated with the scenario. The UK TIMES model is a partial equilibrium energy system and a technologically detailed model, which is well suited to investigate the economic, social, and technological trade-offs between long-term divergent energy scenarios (Daly and Fais, 2014). Although it contributes significantly to determining how the future of British energy will unravel it does not do long-term electricity price forecasting.

As mentioned, long-term electricity price forecasting is a somewhat under-represented academic topic as it is primarily used in the industry and policy world since its main target is to aid with investment planning. However, other long-term forecasting is performed for instance for peak demand, as described in (Hyndman and Fan, 2010), which is important for planning for future generation facilities and transmission augmentation. Semi-parametric additive models are used to estimate the relationships between demand and driver variables, including temperatures, calendar effects, and some demographic and economic variables. The proposed methodology has been applied to forecast the probability distributions of annual and weekly peak electricity demand for up to 10 years ahead for South Australia since 2007. The results show good forecasting capacity of the proposed methodology at predicting the forecast distribution for the period proposed, however, discern that the type of methodology and the results needed might not result in high accuracy for periods further in the future.

The work reviewed in this section offers an insight into the current work being done in the field, however, more developed and specific work on the topic can be found on company, governmental, or system operator portals, as is the case here. The two sources that provided the most similar work were BEIS (BEIS, 2017d) and Britain's system operator, National Grid, as disclosed in their annual Future Energy Scenarios (National Grid, 2016b). In similar fashion, the long-term wholesale price predictions for the Netherlands were obtained from the country's statistics office (Schoots and Hammingh, 2016), proving once again that such predictions primarily aid in shaping the country's policy and investment decisions. Finally, (Aurora Energy Research, 2016b) forecasts future wholesale electricity prices in Britain and compares them to the forecast wholesale electricity prices of the countries Britain has interconnections with. The report investigates the long-term impact of interconnector capacity on the British power market. Although it is concluded that the introduction of 10 GW of additional interconnection could negatively affect both consumers and generators, the buildout of interconnector capacity would help lower wholesale electricity prices. In the two scenarios presented, the more interconnector capacity is built and connected with Britain, the lower the wholesale electricity prices due to the lower wholesale electricity prices on the continent.

4.1.2 Model rundown

The model is performing a market clearing in timesteps of 30 minutes and can be regarded as a model representation of the British spot market which is also cleared in blocks of 30 minutes. As the half-hourly time interval is the shortest in today's auction based market, publicly available data for demand, renewable generation, and interconnector flows is only available in this resolution. Even though a lower time resolution in the market clearing mechanism might become a reality in the future, the current data availability does not allow the implementation in the model as of today. For each half an hour a demand curve as well as a merit order was constructed, allowing the electricity price to be determined by market clearing, which assumes the point of intersection of the demand and supply curve. Thermal plants were stacked in merit order of increasing marginal cost to produce the thermal generation merit order. Since all generators of the same technology type were assumed to have the same bidding behaviour, an uniform technology merit order was used as the basis of the works such as (Evans and Green, 2005) and (Dunbar, 2016), as opposed to calculating individual generator supply functions. Although the model complexity was decreased from modelling individual power plants to modelling plant technologies, the approximation has been shown to be valid, after applying adjustments to the bidding cost within each technology using price uplift functions (Evans and Green, 2005). To form the net demand curve, renewable power power output and other non-dispatchable generation were subtracted from the electricity demand. This resulted in the dispatchable power still needed from the thermal generation. Since the UK Government ended subsidies for all new onshore wind farms and given that subsidies are planned to be phased out completely, renewable generation was assumed to have zero marginal generation cost (Department for Energy and Climate Change, 2015b). Net demand in the context of this thesis refers to the term "residual demand", which appears primarily in German research output (Steinke *et al.*, 2013), where residual load is defined as "the difference between actual power demand and the feed-in of non-dispatchable and inflexible generators". Residual or net demand is the demand that needs to be met by conventional thermal generation after available renewable capacity is subtracted from the total demand.

The model developed in this work incorporates thermal and renewable capacities between the years 2016 and 2040 to determine the impact of renewable generation on the future wholesale electricity prices, considering the interdependencies with emerging storage applications and increasing interconnection capacities. Figure 4.3 shows the breakdown of how the model operates.

The model does not include operational characteristics, which can have an impact on future investment and how much of each type of generational capacity is going to be built. If the renewable penetration is rather low the operational characteristics do not have a big impact on long-term prices as the operational characteristics of natural gas, coal, and nuclear are relatively similar and it is only when there is a lot of renewable generation in the energy mix that this becomes an issue. However, a trade-off has been made to look at a very long time horizon but still model renewable generation in a detailed manner, which not all models do. For example the previously mentioned UK TIMES has four intraday and four seasonal time slices and does not include wind variation (Dodds *et al.*, 2014). In such a framework it would be impossible to also look at detailed technical characteristics. If operational characteristics were included, the inclusion of half-hourly resolution would not have been possible and thus another trade-off would have had to be made. With low penetrations of renewables the effect of operational

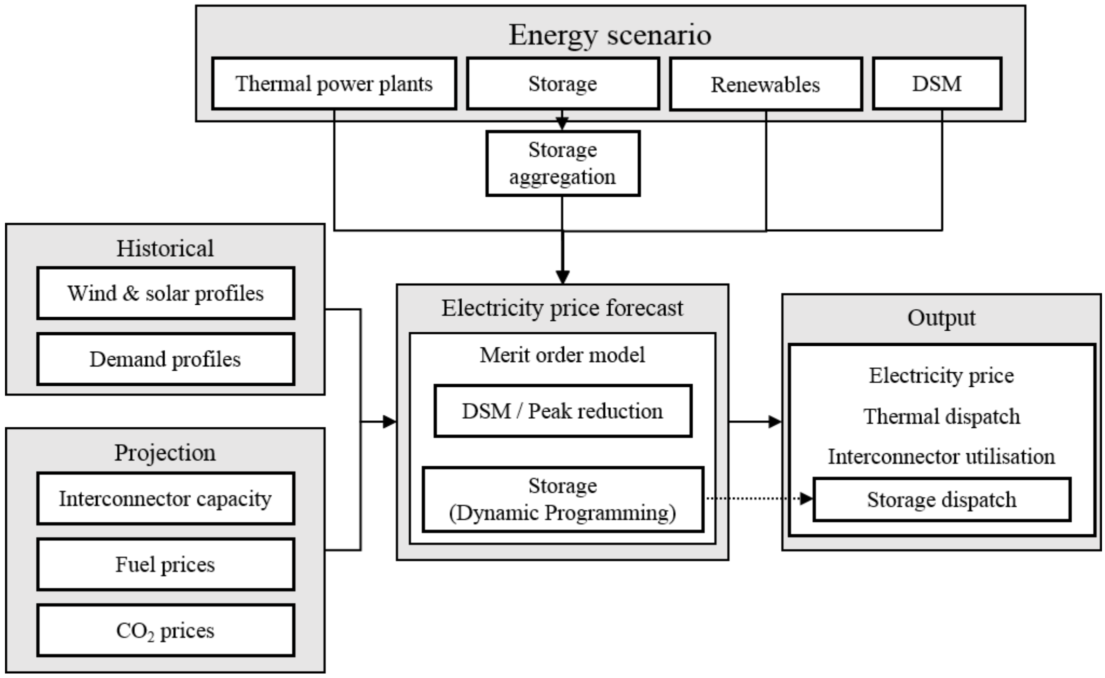


Figure 4.3: Model operation breakdown

exclusion is small but with larger renewable capacity the above trade-off was made in order to look at the temporal variation of renewables.

Thermal generation

The merit order was developed based on the input of electricity generation capacity, which was then stacked in order of increasing generation cost. In this model the types of generation that were input into the model were nuclear, coal, CCGT, and open cycle gas turbine (OCGT), each providing a price estimated based on the merit order bidding, which is at a price sufficient to cover the generation type's marginal generation cost.

Even though there is no Government regulation making it necessary for them to follow this bidding pattern literature suggests it is a valid approximation of behaviour in a competitive market (Boucher and Smeers, 2001), (Metzler *et al.*, 2003).

For each class of electricity generation, the price bid had a lower limit of its own marginal cost and the upper limit determined by the marginal cost of the next generator in the merit order, following the example set by (Grünewald, 2012).

The fundamental idea behind the merit order approach is that the electricity price is a function of electricity demand at that point in time, Equation 4.1. Depending on how high the demand is, different types of generation technology are required to meet the demand of which the most expensive technology sets the electricity price. Within one type of technology, due to different characteristics such as age, efficiency, fuel use, and unit size, every single unit has its individual generation cost. The prices are usually close to each other even though they are not exactly the same. The market clearing price paid to all participating generators was set by the highest merit order generator that was scheduled to run.

Price is defined as:

$$p = f(D) \tag{4.1}$$

In (Dunbar, 2016), different functions for the increase of generation cost within one technology of the merit order using an uplift factor were investigated. The prerequisite for these functions is the connection of the marginal cost of the respective technology when it is reached in the merit order and the marginal cost of the technology following next in the merit order. The comparison of the simulated price duration curves as well as the daily and weekly patterns with historical prices of the British electricity market showed that a hyperbolic price uplift function, seen in Equation 4.3 and an exponential price uplift function, seen in 4.5, prove to be most adequate to represent real market outcome for non-peaking and peaking thermal generation. Before the application of these formulas the current generation technology, which sets the market price, is determined based on the net demand of the respective point in time. If the price-setting technology is the last technology in the merit order, it is considered the peaker technology and Equation 4.5 applies.

Non-peaking:

$$p = C_{tech} \cdot uplift \tag{4.2}$$

In order to determine the market price, p, which results in a non-peaking technology setting the market price, the marginal cost, C_{tech}, of the respective technology is increased by an uplift function, Equation 4.2. The uplift is given by:

$$uplift = \left[1 + \frac{C_{tech+1} - C_{tech}}{C_{tech}} \cdot \frac{cosh\left(\frac{D - \sum_{tech-1} P_i}{P_{tech}}\right) - 1}{cosh(1) - 1} \right] \tag{4.3}$$

where C_{tech} is the marginal cost of the current technology in the merit order, C_{tech+1} is the marginal cost of the next technology in the merit order, and P_{tech} is the installed power/capacity of the current technology in the merit order.

By applying the uplift as defined in Equation 4.3, the resulting market price increases due to the hyperbolic function and reaches the marginal cost of the technology following in the merit order when reaching its capacity limit.

For peaking plants a similar uplift as for non-peaking plants is applied, Equation 4.4. The maximum price of the peaker plants is not limited by the final generator being dispatched so it bids higher to reflect scarcity of supply.

A price uplift bidding much higher than the marginal generation cost makes it possible for peaking plants that are usually dispatched only during the hours of the highest demand of the year to recover their fixed costs by bidding much higher than the marginal generation cost and can be observed in the British electricity market (Cox, 2009). This is considered by the exponential price increase, Equation 4.5.

Peaking:

$$p = C_{tech} \cdot uplift \tag{4.4}$$

with

$$uplift = \beta \exp^{\alpha \cdot (\frac{D - \Sigma_{tech-1} P_i}{P_{tech}})} \tag{4.5}$$

where α and β are constants, which were determined empirically in (Dunbar, 2016) and used to define the extent of the uplift applied when capacity was scarce.

4.2 Marginal generating cost

The operating costs for power plants comprise of fuel, labour, and maintenance costs and depend on how much electricity the plant produces. The operating cost required to produce an additional MWh of electricity is called the marginal generating cost.

Marginal electricity costs are the costs experienced by utilities for the last kilowatt-hour (kWh) of electricity produced. A utility's marginal cost can be higher or lower than its average price, depending on the relationships between capacity, generation, transmission, and distribution costs (Lawrence Berkeley National Laboratory, 2017).

In the case of conventional thermal power plants, today marginal generating costs are dominated by the cost of fuel. With the exception of biomass power plants in some instances, the cost of fuel is zero for renewable generation. For nuclear-powered plants the costs of fuel tend to be low and the cost of labour and maintenance makes up the bulk of the total operating cost. Most generators face a trade-off between the initial capital cost and recurring operating costs. Generally, the plants with higher capital costs have lower operating costs with nuclear being an example of that. The operating costs of all fuelled-driven plants are highly susceptible to changes in the underlying fuel price, which tends to be very volatile.

The marginal generation cost, which is the basis for the technology specific marginal cost in the merit order model, was calculated using Equation 4.6:

$$marginalcost = \frac{1}{\eta} \cdot \left(c_{fuel} + f_{emission} \cdot c_{emission}\right) + c_{O\&M} \tag{4.6}$$

Table 4.1: Utilisation factors (National Grid, 2016b)

Technology	Average availability, %
Hydropower	33
Biomass	77
Marine (wave, tidal)	22
CHP (maximum utilisation)	60

where η is the efficiency of the power plant, c_{fuel} is the fuel cost, $f_{emission}$ is the emission factor of the used fuel, $c_{emission}$ is the cost of CO_2/emission, and $c_{O\&M}$ is the operations and maintenance cost.

4.3 Demand

Historic demand data is available at National Grid's Data Explorer, where half-hourly demand time series are provided (National Grid, 2017e). Due to reasons that may be hindering larger scale DSM employment in Britain, which result in a lack of consumer flexibility regarding responding to changes in electricity price, zero price elasticity of demand was assumed for electricity. As demand data was in half-hourly intervals, demand and the electricity supply curve were calculated in the same time steps, with the point of intersection of inelastic demand and the supply function defining the electricity price at the time point. All the demand data from 2016 to 2040, such as the yearly demand, average residual demand, minimum residual demand, maximum residual demand, and minimum demand are available in Appendix B.

4.4 Renewable generation

Time series and historical capacities for offshore wind and onshore wind come from the European Meteorological derived high resolution renewable energy source generation time series (EMHIRES) database (European Commission, 2017d). The EMHIRES (wind) database is a set of data that models how much energy the current installed wind farms in Europe have produced in every hour during the last 30 years. Solar PV time series were obtained from the NG's Data Explorer portal (National Grid, 2017e). For renewable generation with a widely consistent output or with non-available historic generation profiles, that is, bioenergy, wave and tidal energy, and hydroelectric power, base generation profiles were scaled with utilisation factors found in NG FES (National Grid, 2016b) and listed in Table 4.1. It was assumed that if the renewable generation was available it was always utilised.

In some cases, the calculated net demand after subtracting the pre-calculated wind and solar generation profiles, as well as the base profiles that result from multiplying the utilisation factor from Table 4.1 with capacities, led to net demand peaks during the year, which exceed the available thermal generation capacity even after considering import from neighbouring countries to the full available amount restricted by the available interconnectors. In such instances the gap was covered with OCGT generation, since OCGTs have been historically used as peaker plants in GB (ICIS, 2012). The Government cannot allow for demand not to be met and as a result of that intervenes by designing instruments such as the capacity market to help fill the gaps.

The impact of replacing the missing generation with OCGT leads to an implied great reliance on natural gas-fired generation in the model. Furthermore, the assumption has an impact on the wholesale electricity prices during the hours of highest demand. However, due to the exponential behaviour of the price of the peaking generation technology, the added generation capacity is located at the top of the merit order, leading to high prices in line with prices in scarce situations on the market. Additionally, not filling the capacity gap would lead to much higher wholesale electricity prices, as in today's market where the price is capped at 3000 euro/MWh in situations where consumption cannot be met by the available generation bids (EPEX, 2017).

In this modelling approach, interconnector capacities are available to their full extent in scarcity situations in Great Britain, which represents an upper estimation to the real-world situation. It can be assumed that policy measures would be implemented before a situation where the generation adequacy of GB would depend on the availability of supplied energy from the neighbouring countries to a large extent or demand would not be supplied on the market. An implementation alternative would be including a maximum price cap, for example at 3000 euro/MWh, which however would not incentivise the required balancing operation by storage as it is implemented in this approach and would also distort prices to a large extent by adding runaway values into the time series. Thus, the chosen approach appears to have a less significant influence on the results and seems to be a more precise estimator to political actions undertaken to prevent these situations.

4.4.1 Demand and generation scaling

Following the approach used (Eager, 2012), the projection of future time series of both electricity consumption and renewable generation based on historic profiles required a scaling approach that accounts for changes in both the yearly energy sum as well as additional parameters given by scenario data while maintaining the fundamental shape of the base year, which ensures conformity with the other time series used. In case of electricity demand, energy scenarios usually assume a projected change in both total energy consumption as well as the peak consumption, which is most relevant when designing a suitable energy system. In order to scale the time series under these premises, a linear equation of the first degree with a general form formulated in Equation 4.7 is a common approach used. The average and peak electricity demand for each year studied in this thesis was provided by the case study documentation (National Grid, 2016b).

$$f(x) = a \cdot x + b \tag{4.7}$$

Applied to the problem of scaling electricity demand, Equation 4.8 is used to transform the value from the base time series $d_{t,base}$ into the value of the scenario time series d_t.

$$f(d_{t,base}) = a \cdot d_{t,base} + b = d_t \tag{4.8}$$

First parameter, b, of the linear equation is computed as a function of the average values of the base time series $D_{avg,base}$ and the future time series $D_{avg,goal}$ as well as the peak values of the base $D_{max,base}$ and future $D_{max,goal}$ time series using Equation 4.9.

$$b = \frac{\left(\frac{D_{max,goal}}{D_{max,base}} - \frac{D_{avg,goal}}{D_{avg,base}}\right)}{\left(\frac{1}{D_{max,base}} - \frac{1}{D_{avg,base}}\right)} \tag{4.9}$$

Using the parameter obtained in Equation 4.9, the second parameter, a, can be obtained using Equation 4.10, allowing the scaling after using Equation 4.9 and Equation 4.10 in Equation 4.8.

$$a = \frac{D_{max,goal} - b}{D_{max,base}} \tag{4.10}$$

When scaling renewable time series obtained from the EMHIRES model (European Commission, 2017d), the sole target value given from the case study future energy scenario includes the capacity value of the respective point in the future. Thus, in this case the second parameter, b, of Equation 4.8 can be set to zero, with only the base installed capacity and the scenario value for the installed capacity remaining in Equation 4.10 to scale the time series.

4.5 Interconnectors

Great Britain currently has two interconnections with Ireland, one to the Republic of Ireland, and one to Northern Ireland, one to France, and one to the Netherlands. Their characteristics are summarised in Table 4.2. Moyle has been operating at around half of its normal 500 MW capacity due to sub-sea cable faults since 2012 (Ofgem, 2017j).

Future connections are documented in a report by the (House of Lords Economic Affairs Committee, 2017) and on (Ofgem, 2017j). Publicly known interconnector projects in development can be seen in Figure 4.4 from (Science and Technology Committee - House of Lords, 2015).

Table 4.2: Existing interconnected capacities (Ofgem, 2017j)

Interconnector name	Developer	Connecting country	Capacity	Delivery date
IFA	National Grid Interconnector Holdings (NGIH) and RTE	France	2000	1986
Moyle	Mutual Energy	Northern Ireland	500	2002
BritNed	NGIH and TenneT	Netherlands	1000	2011
EWIC	EirGrid	Republic of Ireland	500	2012

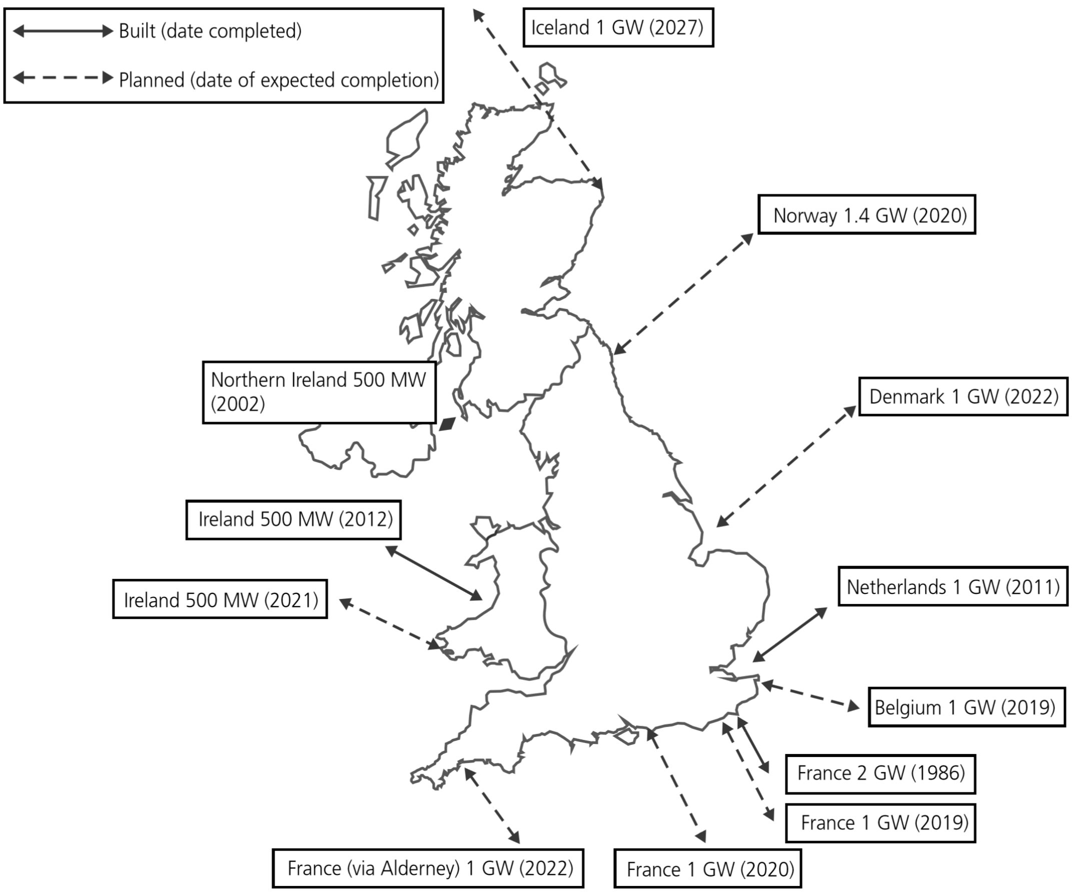


Figure 4.4: Current and future electricity interconnectors (Science and Technology Committee - House of Lords, 2015)

Including interconnectors in the model meant Great Britain could not be modelled as an islanded network and that the future price developments in connected countries need to be considered as available capacities in connected countries have a significant impact on simulated prices. In order to accurately portray the impact interconnection will have on the domestic wholesale electricity prices in Great Britain, flows with connected countries were modelled using capacity and the predictions for the future electricity prices in those countries. These prices were obtained from various sources. Prices for Norway and Denmark came from (Statnett, 2016). The Icelandic National Energy Authority was contacted, however, upon hearing back from them it was revealed they do not carry out any such predictions and do not plan to do so in the future. This is due to the fact that a wholesale power exchange is not established in Iceland, making it impossible to model the Icelandic power market explicitly. The Norwegian prices are used as a proxy instead, which is largely justified due to the fact both countries have similar cost structures and follow the example demonstrated in (Aurora Energy Research, 2016b). Further research showed that today's electricity price in Iceland is cheaper than in Norway (Copenhagen Economics, 2017), (Orkustofnun, 2004), thus the Norwegian price development has been adjusted to match today's price difference. The predictions for the future wholesale electricity prices for the Netherlands were obtained from the National Energy Outlook (Schoots and Hammingh, 2016).

To obtain the missing electricity price forecasts a price prediction approach using a simplified merit order model was developed for the electricity markets in Belgium, France, and Ireland. This approach follows the assumption that future electricity prices are mainly determined by the national thermal power plant portfolio, intermittent generation from wind and solar, and the national consumption. Thus, in this model, the demand after subtracting wind and solar generation is used to calculate the hourly marginal price of the most expensive technology required to meet demand. The merit order does not account for interconnection between the individual countries and the profiles for wind and solar generation are obtained from the two models published by EMHIRES (Gonzalez Aparicio *et al.*, 2017). The demand data for each country is published at European Network of Transmission System Operators' (ENTSO-E) E-Transparency platform and the normalised solar generation for France for 2015 can be seen in Figure 4.5 (ENTSO-E, 2015).

The development of capacities for thermal generation of nuclear, coal, and natural gas power plants as well as future capacities of wind and solar generation can be obtained from EU Reference Scenario 2016 (European Comission, 2016), which is available on a five-year basis. The EU Reference Scenario 2016 is a report focusing on the EU energy system, transport, and GHG emission developments, including specific sections on emission trends not related to energy, and on the various interactions among policies in these sectors. The yearly development of the installed national capacities is assumed to change linearly. The model output consists of hourly electricity prices for the respective countries. While the accuracy of the prices in each

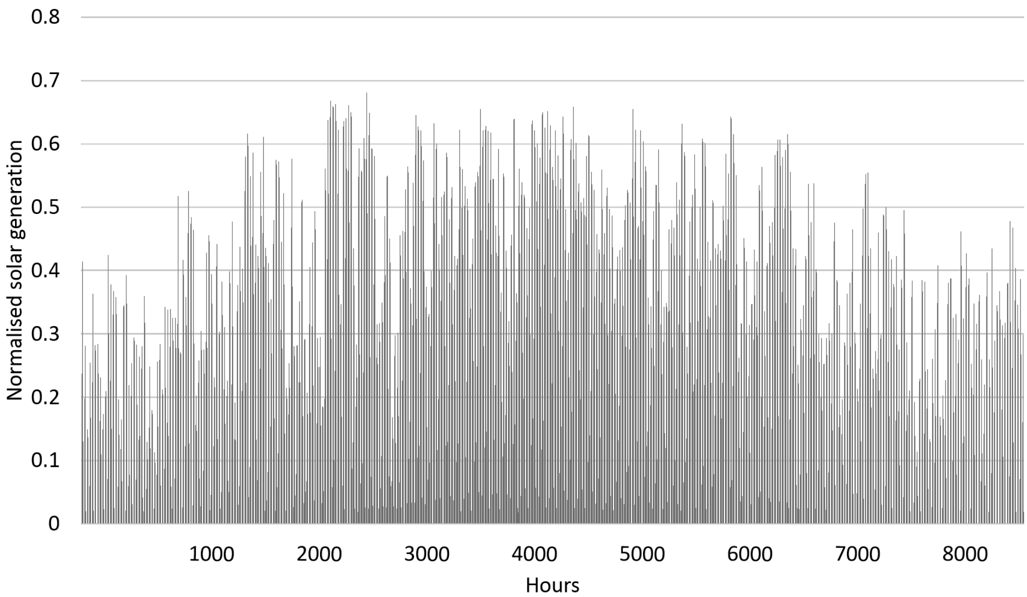


Figure 4.5: Solar generation in France in 2015 (ENTSO-E, 2015)

hour can be assumed to be relatively low due to the higher simplicity of the model compared to the model applied for calculating the British electricity prices, it can be assumed that it produces a sufficient estimation for the required yearly average price of the interconnection to the British market.

Interconnector capacity is expected to grow significantly in the future, having a substantial impact on the British electricity market, due to more connections with countries where energy mixes vary significantly from the one in Great Britain. There is a degree of uncertainty associated with using the predictions for the prices of electricity from the interconnectors. If the wholesale electricity prices from the connected countries would increase or decrease it would have a significant impact on the British wholesale prices. This is especially important as slow build in the Great Britain could lead to insufficient generating capacity in the future making Great Britain even more dependant on the price developments of electricity on the continent and in Ireland, making it heavily import oriented. The more Great Britain imports the bigger the uncertainty regarding the domestic wholesale electricity prices as it has to import from a larger variety of sources at times of high demand. However, all the wholesale prices of the countries where Britain is importing from also depend on a variety of factors that influence the prices and shift them in one direction or the other.

4.5.1 Interconnector modelling review

Foley *et al.* (2010) examine how market and meteorological effects could constrain interconnector operation in the all-Ireland system of Northern Ireland and the Republic of Ireland, where the variability of high levels of wind power generation have to be managed to ensure economic success and system stability. The paper uses the East-West interconnector between Wales and the Republic of Ireland as a case study. The papers investigates how the split between energy transfer and reserve provision through the interconnector will be dictated by energy prices and relative value of reserve services and how the levels of wind power generation in each connected region may limit the mutual support expected from interconnection.

Cleary *et al.* (2016) estimate the effects of large scale wind energy in the Irish and British electricity markets in terms of wholesale system marginal prices, total generation costs, and CO_2 emissions. The results indicate when the large scale Irish-based wind energy projects are connected directly to Great Britain there is a decrease of 0.6% and 2% in the Irish and British wholesale system marginal prices under the National Grid Slow Progression scenario, respectively.

Aurora Energy Research (2016b) assesses the impact that a build-out of interconnector capacity would have on the Great Britain power market. The model used to obtain the results is a dynamic dispatch model, developed to emulate the GB power sector in half-hourly granularity. It considers ramping costs and rate restrictions, and the stochastic availability of plants. It also includes the capacity market from 2018 onward. The key feature is the inclusion of endogenous IC flows, according to estimated gradient between GB and foreign electricity prices. The results highlight three key drawbacks of more interconnection. The first one listed is the costs that consumers incur, since IC subsidies are charge exempt. The second is the total European CO_2 emissions increase since natural gas-fired generation in GB is undercut by coal-fired generation in mainland Europe. Finally, it is concluded that more IC does not provide additional security of supply, as it displaces an equivalent amount of domestic baseload capacity.

Malaguzzi Valeri (2009) analyses the effects of additional interconnection on welfare and competition in the Irish electricity market. The wholesale electricity markets of the island of Ireland and Great Britain for 2005 are simulated. The amount of interconnection decreases for high costs of carbon, since this causes the markets to become more similar. This suggests that in the absence of strategic behaviour of firms, most of the gains from trade derive not from differences in size between countries, but from technology differences and are strongly influenced by fuel and carbon costs. Social welfare increases with interconnection, although at a decreasing rate. As the amount of interconnection increases, there are also positive effects on competition in Ireland, the less competitive of the two markets.

In (Tol and Malley, 2012) a mixed-integer, linear programming model for determining optimal interconnection for a given level of renewable generation using a cost minimisation approach is presented. Optimal interconnection and capacity investment decisions are determined under various targets for renewable penetration. The model is applied to a test system for eight regions in Northern Europe. It is found that considerations on the supply side dominate demand side considerations when determining optimal interconnection investment; interconnection is found to decrease generation capacity investment and total costs only when there is a target for renewable generation.

4.5.2 Conversion to determine intersection with the interconnector price

The case for interconnectors is based in large part on price differences between market areas, with Great Britain today typically importing from the lower-price markets on the Continent (Newbery, 2015). The market prices domestically and abroad in the interconnected countries determine that import to Great Britain is happening only when the prices on the Continent are lower, and export when they're higher than the prices in Great Britain.

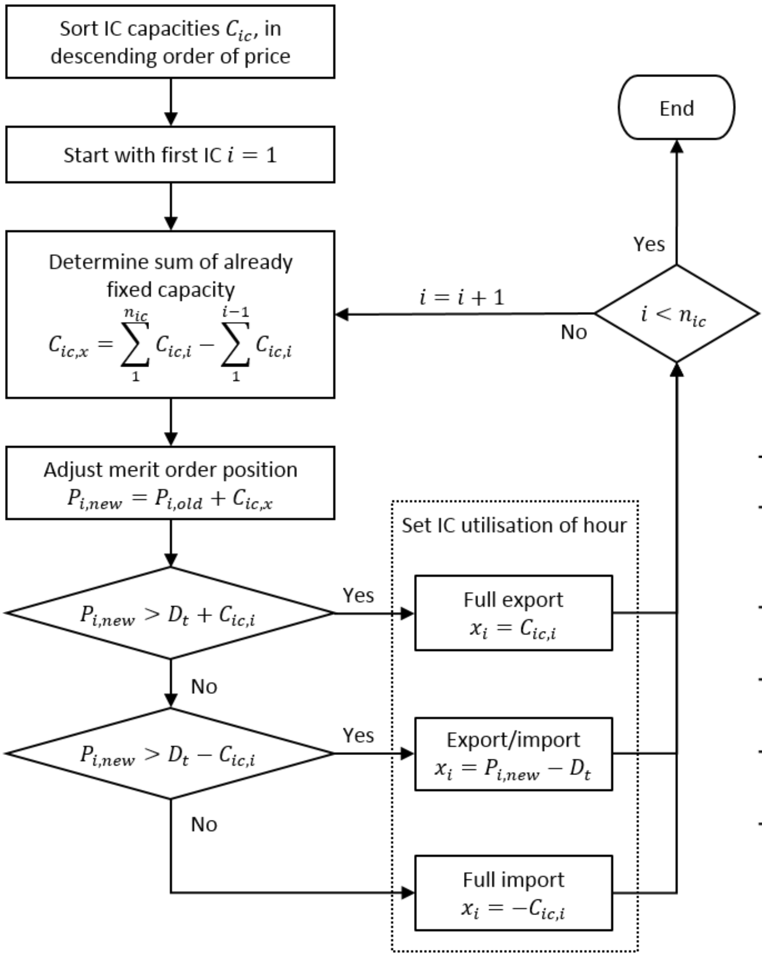
In order to include interconnectors in the model, instead of calculating a price based on demand left for thermal generators, the demand at the price intersection of the thermal merit order and the respective interconnector had to be calculated, thus the set of Equations 4.1 - 4.5 had to be reformulated into the form of Equation 4.11. The average yearly prices from interconnected countries were obtained from (Schoots and Hammingh, 2016) for the Netherlands, (Statnett, 2016) for Norway, Denmark, and Iceland and calculated for France, Belgium, and Ireland based on data from (European Comission, 2016). Based on that the demand had to be calculated to determine where the interconnected price falls into the merit order. For the interconnected prices below the marginal cost of peak generation, the reformulation of Equation 4.3 leads to the intersection demand in Equation 4.12. For interconnector prices above marginal cost of the peaking technology, in an analogous manner Equation 4.13 applies. The workflow demonstrating the process of interconnection modelling is shown in Figure 4.6.

$$D = f(p) \tag{4.11}$$

Non-peaking:

$$D = P_{tech} \cdot acosh\left(\frac{p_{IC} - C_{tech}}{C_{tech+1} - C_{tech}} \cdot (cosh(1) - 1) + 1\right) + \sum_{tech-1} P_i \tag{4.12}$$

where p_{IC} is the market price of the interconnector, C_{tech} is the marginal price of the current technology, C_{tech+1} is the marginal cost of the next technology in the merit order, $\sum_{tech-1} P_i$ is the sum of all installed capacities which are fully used (below the current one in the merit order), and P_{tech} is the installed capacity of the current technology in the merit order.



$C_{ic,i}$	Capacity of IC, i
n_{ic}	Number of ICs
$C_{ic,x}$	Aggregated capacity of ICs already included in the merit order
$P_{i,new}$	Adjusted merit order position of IC price
$P_{i,old}$	Merit order position of IC price
D_t	Net demand of time step, t
x_i	Utilisation of IC, i

Figure 4.6: Interconnection modelling workflow

Peaking:

$$D = \left[\log \cdot \left(\frac{p_{IC}}{\beta \cdot C_{tech}}\right) \cdot \frac{P_{tech}}{\alpha}\right] - P_{tech-1} \tag{4.13}$$

4.6 Demand side management

In order to meet greenhouse gas emissions targets the Great Britain future electricity supply will include a higher fraction of non-dispatchable generation, increasing opportunities for demand side management to help maintain a supply/demand balance (Drysdale *et al.*, 2015). During hours of peak demand DSM, by shifting or reducing capacity, can reduce the need for generation capacity, help with the integration of renewables, support more efficient system operation and thereby potentially lead to cost and carbon reductions for the entire energy system (Grünewald and Torriti, 2013).

4.6.1 Applications of DSM in literature

In (Khajavi *et al.*, 2011) incentive based DR programmes are introduced, the influence of smart grid on incentive based DR programmes is described considering the effect of Real Time Pricing, and incentive based programmes in the smart grid are analysed. Finally, the influence of a typical demand bidding programme is simulated on the load curve of a day in smart grid in the presence of RTP programme.

Grünewald and Torriti (2013) focus specifically on evaluating the empirical demand response data from the non-domestic sector. The nature of the response resource of consumers from different non-domestic sectors in Great Britain, based on extensive half-hourly demand profiles and observed demand responses are reviewed. The work goes further and explores the potential to increase the demand response capacity through changes in the regulatory and market environment. The analysis suggests that present DR measures tend to stimulate stand-by generation capacity in preference to load shifting and it is proposed that extended response times may favour load-based DR.

Torriti (2012) assesses the impacts of TOU tariffs on a dataset of residential users in Northern Italy in terms of changes in electricity demand, price savings, peak load shifting, and peak electricity demand at sub-station level. The results conclude that TOU tariffs result in higher average electricity consumption and lower payments by consumers and that a significant level of load shifting takes place for morning peaks. However, issues with evening peaks are not resolved and TOU tariffs lead to increases in electricity demand for substations at peak time.

Kim and Shcherbakova (2011) examine the central structural and behavioural obstacles to DR programmes succeeding and outline some potential solutions, which could greatly improve the functionality and success of such programmes in the future. The works concludes that the power sector's restructuring process, in its path to free market outcomes, often fails to encourage development of the same innovative programmes that can facilitate the transition to a free-market structure, such as DR programmes. Increased exposure to price risk and revenue uncertainty can result in capacity underinvestment. If the power sector isn't restructured escalating costs of peak generation, insufficient revenues from administered prices, completely decoupled from supply and demand effects, and a deteriorating supply security will continue to impact it negatively.

Finn *et al.* (2013) investigate the potential for demand side management to limit the requirement for curtailment and further facilitate the integration of renewable energy by shifting the timing of electrical demand in response to various signals including pricing and wind availability. A domestic dishwasher is used as an example. Significant increases in the amount of renewable electricity consumed are demonstrated with simultaneous financial savings for the consumer. Furthermore, secondary benefits such as peak-time demand reductions in excess of 60% are observed.

Aalami *et al.* (2010) focus on incentive-based demand response programmes including penalties for customers in case of no response to load reduction. The economic model is developed by using the concept of price elasticity of demand and customer benefit function. The proposed model helps the independent system operator to identify and employ the relevant DR programme, which improves the characteristics of the load curve. The model is evaluated simulating the load curve of the peak day of the Iranian power system grid in 2007. The impact of these programmes on load shape and load level, and benefit of customers as well as reduction of energy consumption are shown.

Logenthiran *et al.* (2012) propose a day-ahead load shifting technique, which is mathematically formulated as a minimisation problem. A heuristic-based evolutionary algorithm that easily adapts heuristics in the problem was developed for solving this minimisation problem. Simulations were carried out on a smart grid, which contained a variety of loads in three service areas, one with residential customers, another with commercial customers, and the third one with industrial customers. The simulation results show that the proposed DSM strategy achieves substantial savings, while reducing the peak load demand.

In (Girgis *et al.*, 2001) an optimal load shedding strategy for power systems with multiple types of distributed generation is presented. The dynamic and static models of each type of distributed generation following a major disturbance are developed. Based on the analysis of a major disturbance in either a grid system, interconnection or distributed generation system, the load shedding is formulated as an optimisation problem subject to system, operation, and security constraints.

In (Nguyen *et al.*, 2012) a DSM technique to reduce the peak load of the system is introduced, while considering a smart power system with distributed users that request their energy demands to an energy provider and the energy provider dynamically updates the energy prices based on the load profiles of the users. The users try to minimise the peak-to-average ratio of the power system by charging for their batteries at low-demand periods and discharging the energy during high-demand periods. A distributed DSM algorithm using a game theoretical approach in which each user tries to minimise its total energy cost is developed. In simulation results, it is shown that the proposed algorithm minimises the total energy cost.

4.6.2 Application

Peak reduction was employed to evaluate the effect DSM will have on the British electricity market. Peak reduction works by reducing the amount of energy purchased from the utility company during peak demand hours (Clifford Power, 2015). Similar work was performed in (Element Energy, 2012), however, the focus was only on the winter season for one year, whereas in this thesis all seasons in a year are analysed over a period of 25 years.

In every hour, t, renewables were first subtracted from primary demand to obtain demand that needed to be met by capacity, provided by thermal generation and interconnectors, $power_t$.

After renewables were subtracted from demand, the top 10% of all demand during the 8760 hours of a year were subject to demand reduction of $power_{shavemax}$ but limited to the 10% threshold, $power_{threshold}$. If a reduction of, for instance 4.5 GW of peak demand, would result in demand being decreased below the 10% threshold the reduction only occurred up to the point of the 10% threshold.

Equation 4.14 shows the formula developed and employed in the model:

$$peakreduction_t = min(power_t - power_{threshold}, power_{shavemax}) \tag{4.14}$$

$\forall\ power_t \geq power_{threshold}$

After employing peak reduction the resulting demand is defined by the reduced demand in the respective hour after subtracting the reduction potential, Equation 4.15:

$$power_{t,shave} = power_t - peakreduction_t \tag{4.15}$$

4.7 Energy storage

There is going to be more storage as part of the energy mix in Great Britain in the future, thus storage inclusion is seen as a perfect addition to an increase in capacity of volatile renewable generation. Energy storage dispatch is time-dependent and for this reason its direct inclusion into the primary merit order model is not possible. Storage operation is based on prices unlike thermal and renewable generation, which are based on demand/residual demand since the merit order model used in this analysis is not linear.

However, due to the increasing capacity and role of energy storage and the impact it has on the British electricity market, it must be taken into account. It has an important role to play as its inclusion allows for a significant reduction in peak prices (McConnell *et al.*, 2015), (Zafirakis *et al.*, 2016).

4.7.1 Problem solving approaches

To resolve the issue of storage and its incompatibility, various approaches can be used that account for the differences between storage and the rest of the merit order and still allow for the inclusion of storage, which is necessary to determine its impact on wholesale electricity prices.

In line with various other storage models such as (Graves *et al.*, 1999), (Xi and Sioshansi, 2014), (Butler *et al.*, 2003) perfect-foresight is assumed, under which prices are assumed to be known perfectly when making storage decisions. This assumption allows the value of arbitrage (and other) services to be estimated using historical price data and patterns (Xi and Sioshansi, 2014).

However, in (Sioshansi *et al.*, 2009), (Sioshansi *et al.*, 2011) the perfect-foresight assumption is relaxed by examining a 'backcasting' heuristic where storage is dispatched using historical price patterns that are assumed to repeat themselves. In (Sioshansi *et al.*, 2009) the arbitrage value of a price-taking storage device in the Pennsylvania-New Jersey-Maryland interconnection during a six-year period, to understand the impact of fuel prices, transmission constraints, efficiency, storage capacity, and fuel mix is analysed. The impact of natural gas and electricity price variation and volatility for pumped hydroelectric storage and compressed air energy storage is different and (Sioshansi *et al.*, 2011) explores these differences in operation and net revenue over a variety of timescales.

In (Xi and Sioshansi, 2014), a stochastic dynamic programming model is used that co-optimises the use of energy storage for multiple applications, such as energy, capacity, and backup services, while accounting for market and system uncertainty. Evaluating multiple uses of storage is important, given the high capital costs of most storage technologies. Most storage analyses that consider only one application find that storage is not economic on the basis of that single use. However, determining the value of multiple storage applications requires those applications to be co-optimised or else it can result in different storage applications conflicting with each other. In this paper the value of a battery that is installed in a residential home as a stationary storage device is studied and the study doesn't focus on utility-scale storage.

A stochastic dynamic programming model to maximise expected arbitrage revenues while accounting for energy price uncertainty is presented in (Mokrian and Stephen, 2006) focusing on the valuation of energy storage technologies through arbitrage profits within large scale power markets. Here, the assumption of perfect-foresight is relaxed unlike in this thesis. The focus is on the use of storage for intraday arbitrage and several models for optimising the operation of a storage facility over a 24-hour period are developed.

The use of storage to mitigate renewable variability and uncertainty is discussed in (Black and Strbac, 2007), (Paatero and Lund, 2005), (García-González *et al.*, 2008), (Costa *et al.*, 2008), (Bathurst and Strbac, 2003), (Black and Strbac, 2006), and (Black *et al.*, 2005) among others. In (Black and Strbac, 2007) the impact of uncertain wind forecasts on the value of stored energy (such as pumped hydro) in a future GB system, where wind supplies over 20% of the energy, is considered. García-González *et al.* (2008) analyse the combined optimisation of a wind farm and a pumped-storage facility from the point of view of a generation company in a market environment. The optimisation model is formulated as a two-stage stochastic programming problem with two random parameters: market prices and wind generation. The work done in (Paatero and Lund, 2005) investigates the effects of energy storage to reduce wind power fluctuations. Integration of the energy storage with wind power is modelled using a filter approach in which a time constant corresponds to the energy storage capacity. The results show that already a relatively small energy storage capacity of 3 kWh (storage) per MW wind would reduce the short-term power fluctuations of an individual wind turbine by 10%. In (Costa *et al.*, 2008) a virtual power plant, which uses a dynamic programming algorithm to operate an energy storage facility and a wind farm is described. Beyond that, (Bathurst and Strbac, 2003) describe an algorithm that calculates the combined optimal dispatch of an electrical energy storage facility taking into account the short-term power exchange and the expected imbalance position of the wind farm in the balancing market and investigates the effect of market and energy storage design parameters on average value. In (Black *et al.*, 2005) and (Black and Strbac, 2006) a new methodology to quantify the value of storage in the integration of intermittent wind resources is presented. The work provides quantified estimates of the potential value of storage, in managing the intermittency of wind generation, in the context of the future GB electricity system. Studies were developed to evaluate the benefits of storage for different applications such as providing standing reserve or in terms of savings in fuel cost. It was concluded that providing a greater part of the increased reserves needed from standing reserve in the form of pumped hydro storage increases efficiency of system operation and reduces the amount of wind power that cannot be absorbed.

In (Scott and Powell, 2012) the problem of developing near-optimal policies for an energy system that combines energy from an exogenously varying supply (wind) and price (the grid) to serve time dependent and stochastic loads in the presence of a storage device is addressed. The paper sets out to consider three different types of uncertainty in a stochastic control problem that arises when using renewable energy. The results show that Bellman error minimisation implemented in an approximate policy iteration algorithm outperforms least-squares policy iteration, but underperforms against direct policy search.

Marano *et al.* (2012) offer a model for thermo-economic analysis and optimisation of a hybrid power plant consisting of CAES coupled with a wind farm and a PV plant, which aims to overcome some of the major limitations of renewable energy sources. A mathematical model, validated in a previous study (Arsie *et al.*, 2005) over the CAES plant, is coupled with a dynamic programming algorithm to achieve the optimal management of the plant, in order to minimise operational costs while satisfying constraints related to the operation of reservoir, compressors, and turbines.

In (Staffell and Rustomji, 2016) a simple algorithm for storage providing arbitrage and reserve is demonstrated, which calculates the time profile of storage dispatch to give optimal profits. The results show that providing reserve can triple the revenue for storage in the British electricity market and with no foresight of future prices, 75-95% of the optimal profits are gained. However, the revenues are still not sufficient to justify the current investment costs for battery technologies, and so further revenue streams and cost reductions are required.

McConnell *et al.* (2015) explore the value of a price-taking storage device in an energy-only market, the National Electricity Market in Australia. The analysis suggests that under optimal operation, there is little value in having more than six hours of storage in this market; however, the inability to perfectly forecast wholesale electricity prices, particularly during times of extreme price spikes, would benefit from additional storage capacity. It is concluded that the provision of storage is similar to that of peak generators and is thus also dependent on and exposed to extreme price events, resulting in revenue for a merchant generator highly skewed to a few days of the year. It was also discovered that the variability of revenue and exposure to extreme prices could be reduced using common hedging strategies, such as those currently used by peak generators.

By using different energy trade strategies (Zafirakis *et al.*, 2016) determine the value of arbitrage for energy storage across European markets, considering PHES and CAES with a price-taking approach during a five year period. The results demonstrate that arbitrage opportunities exist in less integrated markets, characterised by significant reliance on energy imports and lower level of market competitiveness. The work also estimates the optimum size of energy storage systems in terms of arbitrage value for each different electricity market and evaluates the potential of arbitrage to support investment in the sector.

In (Pudjianto *et al.*, 2014) a whole systems approach to valuing the contribution of grid-scale electricity storage is presented. This approach simultaneously optimises investment into new generation, network and storage capacity, while minimising system operation cost, and considering reserve and security requirements. Case studies on the system of Great Britain with high shares of renewable generation demonstrate that energy storage can simultaneously bring benefits to several sectors, including generation, transmission and distribution, while supporting real-time system balancing. The analysis distinguishes between bulk and distributed storage applications, while also considering the competition against other technologies, such as flexible generation, interconnection, and demand side response. The paper also covers previous research done by the authors as it focuses on determining what are the cost targets, the scale of deployment, and what are the benefits of storage across different time scales and different sectors of the system. However, it does not research what impact storage would have on the electricity prices of the British power market.

In (Dunbar, 2016), linear optimisation of the storage operation was performed based on a price-taking approach. However, this approach is only feasible if the price effect of storage is not taken into account. However, given that storage is to play an important role in the future of British energy as it is featured in every energy scenario reviewed in section 3.4, this approach is not very accurate given that the merit order is highly nonlinear since change in demand has a varying effect on the resulting incremental price change. For example the differential is very high in situations of peak demand where the peaker uplift function applies while it is zero for a change within an interconnection capacity.

Other approaches have been employed to solve the bidding problem such as the mathematical programme with equilibrium constraints (MPEC) of which formulation is equivalent to the bi-level optimisation problem; however, the large struggle with MPEC formulation is solving it to optimality. To make the optimality gaps smaller, practitioners devise models based on Mixed-Integer Linear Programming (MILP) techniques, but since these are based on discretisation schemes they do not guarantee a global optimum either (Steeger *et al.*, 2014).

Another method is non-linear optimisation. However, it is impossible to optimise large time-coupled problems with non-linear solvers in an appropriate runtime, which is because of the insufficient performance of existing non-linear solvers (Steeger *et al.*, 2014). For the problem in the existing application the storage operation over an entire year should be calculated including both short-term as well as seasonal effects of price arbitrage. Because the problem being examined in this work stretches over many time periods, non-linear optimisation cannot be used.

For this reason this work implements a price-making, time-dependent storage operation optimising the revenue of an aggregated storage unit, by employing the method of dynamic programming, which is described in the following section. The succeeding section further provides the details describing the application of dynamic programming in this work and the resulting model. The time coupling between the present stage and future stages is resolved in the context of dynamic programming (and its variants) through the introduction of state variables.

In order to investigate the price development in the British wholesale electricity market for the case study, using the previously mentioned non-linear price demand function of the merit order with an half-hour time resolution dynamic programming is the most suitable approach among the mentioned ones. It combines fast computational times with the suitability for all kinds of price functions while including the effect of storage as a price maker.

4.7.2 Dynamic programming

Dynamic programming is a method that approaches solving optimisation problems that involve making a sequence of decisions by determining, for each decision, subproblems that can be solved in the same manner, thus leading to the optimal solution of the original problem composed from optimal solutions of the main problem's subproblems (Bellman and Dreyfus, 1962).

The method is based on Bellman's Principle of Optimality (Bellman, 1957):

> An optimal policy has the property that whatever the initial state and initial decision are, the remaining decisions must constitute an optimal policy with regard to the state resulting from the first decision.

More accurately, this principle goes on to state that 'optimal policies have optimal subpolicies'. The principle is built on the idea that if a policy has a subpolicy that is decreasing the chances of a positive outcome for the main policy, replacing that subpolicy with an optimal subpolicy, leads to an improved original policy. The principle of optimality is also known as the 'optimal substructure' property. Dynamic programming is concerned with the computational solution of problems for which the principle of optimality is given to hold. In order for dynamic programming to achieve a high degree of computational efficiency, especially such that is relevant to evaluating all possible sequences of decisions, subproblems should be common, such that subproblems of one are subproblems of another. In such an event, it is sufficient for a solution to a subproblem to be found only once and then reused as often as necessary (Lew and Mauch, 2007).

By breaking down a dynamic programming problem to subproblems, it leads to the problem itself being defined by its state at each time period and a set of such states is known as state space. Subsequent states are created when in each period decisions or actions are taken, resulting in the creation of a new state. Each action incurs a cost and/or a reward. The sequence of actions taken at each time step forms the final policy (Gil-Pugliese and Olsina, 2014). The process of a Markov multi-stage decision process is shown in Figure 4.7, demonstrating how new states result from existing ones.

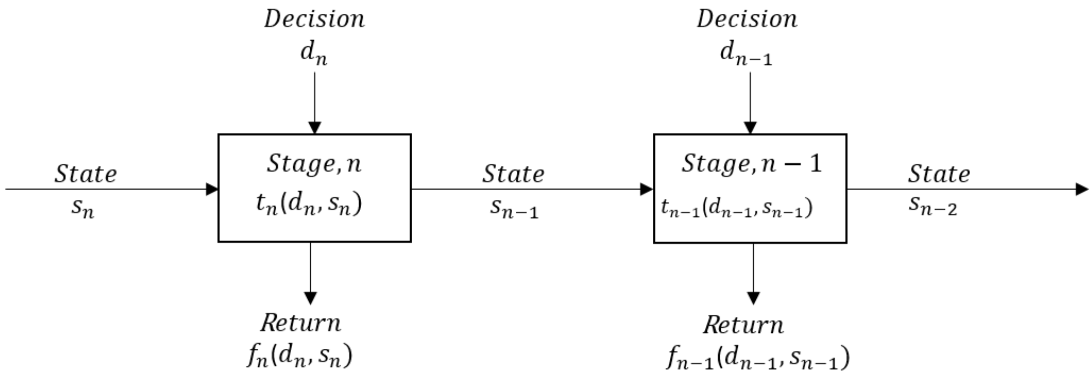


Figure 4.7: The multi-stage decision process adapted from (Hax, 1977)

Dynamic programming allows the approximation of the state space of a problem and with the use of backwards regression develops the policy, which ends up having the maximum global reward (White and White, 1989).

Applying this to energy storage, the state space can be defined with two dimensions - price of electricity and state of charge of the device, which can be approximated in steps, for instance 1 kWh. Then, a decision would follow on whether the device should charge or discharge, defined by the maximum amount of electricity which could be discharged per time step to the maximum amount of electricity which could be charged, represented by a discrete series of steps. As the number of states would increase, the dynamic programming model would expand, increasing the complexity of the problem, which is known as the 'curse of dimensionality'. This forces the algorithms to be limited to three or four state variables (Mokrian and Stephen, 2006). Due to the computational complexity, solvers are limited to Markovian processes - the probability of the next state is described completely by the current state without the history of state information (White and White, 1989). For a dimension like the state of charge this is not an obstacle, however, it poses a setback for the price model, which is most accurate when prices are modelled as a continuous process (Mokrian and Stephen, 2006).

4.7.3 Application

Dynamic programming allows only for one aggregated storage device as including multiple storage devices would lead to the 'curse of dimensionality'. At present this is not a problem since the only type of storage employed at larger scale in GB is pumped hydro storage. However, National Grid predicts a much wider variety of energy storage devices in the future British energy mix (National Grid, 2016b). In order to include these devices, they must first be aggregated. The aggregated storage operator which represents the entire storage portfolio included in the model is following a price-making approach under perfect foresight, optimising the revenue of its available storage unit in each time step during the entire year. The chosen microeconomic optimisation approach of the storage portfolio requires to maintain closing

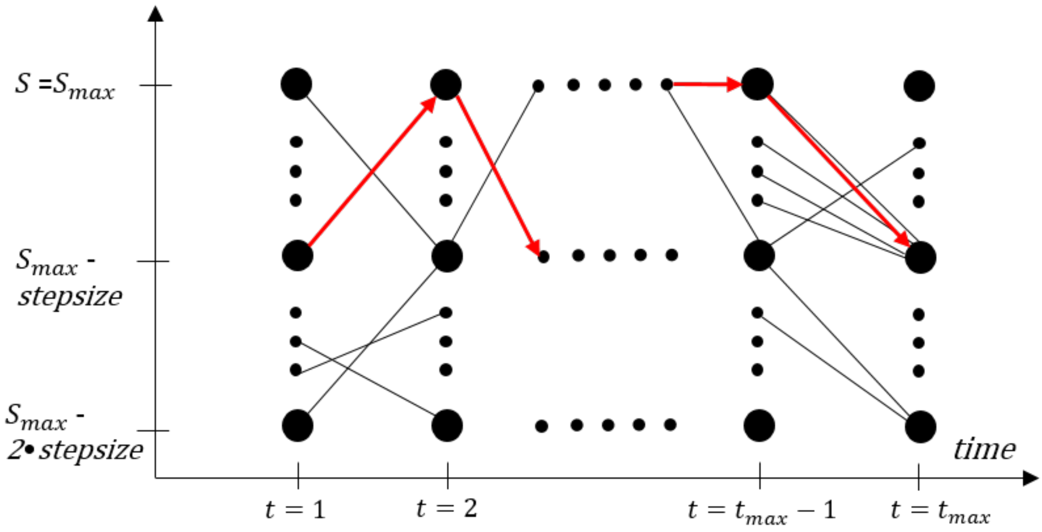


Figure 4.8: Visualisation of forward (red) induction

the capacity gap solely based on the available thermal capacity as revenue optimisation under perfect foresight would profit greatly from a non-functional market otherwise.

Among the storage technologies expected to have a direct impact on electricity prices, the two storage types with biggest predicted future capacity are pumped hydro storage and Li-ion battery. Another significant amount of capacity is expected from PV battery systems. These kinds of storage types, which are mainly expected to be used by end consumers, are operated with the goal of maximising self-consumption and do not respond to prices from the electricity market. Additionally, the small size of these individual systems does not allow a participation on the market as of today, thus changes in the market would be necessary to enable small consumers to participate. As such, a higher penetration of PV battery systems will have an impact on electricity prices to some extent due to the change in the future demand function. However, a strong influence due to direct interaction in form of price arbitrage on the market appears unlikely. As a result, pumped hydro storage as well as Li-ion batteries are included in the aggregated storage operator in this model.

The determination of the step size of the state space, which is in the case of storage operation the state of charge, is of major relevance for performing the dynamic programming approach developed. The choice represents a trade-off between the two desirable characteristics of the model, high computational performance with large step sizes and high accuracy of the storage operation with small step sizes. In the applications of the storage model a step size of 50 MWh_{el} was used, which represents a compromise between the required performance due to the performed multi-scenario, long-term calculations, and the precision required by the relatively quick changes in electricity prices due to the non-linear merit order.

The method of dynamic programming is a two-step approach which consists of backwards induction followed by a forward induction. The principle of DP is shown in Figure 4.8 in an exemplary manner. First, all possible states of the decision variable in every time step are mapped out as demonstrated by the black lines. Based on this the optimal decisions are computed by backwards induction, moving from the final step to the beginning in single step moves. After computing the optimal solution based on backwards induction, the optimal decision tree for a given initial state in the first step is chosen by forward induction, this time following the path of optimal decisions that was determined by preforming the backwards induction. In case of the optimal storage operation, the decision variable is the energy available in the storage unit. Both pumped hydro and battery storage are considered, rendering the decision variable to represent the amount of energy stored in the reservoir or the state of charge of the battery. The price of this variable is the profit of selling the generated electricity or buying the requested electricity, with the objective of maximising the unit's profit from the operation over the entire time horizon. Each storage state change results in a generation or consumption of electricity that as a consequence changes the required amount of energy being supplied by thermal power plants and thus has an adverse influence on the market price. This means that generating during high price time steps will lower the price and consuming during low price periods will increase the price, both making storage operation less profitable. If the effect of these price changes on the market price is considered, the approach is considered a price-making approach. Different to that is the price-taking approach, which assumes that the price effect of storage operation is negligible and thus includes no price change due to operation. In this application, the amount of storage can be considered very significant for the outcome of the future market scenarios, which does not allow for a price-taking approach without significant deviations from the price-making result. While price-making hydro dispatch is considered a problem difficult to solve in general, DP is considered an approach suited well for considering it. In this approach, the price effect of each state change on the price is considered by the merit order formulation. The default option of no change from the previous state means no hydro operation, meaning that the market price in the respective time step without storage applies, and for every other state in the solution map the individual price resulting after the change in demand is computed. This requires the merit-order calculation to be performed for each individual state of the solution map. As the size of the solution map increases with the amount of possible states, discrete step sizes of an adequate bandwidth are required. In this application, the storage volume of the aggregated storage operation unit is large as it is specified in section 5.7 and computational performance is an important aspect due to the variety of scenarios and the long time horizon. Thus the decision variable step size is chosen as 50 MWh_{el}. While the first step of DP does not require an initial state, an initial value for the first step of the forward induction is required which leads to the challenge of choosing a suitable initial value that does not lead to a significant deviation from a real-world solution. In this application, an initial storage state of 30% of the maximal storage capacity is assumed, which represents a compromise between avoiding essential dispatch in the beginning of the horizon due to an initial charging phase and preventing additional revenues from emptying the storage over the curse of the simulation. Since the path, which is displayed with red arrows in Figure 4.8, to maximise revenue was determined during backwards induction among all the possibilities between all the states, on the way back storage just follows the optimal decisions and thus maximises its possible revenue.

With regard to the implementation of the algorithm in this work, the state variable of the storage state in the previous time step S_{t-1}, which is being calculated in succession to the storage state of the actual time step in the backwards induction, is calculated as the sum of the storage state in t, S_t and the storage change due to the chosen operation in t, G_t.

$$S_{t-1} = S_t + G_t \tag{4.16}$$

The change of the storage state depends on the calculated decision option on the storage adjustment in t, S_t. In this case, a formulation is chosen where the roundtrip efficiency, η_{RT}, is fully accounted for in the charging operation process with negative generation, whereas the discharging process with positive generation is considered without losses.

$$G_t = \begin{cases} \triangle S_t \cdot \eta_{RT}, & \triangle S_t < 0 \\ \triangle S_t & \triangle S_t \geq 0 \end{cases} \tag{4.17}$$

Finally, the return of the decision option is the revenue in time step t,r_t. The revenue is a result of the decision option, which represents the additional generation or demand on the market, multiplied by the price of electricity, p. Following the price-making approach, the price is a function of the residual demand and the storage operation result, which is being evaluated by the merit order equations 4.1 - 4.5.

$$r_t = G_t \cdot p(D_t - \triangle S_t) \tag{4.18}$$

4.8 Model synopsis

The model, which was implemented in MATLAB consists of four sub-models. The principal idea of simulating electricity prices with a merit order model utilising uplift expands on the work done in (Eager, 2012) and (Dunbar, 2016), where the main research focus is assessing the value of electrical energy storage assuming a price-taking storage operation. The work considers whether more wind capacity would lead to more commercial opportunities for storage through price arbitrage. The merit order approach from (Dunbar, 2016) is used in this work to determine the market price resulting from the dispatch of the thermal generation.

To reach some of the objectives of this thesis, however, the merit order part of the model is developed further. For instance, (Dunbar, 2016) only includes wind generation in her work as the thesis focuses on the role of wind in storage arbitrage. However, in this model all main types of renewable generation are included - offshore and onshore wind, solar PV, bioenergy, marine energy, and hydropower. The goal of the entire model developed in this thesis is to simulate predictions for the future wholesale electricity prices of the British market with the inclusion of all low-carbon technologies of which impact on the market is investigated. The second sub-model adds interconnector capacities to the main model, no longer modelling GB as an islanded network as was done in (Dunbar, 2016) and other work that chooses to study the British market without consideration of its embedment in the European energy system. As future market price predictions for countries connected to GB or considered for connection in the future were not available in every case, simplified merit order simulations were performed using capacity data predictions and the main renewable energy sources. The third sub-model reduces peak demand in order to study the relationship between demand reduction and its impact on wholesale electricity prices in a future energy scenario, which also wasn't included in (Dunbar, 2016). The last sub-model tackles the optimal operation of energy storage in a system with a complex merit order considering the price effect of storage dispatch. In (Dunbar, 2016) storage was not modelled as a part of the merit order directly, but in a two-step approach of evaluating the optimal storage operation based on pre-calculated prices. For this, (Dunbar, 2016) used linear optimisation programming to study the impact of an aggregated storage unit following the price-taking approach. In this work, an integrated approach combining dynamic programming and the merit order approach considering the price effect of storage operation is used. Storage is thus modelled as an active market participant and its impact on the wholesale electricity prices is included and noted in the results. The model does not include CCS due to the limited development of the technology implementation in Great Britain. Furthermore, there is no policy in place that would indicate that is to change in the future. The CCS capacity is replaced by natural gas-fired generation.

The workflow of the model including all sub-models is depicted in Figure 4.9.

4.9 Model limitations

When predicting long-term future wholesale electricity prices, various uncertainties both from the choice of modelling approaches and the input data used arise, with one uncertainty of special relevance for the British market being the available interconnector capacities and their consideration in the model. While the medium-term development of interconnections is still predictable to some extent due to the long project development phase, the further, country-specific developments are subject to high uncertainty. This was resolved with the inclusion of the available interconnection expansion projects and further linear scaling for additional capacities assumed in the case study.

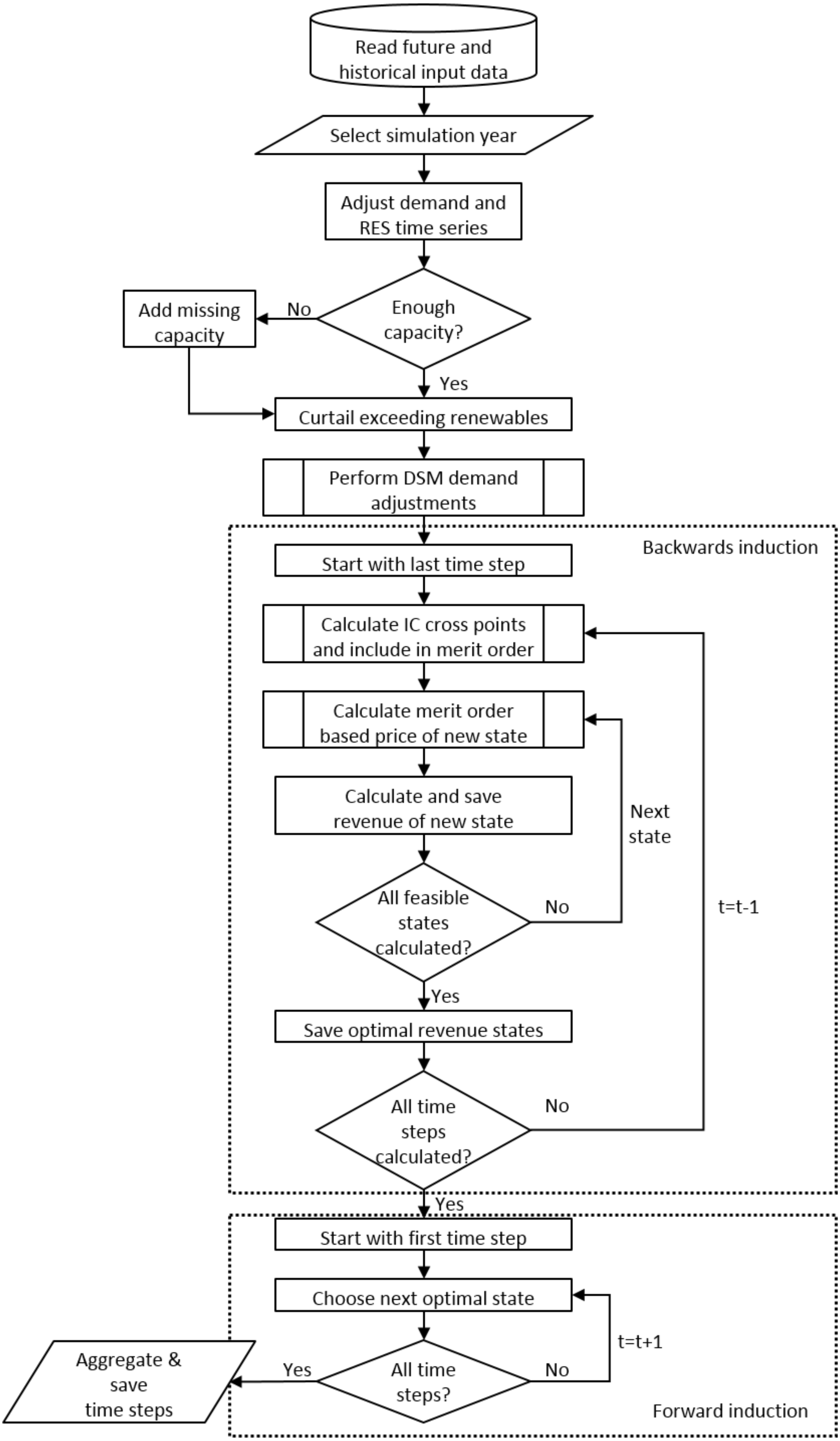


Figure 4.9: Model workflow comprising all sub-models

The model assumes full availability of interconnector capacities in times of high demand in Britain. However, as shortage might also occur in connected countries it can lead to potentially underestimating the resulting scarcity and wholesale electricity prices due to that.

Additionally, the wholesale electricity prices of the connected countries were averaged out during the year due to the lack of available work on predicting long-term electricity prices in connected countries. The result of this is missing the price pattern, which can lead to price dampening effects in the British market since electricity prices between connected countries are generally positively correlated due to the wide ranging factors such as temperature, wind speeds, and so forth.

Another limitation of the model is the fact it doesn't take into account responsiveness of prices when coupling electricity markets. In reality, import and export interconnector flows impact the wholesale electricity prices in the countries Great Britain has interconnections with. However, in this model the prices in these countries remain constant independently from the actual interconnector usage. This can have an impact on British wholesale electricity price predictions as it can lead to the price being dampened, as the reversed merit order effects in the interconnected countries are neglected.

Four groups based on different types of thermal generation were defined, as seen in (Grünewald, 2012) and (Eager, 2012). These were coal, nuclear, CCGT, and OCGT. However, there is a variety of power plants even in the same group based on the power plant operational characteristics such as efficiency, ramp rates, start up times, minimum generation levels, and in-load range, which were not accounted for. For present day simulations, using a data set which includes this information and a modelling approach accounting for many of them, leads to a more accurate reproduction of the real market behaviour. When looking multiple decades into the future and especially when looking at disruptive scenarios which assume a change of the entire energy system, changes in that power plant portfolio have to be assumed. In these cases, an endogenous investment model or statistically-based price differentiation approaches could be an alternative. In this approach, the uplift of technology prices is used to account for including the existing variation of the power plant generation cost. While the validity for future estimations is unclear, the validation of historic prices has shown promising results for this approach.

The base year used in the simulations is the year 2015, which is favourable in terms of input data due to an increasing data quality being demonstrated in last years but can also not be considered an average year due to a higher than average amount of wind generation (RenewableUK, 2017). However, the results of comparison simulations performed for the alternative base years from 2012 to 2014 show in section 5.8.1, that the base year does not have a significant effect on the resulting wholesale electricity price.

The solution to a DP problem requires only one pass through the DP to obtain the optimal policy for all possible realisations of the random process with DP taking into account a variety of decision stages as the problem size grows linearly in the number of states, making DP very useful for solving problems in which many decisions have to be made (Mokrian and Stephen, 2006). A major driver of short-term storage dispatch is the uncertainty, especially with regard to future renewable generation and the resulting decisions made under uncertainty. This is accounted for in many approaches of storage operation, the requirement for answering the research question in this approach however requires a high resolution long-term simulation horizon which prohibits the incorporation of uncertainty. However, it can be assumed that the ongoing improving quality of renewable generation forecast models will dampen the deviation in storage dispatch due to the perfect foresight to some extent.

4.10 Chapter summary

This chapter is composed of sections elaborating on different submodels, which all contribute to developing a model with the intention of producing long-term wholesale electricity price predictions for Great Britain. Interconnecting capacities are included as Britain isn't modelled as an islanded network. Firstly, a merit order was implemented, to see how the inclusion of renewables will influence the wholesale electricity prices. Second, the role of demand side management in the electricity market was evaluated to see how it can help the market cope with price peaks, reduce price volatility, and where it can play the biggest role in cost reduction with the application of peak reduction. Dynamic programming was used to determine the role of energy storage in a system that relies on renewable generation and demand side management. Figure 4.3 breaks down the model and shows the necessary steps to obtain the results presented in the following chapter. The following chapter presents and discusses the results of each analysis. The chapter follows the workflow order presented in Figure 4.9 that has also been established throughout the thesis. After the results are presented they are validated by comparing them to historical wholesale electricity prices and plotting them against prices from other long-term predictions sources.

Chapter 5

Results

Using the model detailed in Chapter 4 and a case study presented in this chapter results were obtained, detailing the impact of the case study on wholesale market prices. Wholesale electricity prices are simulated to determine the impact of each low-carbon technology on them, independently and jointly. The chapter also presents the results demonstrating the importance of interconnection on the British wholesale electricity market.

5.1 Data

Timeseries of offshore and onshore wind power and solar PV were used to obtain demand profiles and the capacities of other types of renewable generation are also included in the merit order model. The goal is to see what profiles of renewables will allow for the new capacity to be integrated to the established market with minimum impact on prices and variability.

5.1.1 Availability

In order to account for downtime when plants were undergoing planned or unplanned outages, mainly due to maintenance it was necessary to address availability. The technology-specific availabilities and plant efficiencies were obtained from (Robinson, 2016) and are detailed in Table 5.1.

The multiplication of the plant availability with the generator capacity led to a reduced yearly generator output. The likelihood of a shut down was constant during the year to simplify the

Table 5.1: Generation technology characteristics (Robinson, 2016)

Technology	Availability (%)	Efficiency (%)	Carbon emissions (kg/MWh)	Variable operating cost (£/MWh)
CCGT	92.6	60	185	2.2
OCGT	94.7	37	185	2.7
Coal	90.8	41	285	2.0
Nuclear	91.1	36	0	1.8

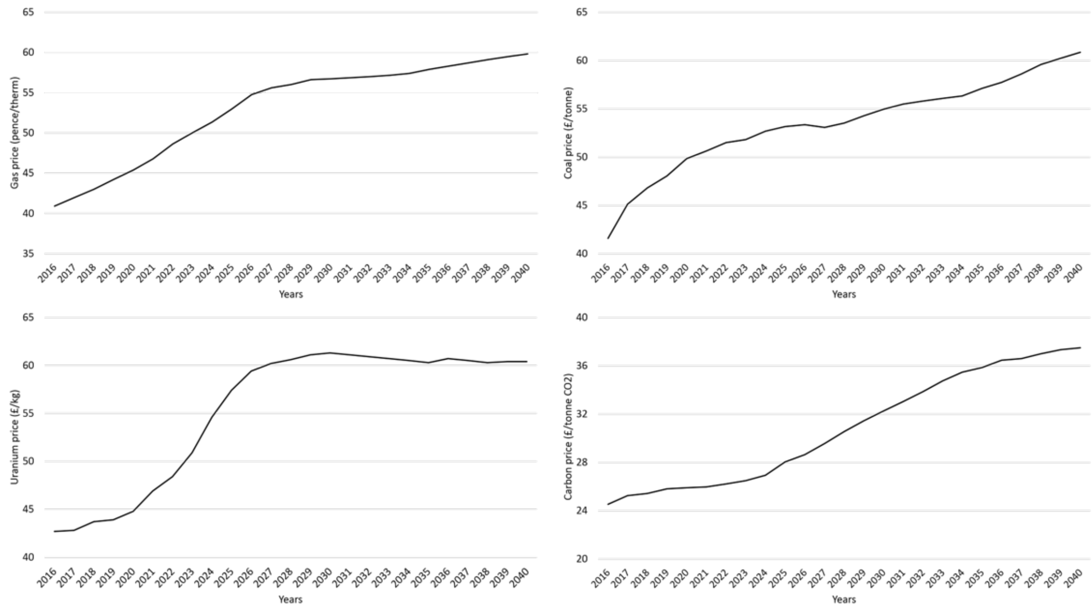


Figure 5.1: Clockwise: predictions for natural gas (National Grid, 2016b), coal (National Grid, 2016b), carbon (National Grid, 2016b), and uranium (TradeTech, 2017a) prices between 2016 and 2040

model even though there is an increased chance of planned maintenance during summer as plant operators aim for a minimisation of lost earnings from the market and as wholesale electricity prices are historically lowest during the summer. Furthermore, future availability was assumed to remain at today's rates for each technology and every year included in the model.

5.1.2 Fuel costs

Volatility can be observed in all types of fuel markets as they're exposed to different regulation implementation in every country, political distress such as war, unpredictable weather conditions, and natural disasters. Changing demand and supply also leads to increased volatility as does speculation about future prices and the monopolistic structures of a few large producers as is the case with oil and the Organization of the Petroleum Exporting Countries (OPEC).

Fuel and carbon prices were obtained from (National Grid, 2016b), with the exception or uranium, which was obtained from (TradeTech, 2017a) and are displayed from 2016 to 2040 in Figure 5.1. Fuel costs used to generate the results are included in Table B.1 in Appendix B.

Gas

Yearly natural gas prices were found in National Grid's FES (National Grid, 2016b). Although the natural gas price is considered rather volatile and can change significantly within a year, thermal generators have contracts that agree on a natural gas price with their providers for years to come for this specific reason. This is why annual natural gas prices were considered sufficient for this model's purpose.

Coal

Future coal prices were made available for each year until the year 2040 in FES (National Grid, 2016b). Historical coal prices are published in BEIS reports as Quarterly Energy Prices (BEIS, 2017e).

Nuclear

Nuclear prices were not included in the FES and thus the NUEXCO exchange values were used instead (TradeTech, 2017a). NUEXCO is the longest running uranium price indicator in nuclear fuel history and its monthly uranium fuel prices are published by TradeTech (TradeTech, 2017b).

Carbon prices

Harmful carbon emissions are the by-product of reliance on thermal generation. Like fuel costs, carbon prices are volatile as they depend on the political climate. They are considered as a surcharge to thermal electricity generators to compensate for their pollution and are thus included in the variable cost of power plants. Future carbon prices were provided by NG in FES (National Grid, 2016b).

5.2 Model validation

To validate the model the historic year 2015 was compared to the simulated results from the model for the same year. The year 2015 was also chosen as a base year for generating future wholesale electricity prices, using historic time series from the year.

Figure 5.2 displays the comparison of the historic 2015 prices against the simulated wholesale electricity prices for the same year plotting the historic prices against the simulated ones for each month of the year. The figure shows that in the winter months from November to February the simulated prices were calculated as higher on average compared to the historic ones. This difference can partially be attributed to the different handling of planned outages compared to real power plant operation. This also explains the opposite effect from April to October where

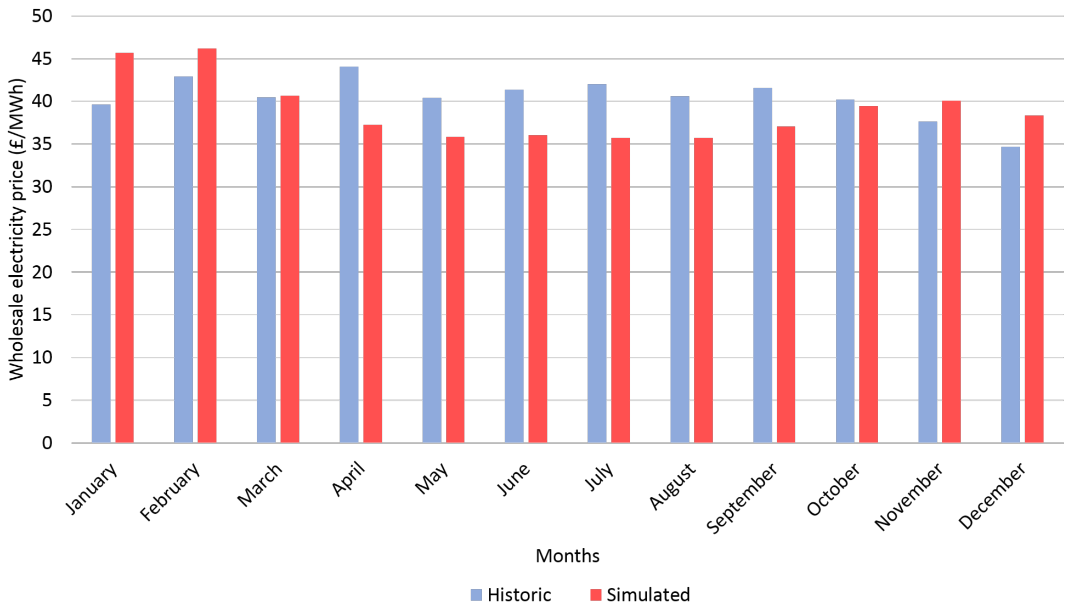


Figure 5.2: Comparison of historic versus simulated prices for every month for 2015

the simulated prices are lower than the historic prices. However, the differences between the historic and simulated prices are rather small with the prices being the closest in March and with the biggest difference being in April where the difference is about 6 £/MWh.

Figure 5.3 shows how close the simulated prices for every day of the week come to the historic ones. The simulated prices are always smaller, however, the biggest difference is on Saturday and Sunday. Saturday and Sunday are usually low demand and thus low price days, so they fall often in the lower part of the duration curve, which is reflected in lower average prices compared to the ones observed in reality.

Figure 5.4 displays the price duration curves for both the historic and simulated wholesale electricity prices in 2015. Although the simulated prices don't reach prices as low as the historic ones for most of the duration the two price curves look pretty similar. The other difference is that historic peak prices are lower than the simulated peak prices. Prices close to zero mostly come from technical constraints of power plants which forces them to bid for prices below their variable operating cost. These are not fully included in the model, thus it is expected to see a deviation at the bottom end of the curve. The deviation at the top end is largely influenced by mark ups due to generation scarcity. Additionally, the approach used tends to overestimate the interconnector price and availability.

Figure 5.5 plots the historic prices for every hour in February 2015 and compares them to hourly prices for the same month simulated. For the first half of the month the simulated prices were actually projected as higher than the historic prices with the peak in simulated prices at hour 258 and the simulated price of 115.3 £/MWh being significantly higher than the historic

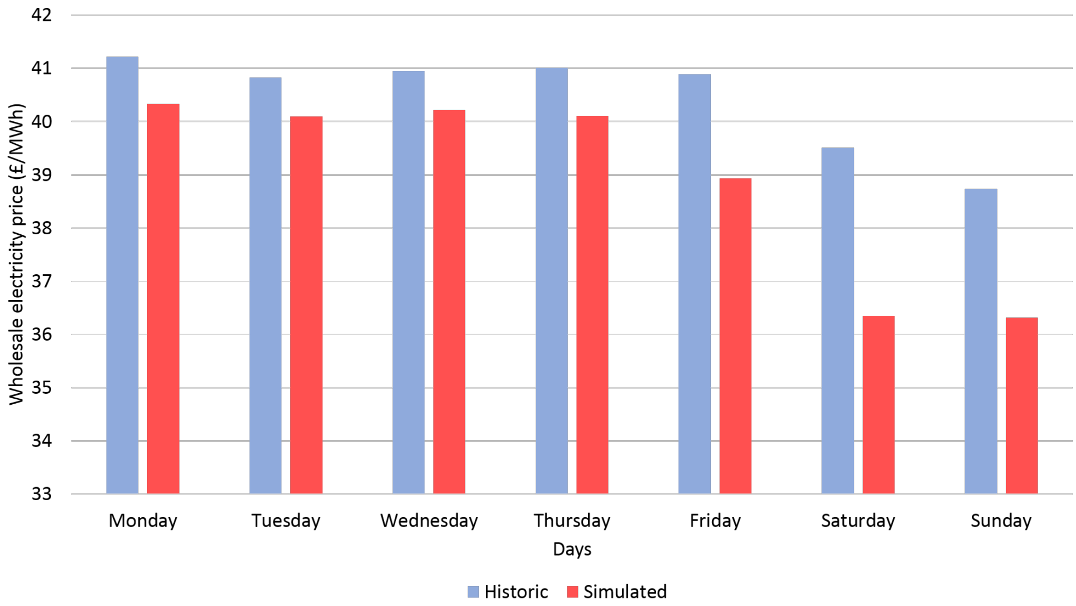


Figure 5.3: Comparison of historic versus simulated prices for every day for 2015

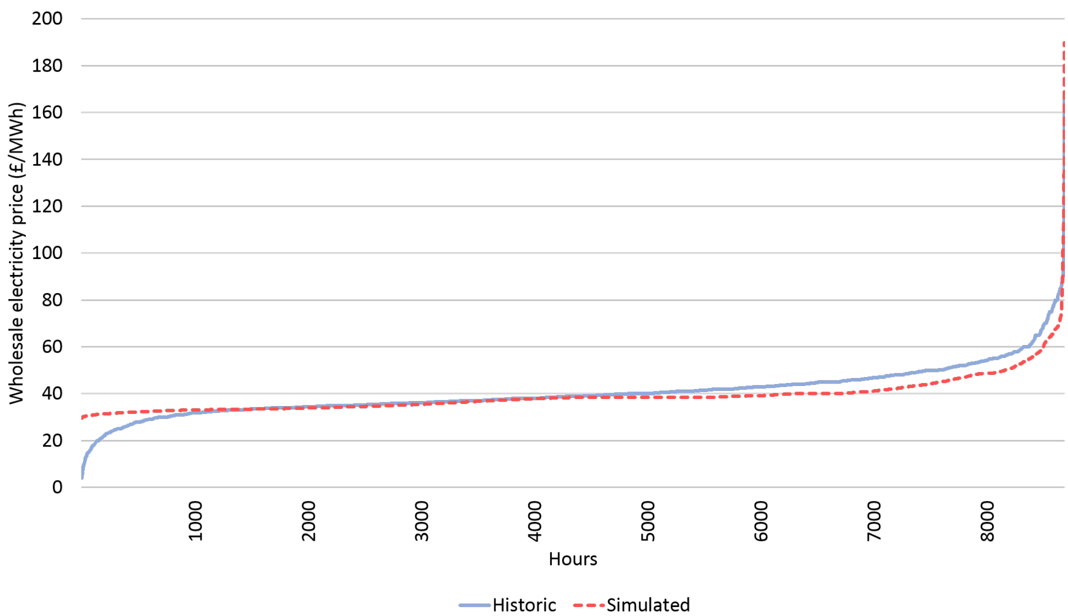


Figure 5.4: Price duration curve for historic and simulated price for 2015

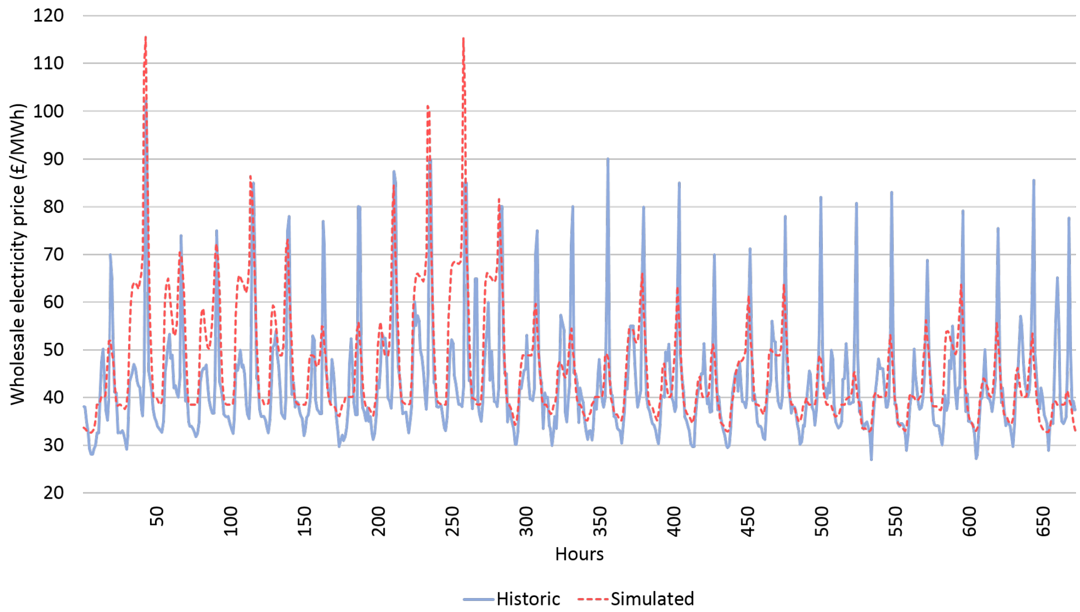


Figure 5.5: Comparison of historic and simulated wholesale electricity price for February 2015

price being 85.4 £/MWh.

5.3 Case study

Following a review of all scenarios in section 3.4, National Grid's Future Energy Scenarios (National Grid, 2016b) were chosen for the case study. There are four scenarios and in addition to the published reports and annexes, NG also provided Excel files specifying capacity predictions for each type of technology, specifying different types of storage technologies, wind technologies, natural gas technologies, and other generation types used in great detail, for all four scenarios. The scenarios also published the predictions for fuel prices, namely, coal, natural gas, and oil, with the exception of nuclear prices. Predictions for carbon and wholesale electricity prices in Britain were also included, however, predictions for future wholesale electricity prices for countries with which Great Britain has interconnectors to were not. Furthermore, the scenarios include predictions for the annual electricity and gas demand, and both are broken down into different components such as residential, commercial, industrial, in the case of electricity also electric vehicles and in the case of gas also transport and district heat. Average cold spell demand (ACS), peak demand, and energy (electricity and gas) annual demand predictions for all four FES are also included. For all four scenarios demand side response peak reduction predictions are also in the Excel sheet. Predictions for the capacity of each type energy storage technology are broken down for all four scenarios, providing capacities for pumped hydro storage and Lithium ion batteries. The predictions for the interconnector capacity levels by scenario and year are given, however, it is not specified which countries will be interconnected with Great Britain in the future and thus details based on capacity by country aren't disclosed. The available information helped with various components of the model. The predictions for natural gas and coal prices helped with establishing the position of the associated generating technologies on the merit order. Capacity and peak demand predictions for all four scenarios were also used as were the suggested demand side response reductions in demand to see what impact on peak wholesale electricity prices. Finally, based on the information regarding the growth of different energy storage technologies in Great Britain, FES data was used to define the characteristics for the aggregated storage device used for the dynamic programming component of the model.

5.4 National Grid's Future Energy Scenarios

NG's FES were designed to represent clear and holistic pathways to help navigate the British government through the varied energy terrain and aid in customer and stakeholder decision making. The scenarios are not intended to serve as forecasts, and rather they demonstrate a range of likely and convincing courses of actions for the future of British energy from the present day until 2040, as featured in the FES published in July 2016 (National Grid, 2016b). Every facet of the Future Energy Scenarios building process makes sure that the end product is valuable and robust in order for it to be able to serve as a reference tool for a variety of modelling operations and needs. To guarantee this standard is met, NG engages in comprehensive stakeholder consultation in addition to analysing the requirements of the grid in great detail, to enable NG to correctly pinpoint upcoming strategic investment requirements for the gas and electricity networks. Each report is split into a number of chapters, highlighting four energy growth scenarios - Gone Green (GG), Consumer Power (CP), Slow Progression (SP), and No Progression (NP). Each scenario represents a different direction of energy policy and development in GB. In the forefront of addressing ongoing concerns is the energy trilemma of security of supply, cost-efficiency, and sustainability, which serves as the base point for scenario development. The UK government has set a standard for electricity security of supply and developed the framework for this standard to be met by implementing the Electricity Market Reform (Department of Energy and Climate Change, 2013e). As the standard is set, NG scenarios alternate the two remaining variables, cost-efficiency and green design.

This work is based on the capacities published within the 2016 FES but since then the 2017 FES have been released. The numbers and ideas behind the scenarios do not vary to a great extent, however, the No Progress scenario is now labelled as the "Steady State" scenario and Gone Green has been renamed to "Two Degrees".

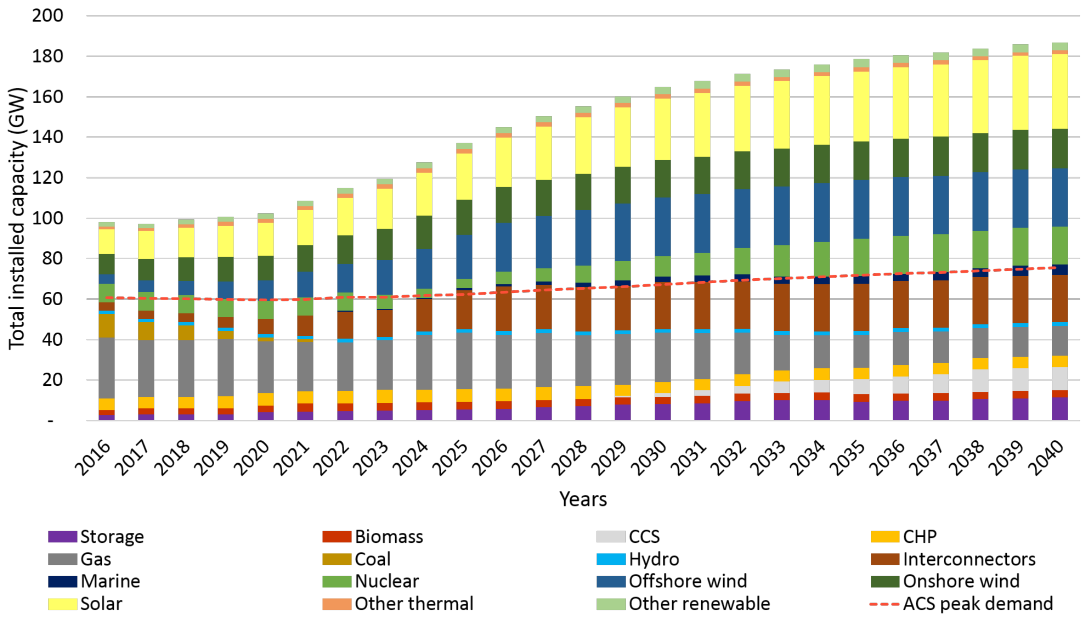


Figure 5.6: Gone Green installed capacity from 2016 to 2040

5.4.1 Gone Green

Gone Green scenario is the only one that reaches the intended emissions reduction targets. In GG, policy interventions are a driving force behind realising a renewable, low-carbon world. Funding is available to support innovation in green technologies such as renewable generation and low-carbon heating systems. Figure 5.6 contains the generation capacity predictions for the Gone Green scenario used for the calculations in this thesis's analyses.

Gone Green is the ideal world in which high levels of economic prosperity, green ambition, and keen societal engagement, coupled with forward thinking policy directives and cost-effective innovation allow for a successful manner of combating greenhouse gas emissions. The goal is to meet long-term environmental targets, maintain and increase high levels of prosperity, and push for a larger harmonisation on a Europe-wide level to make sure the 2050 carbon reduction target is met.

5.4.2 Consumer Power

For comparison purposes, the Consumer Power scenario, which is geared towards increasing the capacity margin, being more cost-efficient, and in general adding greater stability to the energy system, is also considered and ran with the model. Consumer Power is intended to exist in a market-driven world, with limited government intervention. High levels of prosperity allow for high investment and innovation. New technologies are prevalent and focus on the desires of consumers over reducing greenhouse gas emissions. The capacities corresponding to the scenario are displayed in Figure 5.7.

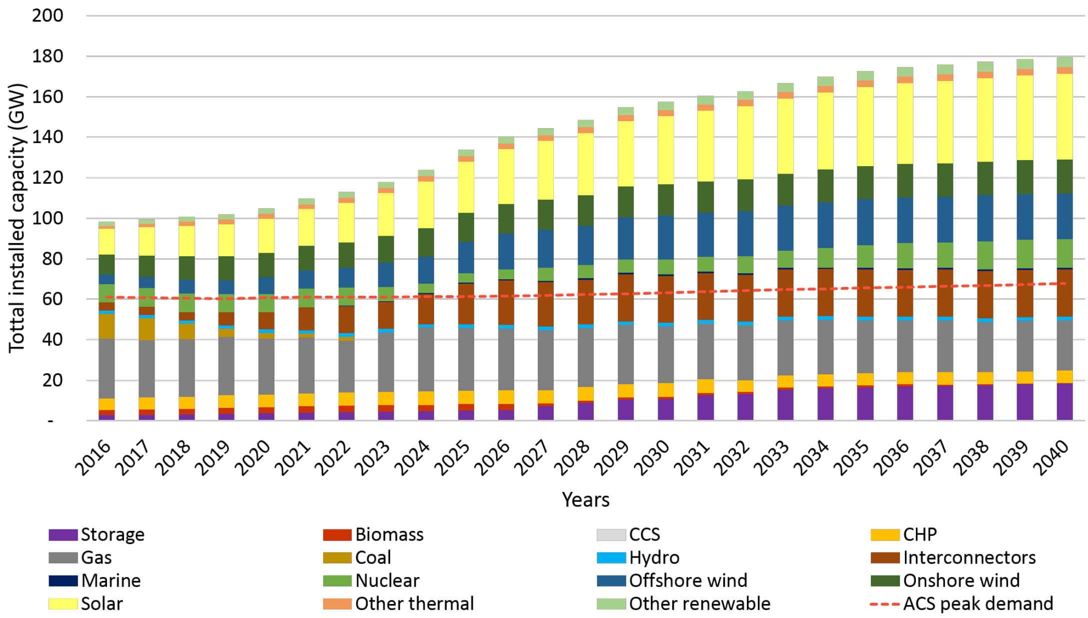


Figure 5.7: Consumer Power installed capacity from 2016 to 2040

5.4.3 Slow Progression

The Slow Progression world entails poorer economic conditions, which restrict society's wishes and abilities to transition to a low-carbon world with a green focus as fast as they would want. There is a limited variety of choices for both residential and business customers, however, novel technologies and policies are forming quickly. Due to a desire to decarbonise the economy and the ability to design generating technologies, which are environmentally friendly, there is overall progress, however, its pace is limited by high technology costs and overall low economic standards. Capacities predicted for the Slow Progression scenario are in Figure 5.8.

5.4.4 No Progression

No Progression demonstrates the development of energy in a world where business as usual activities are preferred. There is limited public engagement and interest in matters of sustainability. For such reasons the industry is allowed to no longer try to meet long-term targets but instead stresses the importance of meeting demand needs in the short term. With cost minimisation being a priority over the development of green technology, traditional sources of gas and electricity continue to dominate, with little innovation altering how energy is used. No Progression capacities used in FES since 2016 are in Figure 5.9.

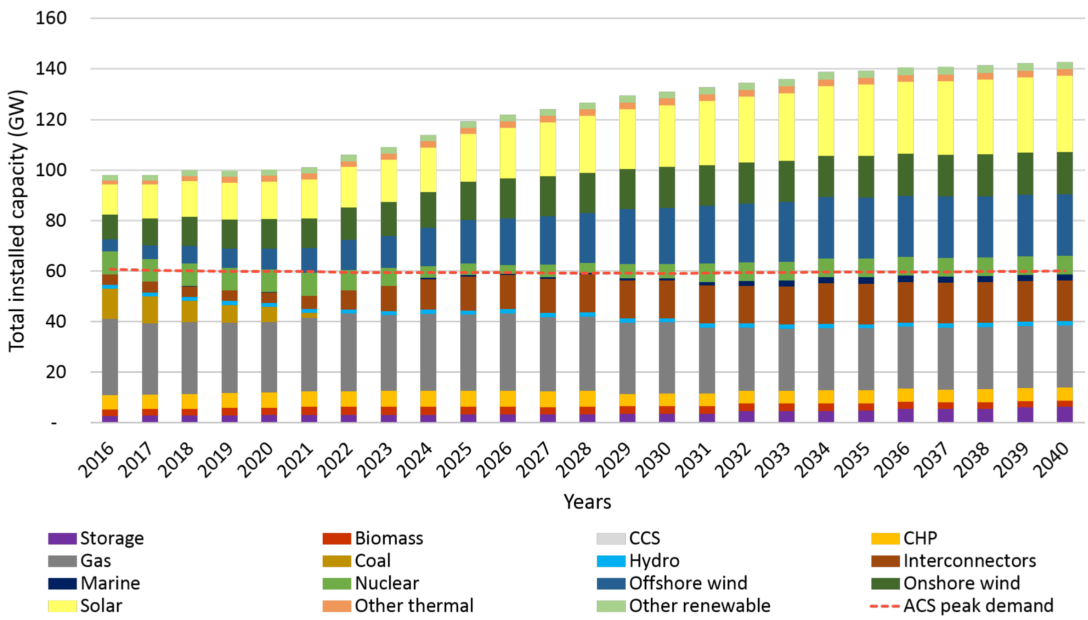


Figure 5.8: Slow Progression installed capacity from 2016 to 2040

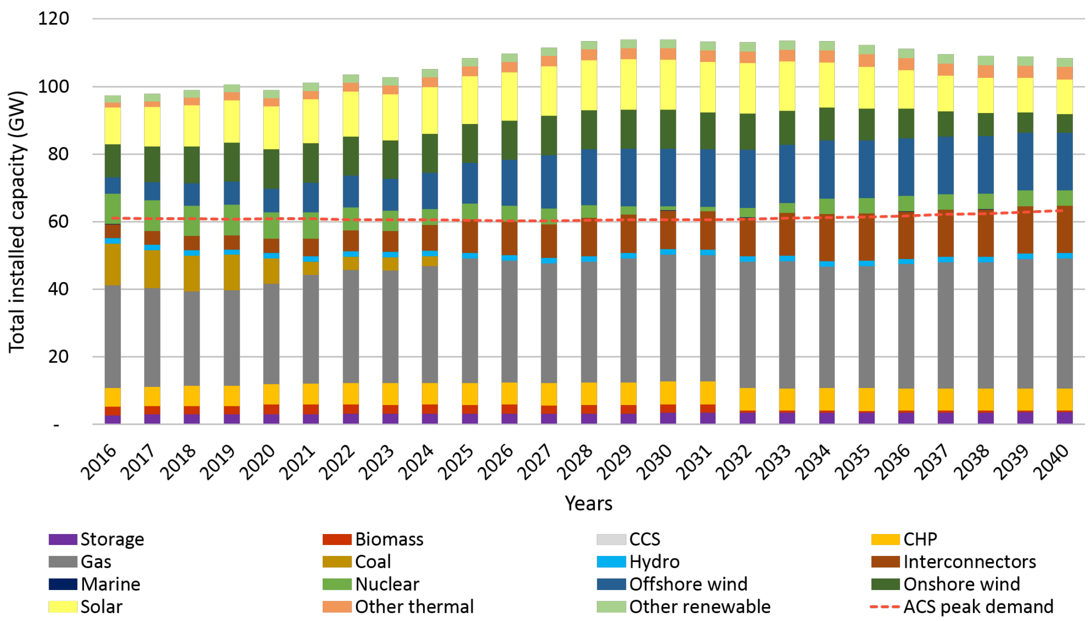


Figure 5.9: No Progression installed capacity from 2016 to 2040

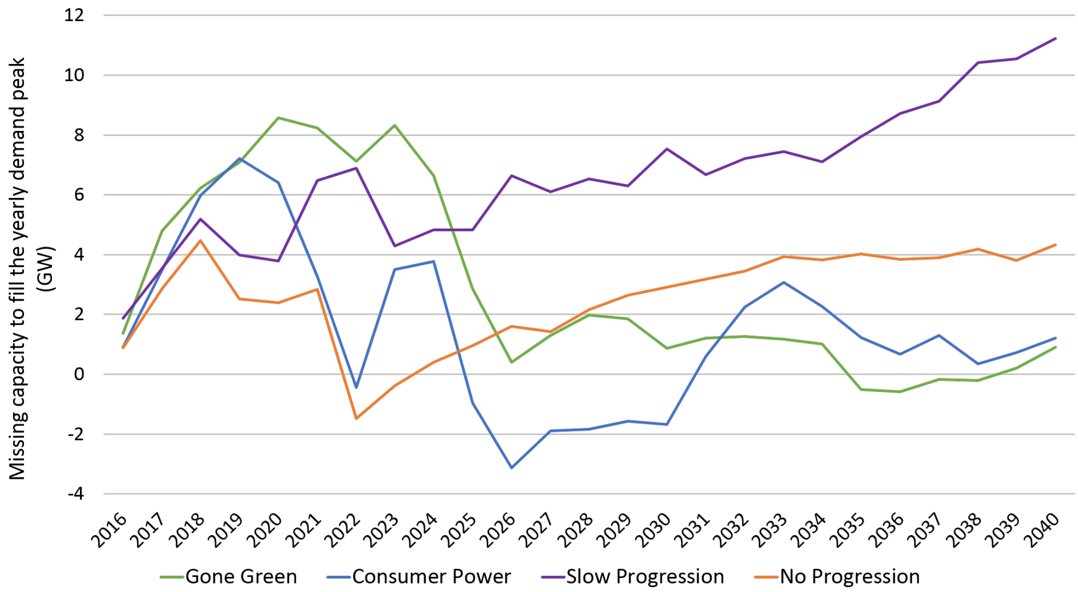


Figure 5.10: Capacity required to reach peak demand in each FES until 2040

5.4.5 Missing generation

Capacities of missing generation before the addition of OCGT capacity for each FES from 2016 and 2040 were calculated and are available in Figure 5.10. Renewable generation and interconnectors are already taken into account. The positive numbers show how much capacity is missing before the OCGT addition. In previous capacity market auctions diesel generators have won contracts (BEIS, 2016a). However, due to them being highly polluting, we assume that a more flexible, affordable, and not as polluting generator is used - OCGT, to help in times of expected generation capacity shortages (National Grid, 2015).

5.5 Interconnectors

The capacities projected by (House of Lords Economic Affairs Committee, 2017) and (Ofgem, 2017j) are not identical and they do not add up to the projections made by NG in FES. National Grid was contacted and the Interconnector Modelling Manager, Mr Andrew Dobbie, shared information about how NG determines the capacity that is included in FES. National Grid only provides the aggregated total interconnector capacity in FES rather than the details of individual projects as some of the information is commercially sensitive. Among the number of sources that list projects and future potential projects, some will be included in NG numbers, and others will not. For this reason interconnector capacities of each country were proportionally scaled up until the numbers proposed by NG in every individual FES are met.

In FES, interconnection plays a major role in sustaining Great Britain's security of supply, e.g. in Gone Green interconnector capacities increase up to 23 GW in 2040 (National Grid, 2016b).

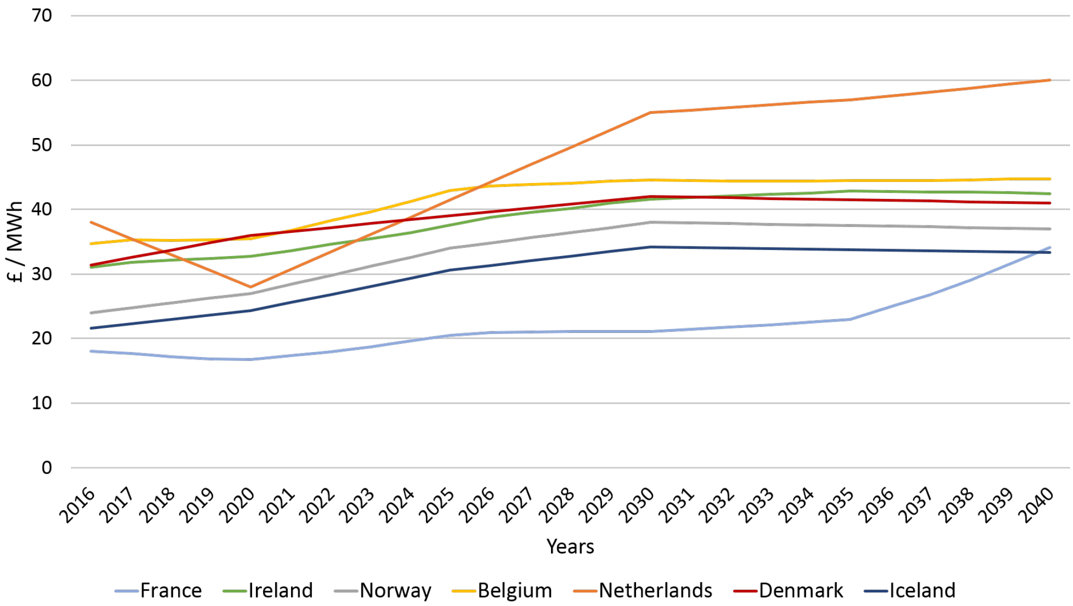


Figure 5.11: Average yearly future wholesale electricity prices of countries that have interconnections with Britain

For this reason, neglecting the interconnector capacities in the modelling approach could result in high levels of unmet demand especially during the hours of high demand and low renewable energy availability.

In order to acquire a consistent scenario for future developments on the energy markets, fuel price scenarios were assumed to be consistent with the ones obtained from NG FES and used in the main price model.

The predicted average future wholesale prices for each current and future connected country are displayed in Figure 5.11. The increase in Dutch electricity prices is linked with the Netherlands running out of domestic natural gas supply in 2025 and switching from becoming a net exporter to a net importer (Deloitte, 2015).

5.6 Demand side management

In order to achieve consistency, the same four scenarios from NG - Gone Green, Consumer Power, Slow Progression, and No Progression - were included with different amounts of peak reduction for each year between 2016 and 2040. National Grid separated residential DSM from industrial DSM and the same approach was employed here, however, a third approach was added in which the residential and industrial DSM were summed up.

The peak reduction used for every FES for every year can be seen in Figure 5.12. Peak reduction is displayed for domestic, industry, and "all".

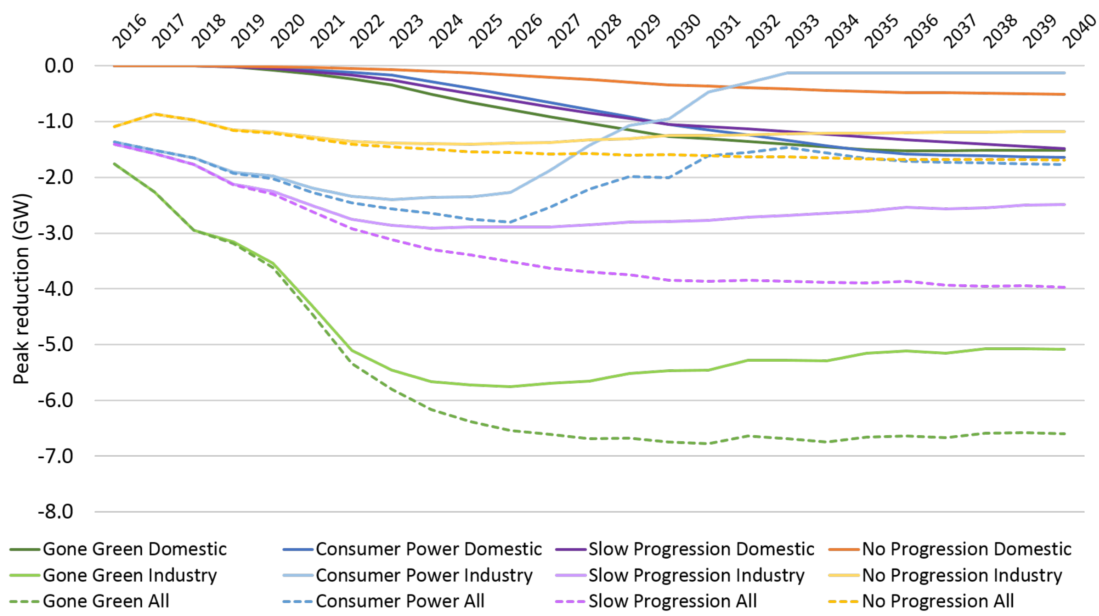


Figure 5.12: Peak reduction capacities from 2016 to 2040, for all FES, domestic, industry, and all

The impact of peak reduction on residual demand for January 2030, for the Gone Green FES, can be seen in Figure 5.13. The blue lines demonstrate the demand before the peak reduction suggested in this specific year for this specific scenario and the red dashes lines after peak reduction has been applied.

5.7 Energy storage

According to NG FES, storage could reach a combined capacity of almost 11.5 GW in the most optimistic Gone Green scenario by 2040 (National Grid, 2016b). Its potential crucial role can also be seen the NG FES predictions as without energy storage it would be impossible to meet the future growing demand (National Grid, 2016b). In this specific case study the storage volume of the aggregated storage operation unit is large and the resulting parameters for the installed capacity as well as the storage capacity (dashed lines) can be found in Figure 5.14.

In order to determine storage operation, information about the future installed capacity in storage, as well as the aggregated units' storage capacity and roundtrip efficiency is required. The parametrisation of the pumped hydro component can be derived from the fleet of existing hydro power plants in GB. The current day average characteristics of pumped storage hydro were obtained using data from the EnergyStorageExchange 2017 (United States Department of Energy, 2017).

Rated power as well as the capacity of the reservoir of the three biggest pumped hydro facilities in Great Britain can be obtained from the data shown in Table 5.2, also from (United States

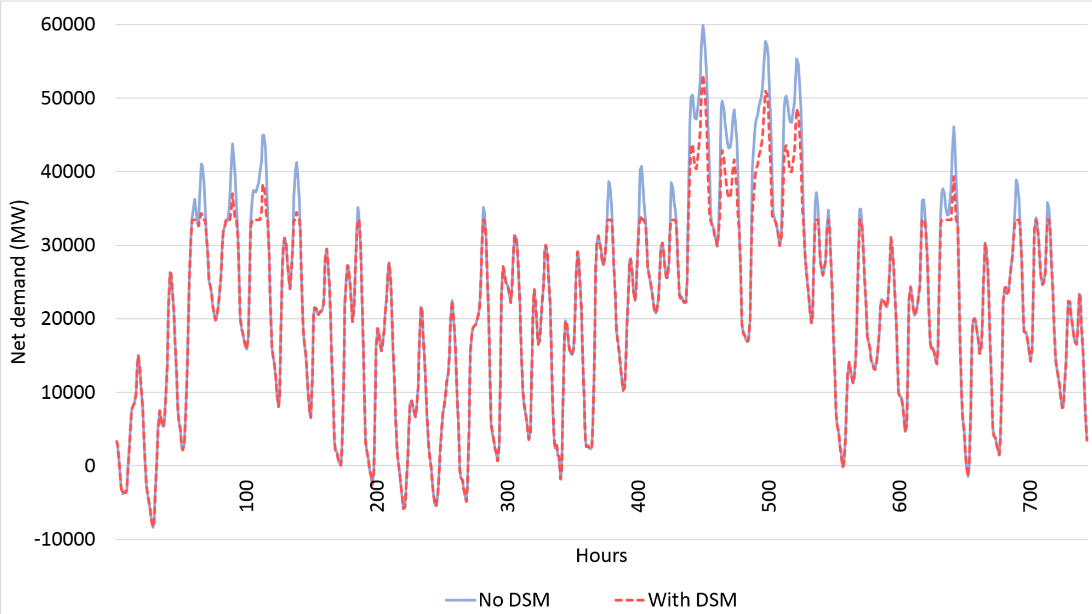


Figure 5.13: Residual demand for January 2030, Gone Green, before (blue dash) and after (red) peak demand was reduced

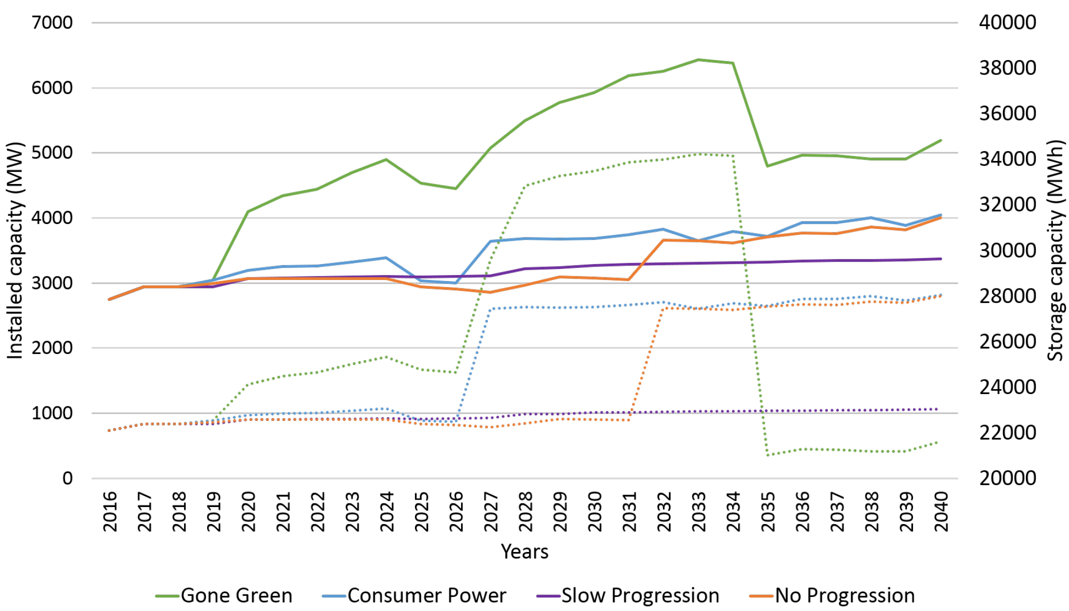


Figure 5.14: Parameters for the installed capacity (solid) and storage capacity (dashed)

Table 5.2: Rated power and capacity of the reservoir of the three biggest British pumped hydro facilities

Project name	Rated power (MW)	Reservoir size (MWh)
Dinorwig Power Station	1728	8640
Ffestiniog Power Station	360	2160
Cruachan Power Station	440	9680
Sum	2528	20480

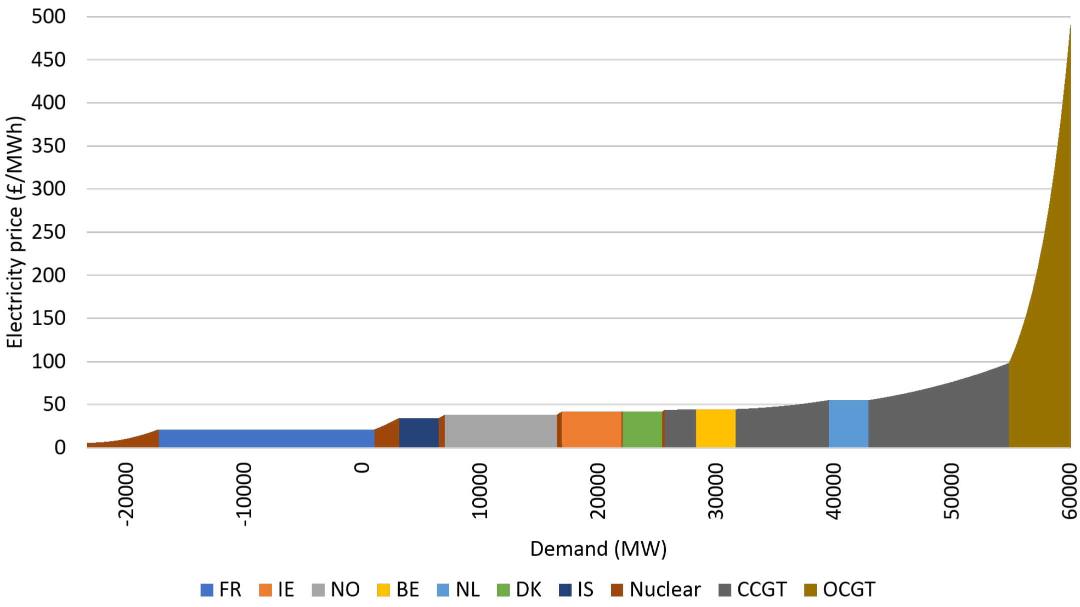


Figure 5.15: Example merit order for the year 2030 following the Gone Green scenario

Department of Energy, 2017). Based on these values, the storage-to-power ratio for future increase in installed pumped storage capacity is assumed to remain at 8 MWh storage per installed MW. The assumed average roundtrip efficiency of 70% as well as the parameters for Li-ion batteries are based on the technology review performed in Chapter 3.

The impact of storage inclusion on the merit order can be seen in Figure 5.15 for the Gone Green scenario in 2030, demonstrating the varying effect demand has on the resulting incremental price change.

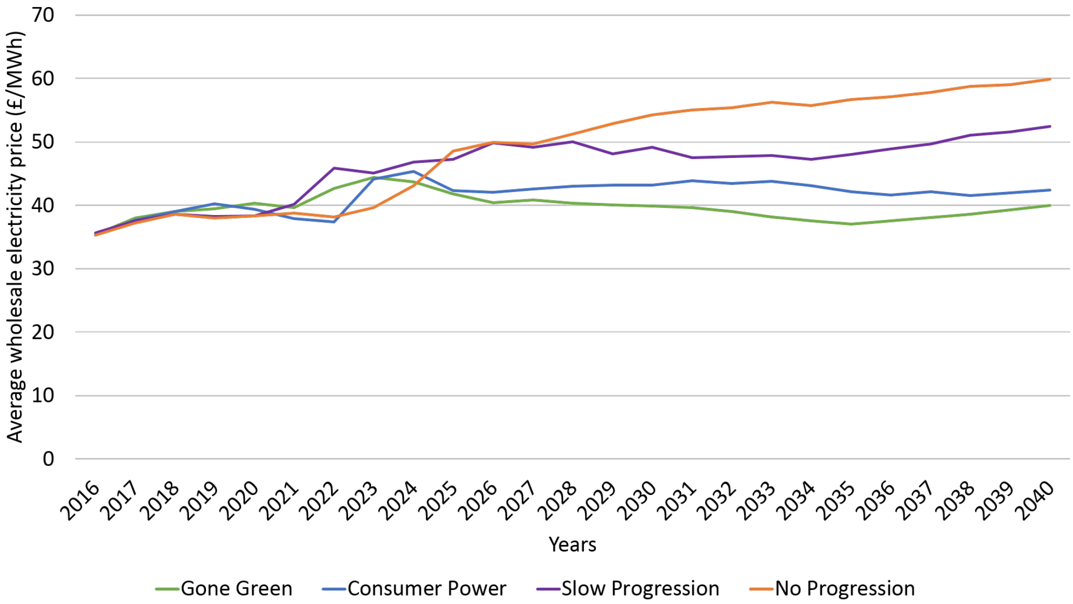


Figure 5.16: British wholesale electricity prices for all four FES between the year 2016 and 2040

5.8 Wholesale electricity prices

Renewable generation in Britain is the most invested in and relied on smart grid component. Significant changes to how electricity is produced in Britain have been witnessed due to renewable generation and more changes are to come. Wholesale electricity prices in the short term decrease with the inclusion of renewable generation, since they have no variable cost and thus once constructed their impact on the wholesale electricity market is decreasing prices. However, in the long term this causes a decrease in profitability of the existing thermal generation portfolio, which can result in a medium to long term lack of investment, which can in turn result in higher wholesale electricity prices and a capacity gap.

In Figure 5.16 the simulated wholesale electricity prices of the British market are displayed for every FES between the years 2016 and 2040. As the addition of renewable capacity with marginal cost of zero increases this leads to a decrease in average yearly wholesale electricity prices, which is best demonstrated by the difference in the price in 2040 between the Gone Green and No Progression scenarios, the scenarios with most and least renewables in the energy mix, respectively. The difference in prices between the Gone Green scenario and the remaining three can be seen in Figure 5.17.

During the time period between 2016 and 2040 the biggest continuous difference in electricity prices is between the No Progression and Gone Green scenarios. According to the performed simulations, an increase in renewable capacity does not lead to an increase in wholesale electricity prices over time under the overall capacity assumptions undertaken in the respective

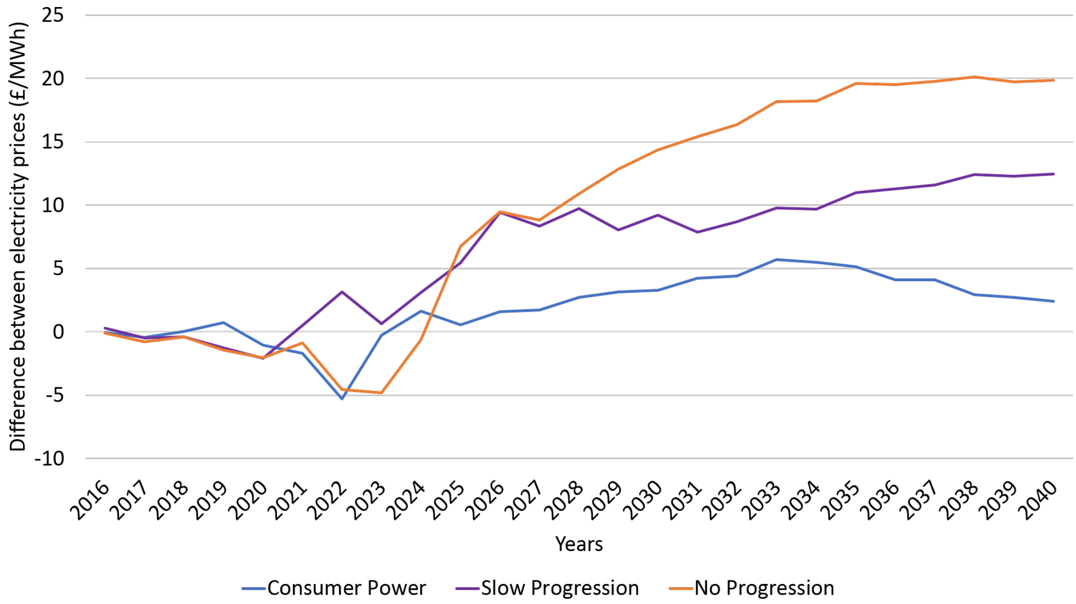


Figure 5.17: Differences in simulated wholesale prices between the Gone Green and the remaining three FES between 2016 and 2040

FES. In scenarios with a higher share of renewable generation, which can be assumed to have a higher capital cost, this cost is compensated for by a cheaper generation cost, which results in lower wholesale electricity prices. Initially, the wholesale electricity prices between the four scenarios are comparable as the two most significant impact factors, namely increasing interconnection capacities and raising installations of renewable generators are ramping up during that time. In the Gone Green and Consumer Power scenarios, wholesale electricity prices remain rather low or at least comparable to current wholesale electricity prices, which is due to a significant amount of wind and solar capacity that has been added, lowering the profits of thermal generation units. In the long term, generating companies respond to lower profits by closing down the thermal power plants, which then leads to sending electricity prices up. In the FES, however, this effect is not seen to a significant amount, as prices remain below the more conservative Slow Progression and No Progression scenario. Adding a bigger amount of renewables eventually leads to lower wholesale electricity prices as the four FES side by side show. This makes it possible to look at energy profiles in a short term and over a longer period, after the capacity has adjusted, which then pushes for additional research of what kind of capacity should be built. The result here would agree in favour of building additional renewable capacity when trying to achieve lower electricity prices as the difference between the price between Gone Green and No Progression is exceeding 20 £/MWh, and 10 £/MWh between Gone Green and Slow Progression from the mid 2030s on. The obtained results show a smaller difference between Gone Green and Consumer Power, which remains within a range of up to £6 per MWh for the entire simulation period and is close to zero or negative for the first ten years.

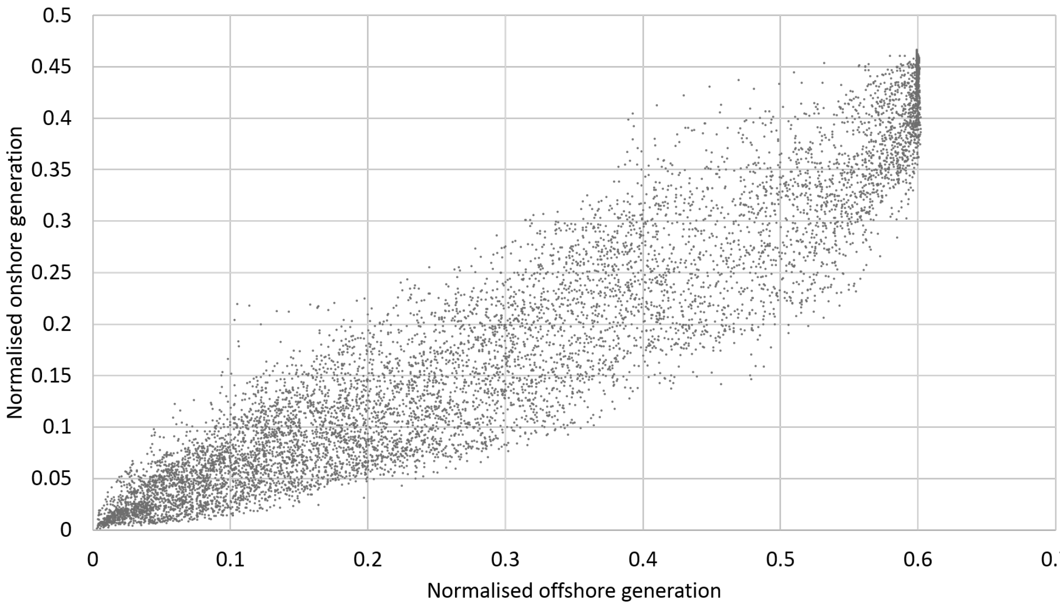


Figure 5.18: Normalised offshore and onshore wind generation for the year 2015 (ENTSO-E, 2015)

5.8.1 Base year impact on electricity prices

The year 2015 was chosen as the base year given that it is the most recent one, resulting in most comprehensive, accurate, and current data being used as a historical year to base the future predictions on. The year 2015, which is the reference year for demand and renewable generation profiles, was a weather year that resulted in a higher than average amount of wind generation (RenewableUK, 2017). The pattern of the normalised offshore and onshore wind generation for each hour of this year is shown in Figure 5.18. The figure shows the amount of generated electricity per unit of installed capacity. It is clearly visible, that there is a high correlation between times of high wind generation from land-based wind turbines in GB and the offshore wind parks of that year.

In order to achieve consistent calculations, which account for the correlation of weather-related effects on the electricity system, such as a change in electricity demand and change of intermittent generation, it is necessary to perform calculations based on a consistent historical year for all weather-related input data. On the other hand, weather data shows significant changes over past years in terms of temperature, wind speeds, sun insolation, etc. In future electricity systems, the market price will be especially dependent on the meteorological conditions for renewable energy generation, mainly wind and solar. To investigate the effect of the most recent base year - 2015 - on the results presented in this chapter, a sensitivity analysis with the historic data from the year 2012 to 2014 was performed. For this purpose, time series for these years have been obtained from (European Commission, 2017d), (National Grid, 2017e) and the simulation was performed for the period of 2016 to 2040 using the Gone Green scenario,

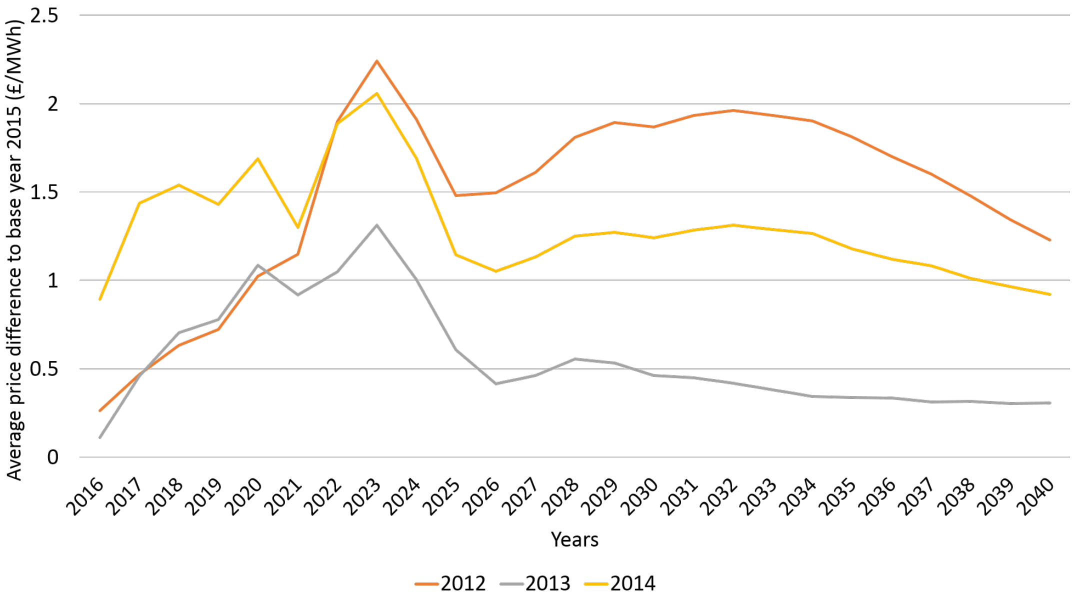


Figure 5.19: Average price difference to base year 2015 for FES Gone Green between the years 2016 and 2040

as renewable capacities reach the highest values and the price effect of weather variation can be assumed to have the highest impact. Furthermore, the Slow Progression scenario was investigated as the results show high electricity prices in the future years while there is still a considerable amount of renewable capacity installed, unlike in the No Progression FES.

Changing the base year to 2012, 2013, and 2014 proved to not have a significant impact on the overall wholesale electricity prices results. The impact of using different base years for the Gone Green and Slow Progression FES can be seen in Figure 5.19 and Figure 5.20, which display the average price difference to base year 2015.

As the year 2015 is characterised by very high wind generation in the EMHIRES dataset, all three simulated base years led to an increase in the average electricity prices. Among the three years, 2012 results in the highest electricity prices, while 2013 results in the lowest price increase. Initially the price increase in the Gone Green scenario is higher than in the Slow Progression scenario. In later years of the simulation, the price difference in Gone Green decreases from the peak in 2023 for all base years. This is caused by the high installed renewable capacities, which lead to a lower electricity price in general and also decrease the price effect of an additional unit of renewable generation on the price. This saturation effect is not observed in the Slow Progression scenario, where the price difference increases until the final simulation year 2040. Since the most recent historic values available from 2015 account for the electricity market characteristics, which shift towards a higher influence of renewable generation to the largest extent, the year 2015 was chosen as the base year for further analysis.

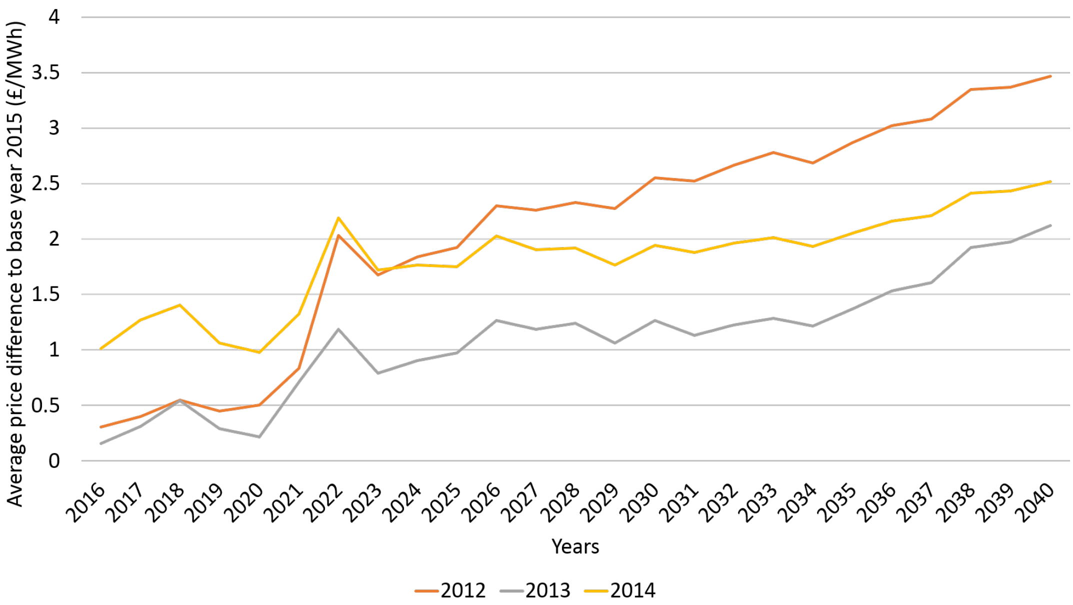


Figure 5.20: Average price difference to base year 2015 for FES Slow Progression between the years 2016 and 2040

The price for the year 2016 was generated as well in order to compare the simulated result to the 2016 price included by NG in their scenarios. The prices correspond mostly, except for in the No Progression FES, to the low price electricity case scenario, which is due to the high efficiency rates used for the thermal generation. More recent availability rates were used (Robinson, 2016) compared to (Dunbar, 2016), which also led to lower wholesale prices.

5.8.2 Interconnector flows

Another major model output is the flow over the interconnectors to the neighbouring countries. As a result of the modelling approach, import or export flows for every time step are included in the result. The results shown for the four scenarios represent the results under the inclusion of the storage model.

Different trends in the exchange of electric power can be seen from analysing Figure 5.21, 5.22, 5.23, and 5.24, each representing the annual interconnector flows for the Gone Green, Consumer Power, Slow Progression, and No Progression FES, respectively.

In Figure 5.21, the Gone Green FES, there is the biggest installed capacity of renewable generation among the four FES leading to the lowest wholesale electricity prices in later years. From 2016 until 2023, the Gone Green scenario is characterised by a supply shortage, as thermal generation capacities are decreasing while generation from renewable sources has not reached a level to compensate for it. As available capacities from interconnecting countries are increasing and average prices in these countries are below the British prices, the net interconnector flows are import-oriented for all connected countries, which agrees with the prognosis

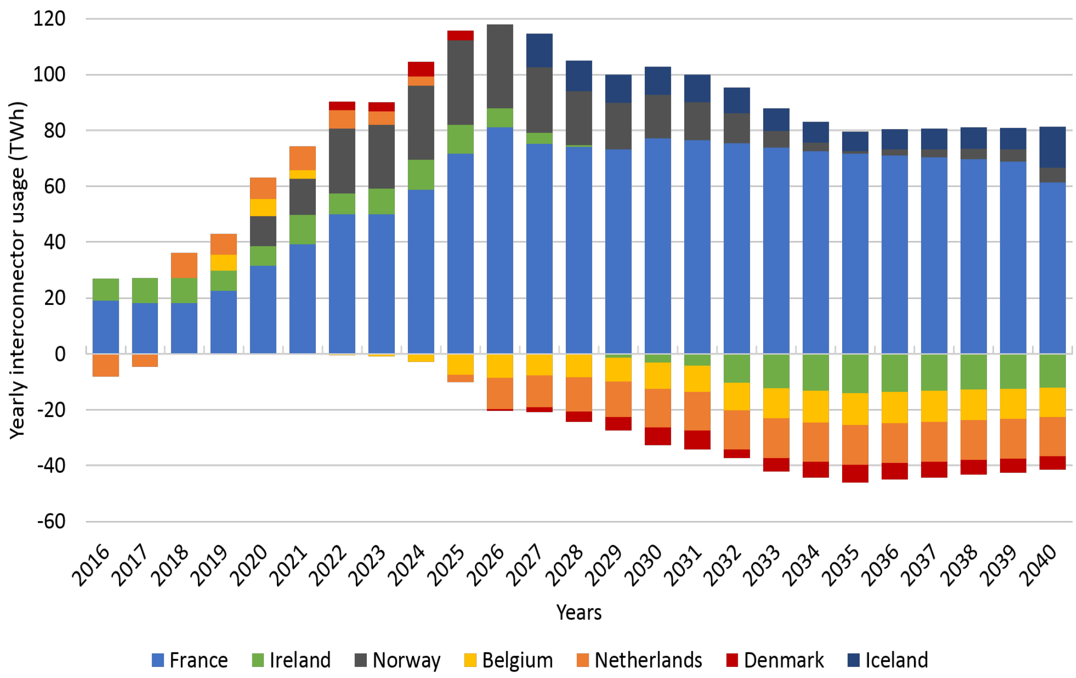


Figure 5.21: Interconnector flows between Britain and the countries it shares connections with for the Gone Green FES

from (Aurora Energy Research, 2016b). As French electricity prices remain consistently low during that period, import from France is increasing substantially to above 50 TWh. After the construction of the interconnector cable to Norway, import from Norway is becoming an increasingly significant factor, however net import is reduced significantly in the later years of the simulation. As the amount of installed capacity from renewables is steadily increasing, the difference of British electricity prices to the exchanging countries decreases and from 2023 on, over the entire year more electricity is exported to Belgium, the Netherlands, and in later years also Ireland and Denmark. Thus, the observed import dependency decreases towards the end of the simulation horizon.

Due to the lack of renewable generation built, which should provide lower wholesale electricity prices, Britain is forced to import more electricity from France in the Consumer Power scenario compared to the Gone Green one, as seen in Figure 5.22. As interconnection capacities are increasing comparably in Consumer Power, total import capacities above 100 TWh are reached in the mid 2020s. Analogous to the Gone Green scenario, a shift from net import to net export can be observed for Belgium, the Netherlands, and Ireland. In comparison to to Gone Green, both Norway and Iceland are a more relevant source of import.

In the Slow Progression scenario, displayed in Figure 5.23, a lower increase of interconnection capacities limits the possible exchange in both import and export. In this scenario, simulated electricity prices are increasing in the future, leading to France and Norway remaining countries

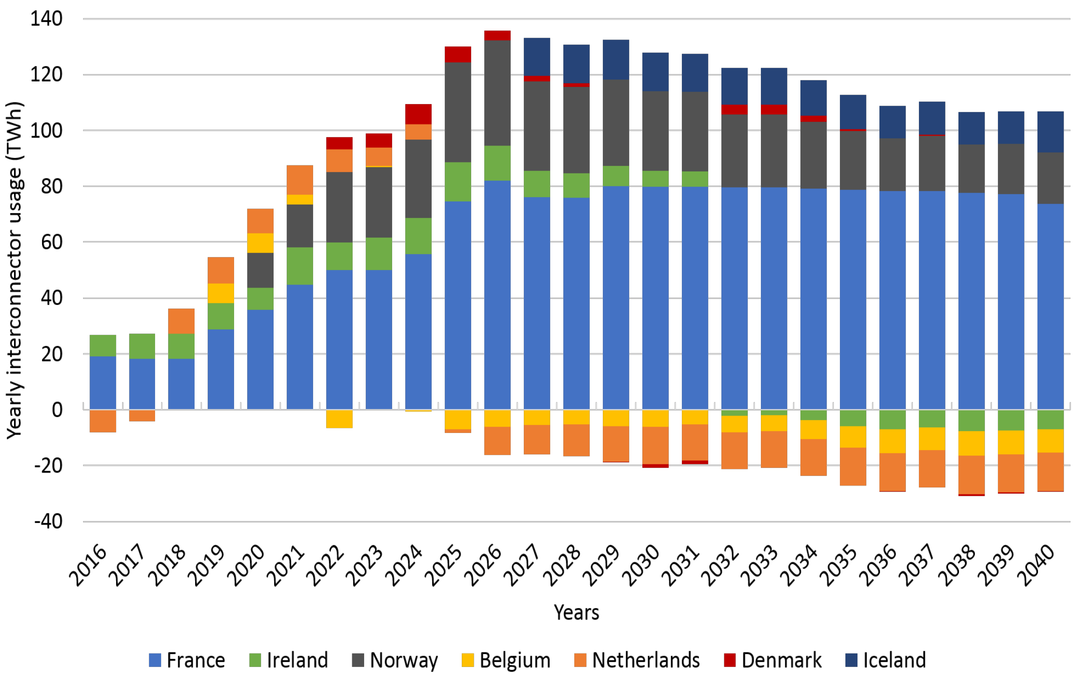


Figure 5.22: Interconnector flows between Britain and the countries it shares connections with for the Consumer Power FES

with a substantial amount of net import. As the spread of British electricity prices to the neighbours Netherlands, Belgium, and Ireland is still decreasing from 2023 on, net import from these countries is decreasing. Still, in the Slow Progression scenario Britain does not achieve a significant role as a net exporter to any of its interconnected countries but remains largely an electricity importer. As thermal generation costs go up in future years, the available capacities are helping in dampening the price effect on the electricity price.

Figure 5.24 displays the No Progression scenario in which the lack of renewable generation leads to steadily increasing prices which are well above the other scenarios simulated. The role of Britain as a net importing country is most dominant in this case, with a continuous import from the available interconnection capacities.

Since high prices are observed in the No Progression scenario, interconnection has a role to play when it comes to trying to dampen the prices. The observed net import values from 2025 on show a saturation effect, which leads to the assumption that more interconnection would be used for additional almost exclusive import.

Figure 5.25 represents the share of interconnector net flows as a percentage of the yearly electricity consumption for all four future energy scenarios from 2016 to 2040.

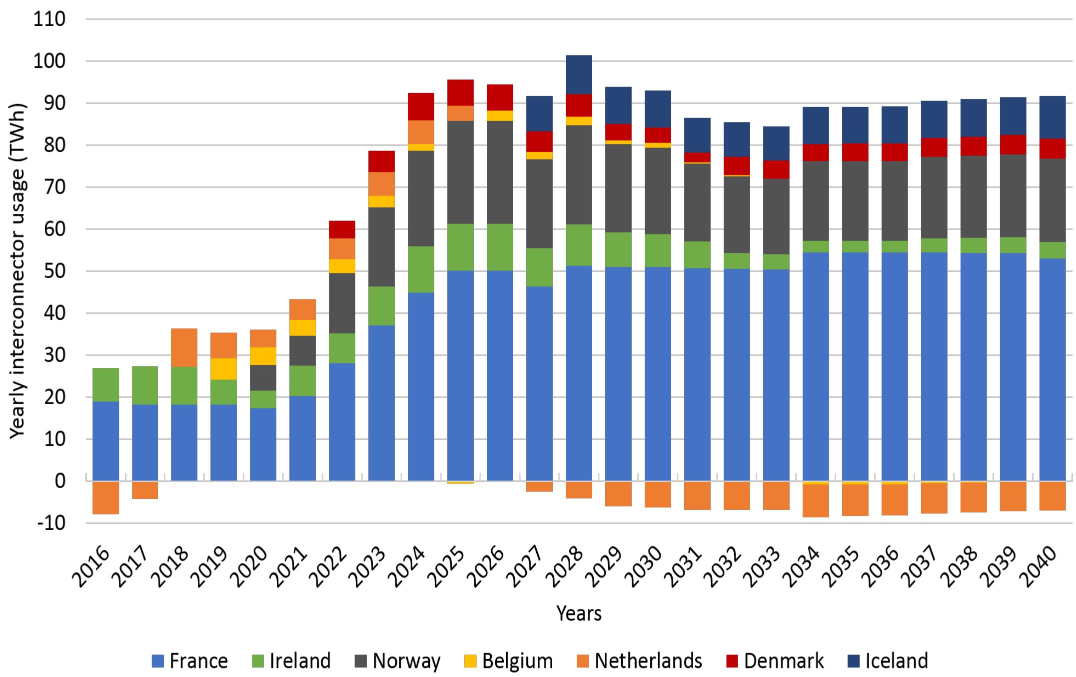


Figure 5.23: Interconnector flows between Britain and the countries it shares connections with for the Slow Progression FES

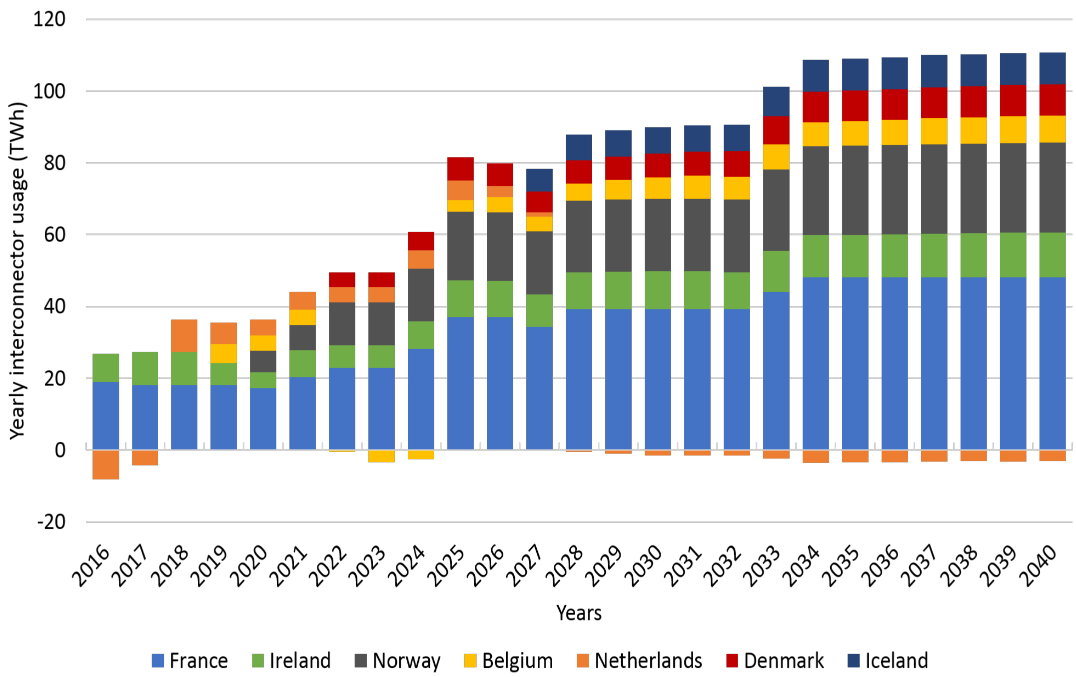


Figure 5.24: Interconnector flows between Britain and the countries it shares connections with for the No Progression FES

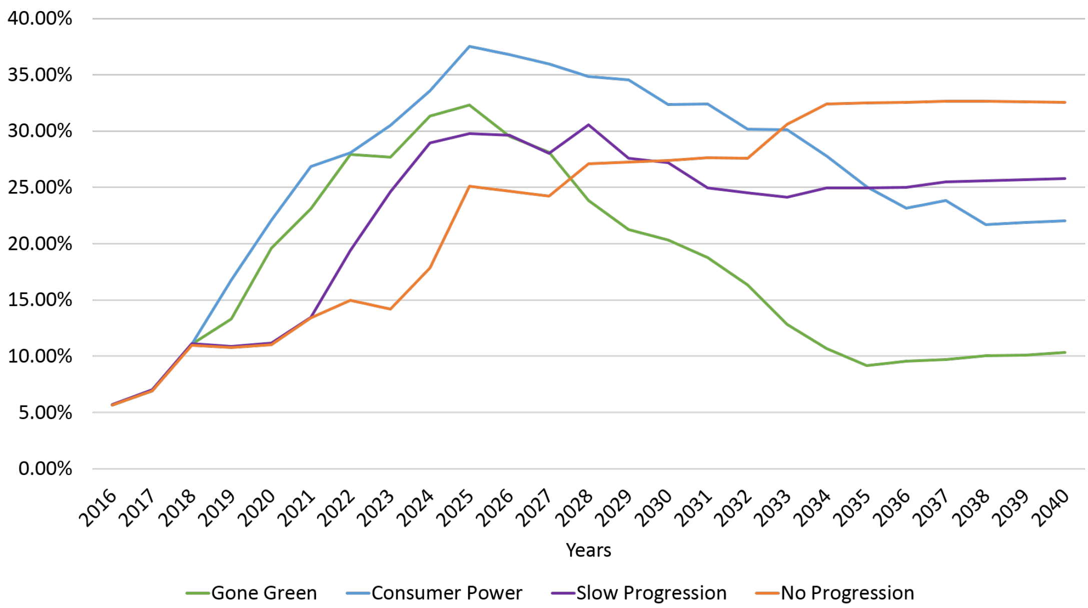


Figure 5.25: Share of interconnector net flows in the yearly electricity consumption from 2016 to 2040, for all FES

5.8.3 Conclusion

The average wholesale electricity price for Britain for 2016 was 42.63 £/MWh according to data from Ofgem, which is a little higher than National Grid predicts in the base case - 41.8 £/MWh (Ofgem, 2017i). After that in all four scenario an increase can be seen, however, for Gone Green and Consumer Power after the year 2023 prices start decreasing again. These two scenarios are also the two scenarios with the highest amount of renewable capacity. In 2040, the average wholesale electricity price is similar to current prices indicating that similarly to what was observed in Germany, in the beginning renewables can lead to a price increase, however as the capacity adjusts prices fall down to previous levels again as can be observed in our results in Figure 5.16 for Gone Green and Consumer Power. Thus, with proper support, renewables do not lead to higher electricity prices, at least not to prices much higher than they were before the introduction of renewable generation into the energy mix.

To confirm the reliability of results, the wholesale electricity prices that resulted from the runs based on the model developed for this thesis that had FES capacity, were plotted against the three scenarios from National Grid, high, base, and low electricity price (National Grid, 2016b). These three scenarios are included in the FES and contain the wholesale electricity price predictions according to the NG taking into account three different directions the wholesale electricity price might take in the future. Also included were the predictions for wholesale electricity prices from the Department for Business, Energy & Industrial Strategy (BEIS, 2017d), which included a low wholesale electricity price scenario and a high wholesale electricity price scenario. Aurora Energy Research (2016b) also predicts British wholesale electricity

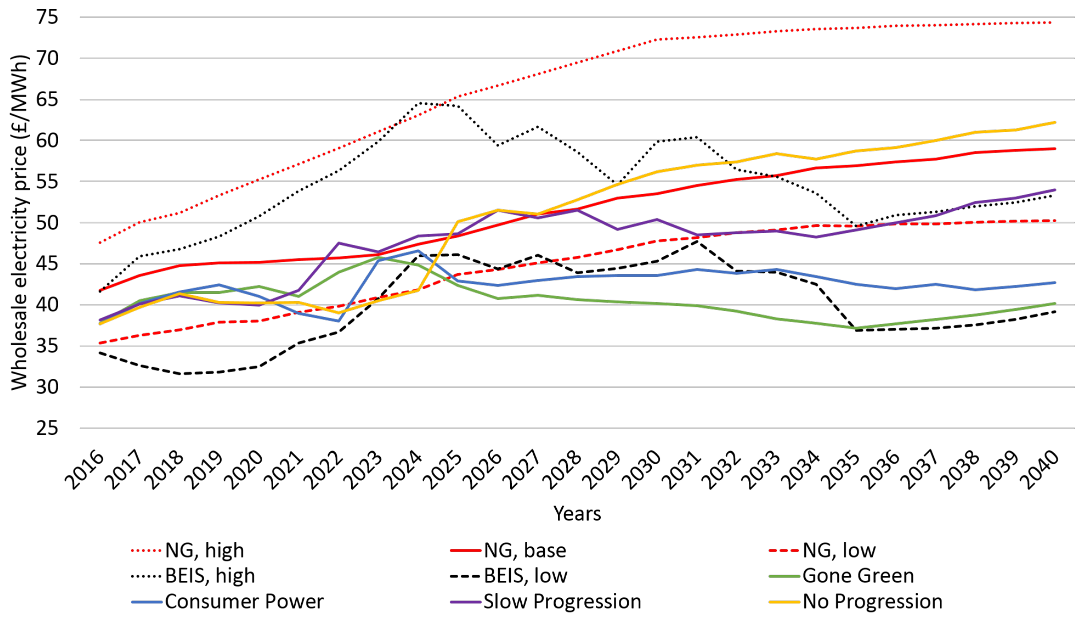


Figure 5.26: Comparison of simulated prices from FES with wholesale electricity price predictions from National Grid and BEIS

prices, however, (Aurora Energy Research, 2016b) does not provide the exact numbers for the predictions but merely plots them against its predictions for the electricity prices of the countries Britain has interconnectors with. From what can be observed in the figure included in the report the results from (Aurora Energy Research, 2016b) agree with the findings of this thesis. The wholesale electricity prices are plotted against each other for comparison in Figure 5.26.

The high scenario from National Grid results in by far the highest wholesale electricity prices and none of the other wholesale prices approach it. Even the base case from NG is higher than the rest of the generated prices that are supposed to represent other moderate price predictions and the prices higher than it are only from the No Progression FES but only by a margin and from the high BEIS scenario, which over time stops following the pattern of base case NG and No Progression and falls in value. Additionally, the National Grid wholesale prices are the only ones which witness a continuous increase in wholesale electricity prices. At the beginning, the low case from NG is similar to the Consumer Power simulated prices, however, towards the end, the NG low price is more comparable to the Slow Progression scenario. Comparatively, the simulated Gone Green prices come closest to the prices predicted by the Department for Business, Energy & Industrial Strategy in the low scenario. Slow Progression simulations fluctuate in between predictions from NG base and NG low.

Although Gone Green FES is the only FES that reaches the emissions target, from a business perspective Consumer Power is the scenario that also has high potential of being implemented in order to address any potential capacity gaps. The results of both simulated scenarios present findings that are comparable to simulated wholesale electricity prices from external predictions. The Gone Green scenario, without the exception of a predicted increase from mid 2020s to mid 2030s seen in the prices, is similar to the wholesale electricity prices predicted by BEIS's low price scenario. The other simulated scenario, Consumer Power, performed for this thesis resulted in wholesale prices that follow those of the National Grid low scenario.

Due to the difference in data, sources, and input of the merit order model of this thesis from those of National Grid and BEIS, the wholesale electricity prices patterns observed are not identical. However, the validity of the model is confirmed by the fact the results do not differ from one another to a significant extent, except in the most extreme case suggested by National Grid, the high case. All the results also fall between the expected limits of high and low wholesale electricity prices from 2035 onward.

5.9 Energy storage

Following the modelling approach described in section 4.7 the results presented in the following section were obtained. This section analyses the impact of energy storage on wholesale electricity prices in an energy system with various capacities of renewable energy generation, as included in NG FES. Demand side management is not included in this section of results.

5.9.1 Price difference

Figure 5.27 displays the difference which arises in wholesale electricity prices for all four FES until 2040 as a result of the addition of storage to the model and how that impacts the simulated prices for each year until 2040. This goes to show energy storage leads to a decrease in the average electricity price.

The impact of storage is rather small with the difference for Slow Progression ending up being the highest at the end of the analysed period, however, even that is only 1.5 £/MWh. Gone Green, which has the highest amount of storage, results in having the smallest difference between the prices, but slowly after 2034 a small increase in the difference can be seen as more and more storage and other low-carbon technologies are introduced into the British energy mix.

Wholesale electricity price volatility allows for more price arbitrage opportunities for storage. In No Progression and Slow Progression scenarios there is an increase in thermal generation over time, whereas renewable capacity does not increase. Volatility observed in resulting wholesale electricity prices makes it easier for storage to profit from price arbitrage. The opposite can be seen in the Gone Green scenario where prices decrease and peaks are sparse, resulting in less opportunities for storage to profit from price arbitrage.

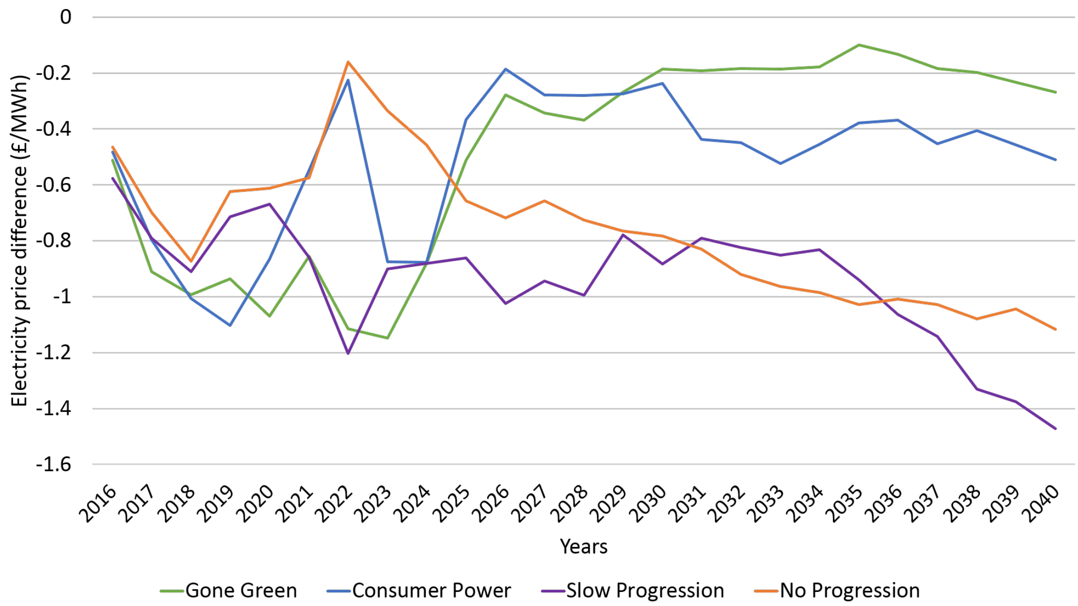


Figure 5.27: The difference in wholesale electricity prices for all four FES, before and after storage

5.9.2 Price duration curve

The calculated price duration curve in Figure 5.28 is for the year 2030 and displays the prices before and after storage. The FES displayed is Gone Green due to the minimal differences between the before and after storage price duration curves demonstrated runs performed for all other FES.

Comparing the before and after price duration curve it can be seen as one would predict that storage indeed reduces price peaks and reduces generation scarcity. In terms of public perception, a pattern with less price peaks is good, since it indicates a working market. The difference between the highest prices in the before and after storage scenarios is almost 250 £/MWh restating the important role storage has to play in keeping peak prices under control. However, there are downsides to a smaller amount of price peaks seen, mostly for the investors. The lack of price peaks reduces investment incentives for new generation units that could profit significantly from the occurrence of price peaks.

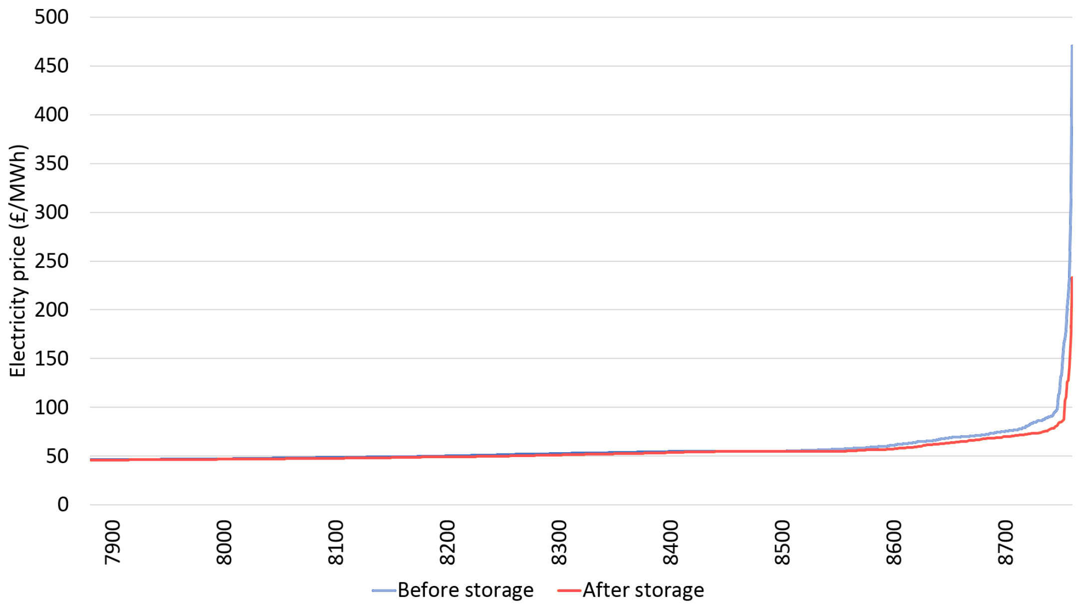


Figure 5.28: Price duration curve for Gone Green 2030, before and after storage

5.9.3 Interconnector flows after storage

An increase over years leading up to 2030 also demonstrates the role of interconnectors in reducing the price peaks in the market. Essentially, their role is similar to that of storage and a higher interconnected capacity also leads to less peaks in electricity prices.

Figures 5.29 to 5.32 display import and export interconnector flows for the four FES after storage application.

In Figure 5.29 it can be seen that storage operation leads to a demand increase in low-price hours to increase the state of charge for high-price times. This leads mainly to an increase in import from medium price interconnectors, such as Ireland and Norway, until the 2030s, as France is already used as a source of import most of the time. From 2027 on, the situational very high renewable generation leads to less import situations from France before the use of storage, thus import from France after the use of storage increases. In general, storage operation does lead to an increase in import, as all interconnector prices are well below OCGT peaking prices.

Just like in Figure 5.29, Figures 5.30 and 5.31 see more import from Norway and Ireland, following the pattern set in the Gone Green scenario. Import from France remains significant. However, some more export to the Netherlands, Belgium, and Denmark, more so in Figure 5.31 for the Slow Progression FES, can be observed from 2029 on as the prices in these countries slowly begin to go up.

In the No Progression scenario, visualised in Figure 5.32, smaller interconnector capacities lead to lower overall values. This is because a smaller renewable generation capacity results

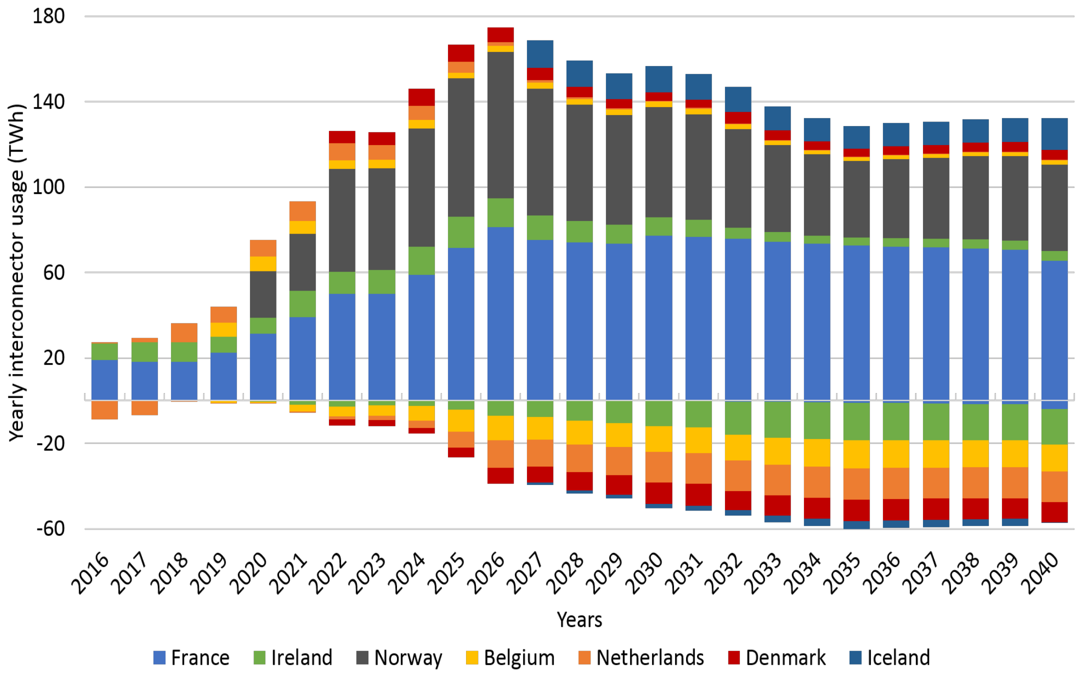


Figure 5.29: Interconnection imports and exports between 2016 and 2040 for the Gone Green FES after storage

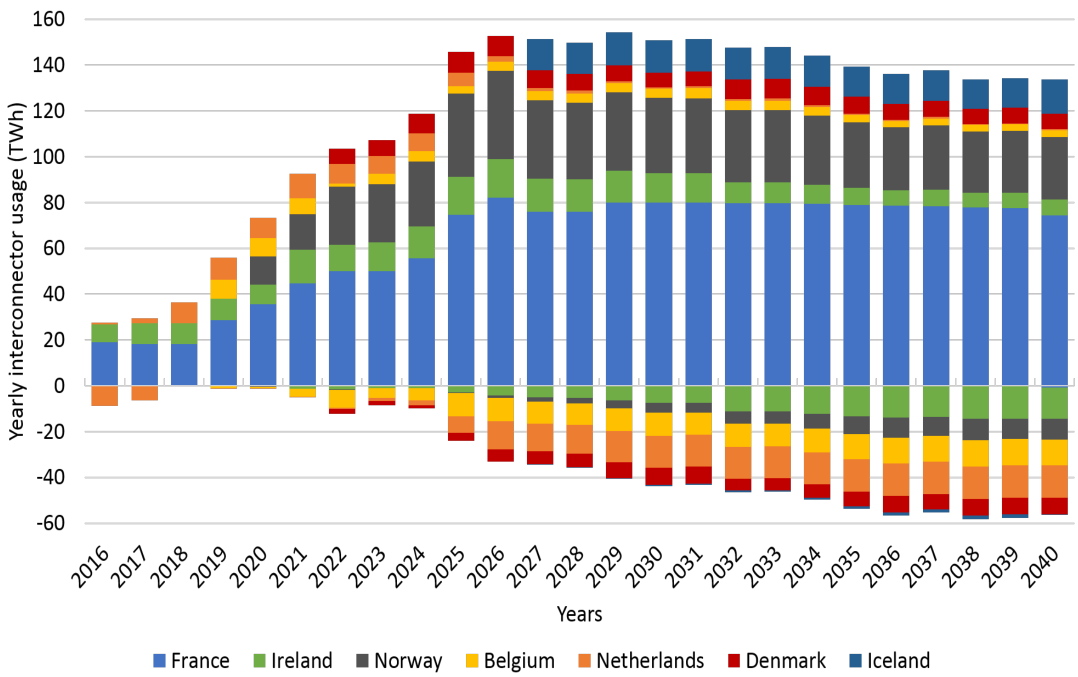


Figure 5.30: Interconnection imports and exports between 2016 and 2040 for the Consumer Power FES after storage

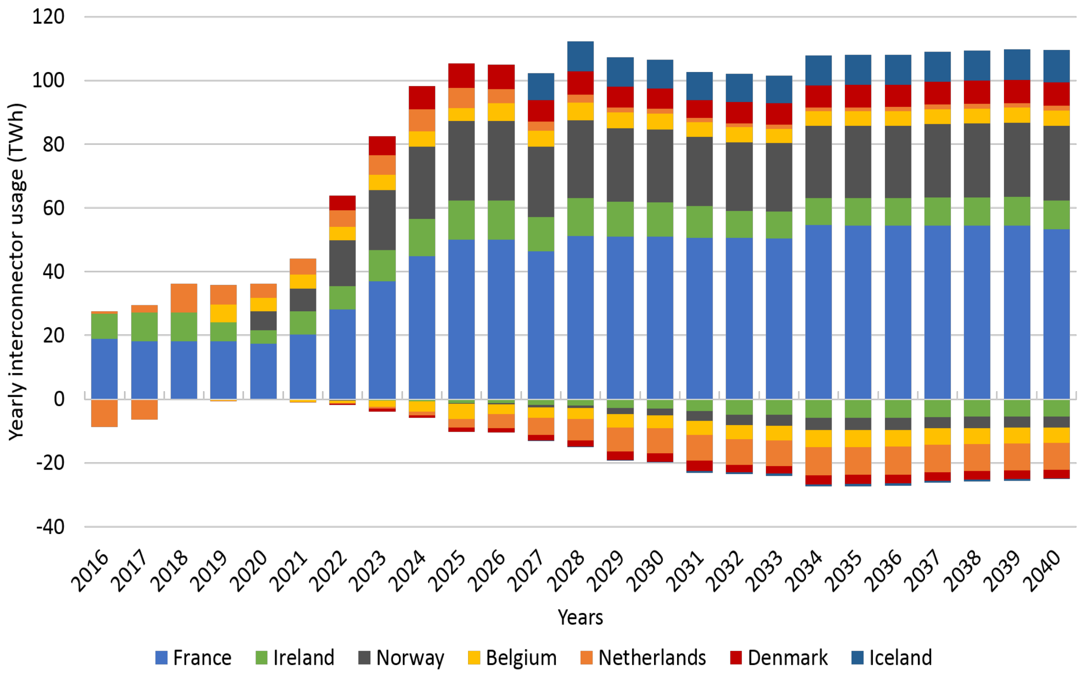


Figure 5.31: Interconnection imports and exports between 2016 and 2040 for the Slow Progression FES after storage

in a less frequent occurrence of low electricity prices, which can have a significant impact on interconnector utilisation. When prices are high, import from countries with lower prices is a priority and there is no change due to storage. Until 2027, Britain is increasing its import from the Netherlands, however, as it can be seen in Figure 5.11, Dutch prices begin to increase and in 2027 Britain increases its export to the Netherlands.

5.9.4 Storage revenue

Storage revenue displays a very volatile pattern in Figure 5.33 and starts at below £20 million for the entire portfolio in 2016, however, a quick increase is seen right afterwards. Until the year 2023 storage revenue in the Gone Green and Slow Progression scenarios is raising to above £65 million as both scenarios predict very high wholesale electricity prices, mainly due to a generational shortage, which can be seen in Figure 5.10, while revenues in the No Progression and Consumer Power scenarios fall below £10 million. Then, up to 2040, storage revenue in the No Progression and Slow Progression scenarios is still increasing. Slow Progression reaches almost £100 million because of the high capacity gap, lowered a bit due to more renewables compared to the No Progression FES. The general price increase combined with prices varying strongly between nuclear/interconnector prices and peak prices of OCGT leads to high revenue possibilities for the storage operator. Gone Green and Consumer Power both witness decreasing revenues from the 2020s until 2040. Increasing renewable generation in addition to increasing interconnector capacity leads to lower wholesale electricity prices. Additionally,

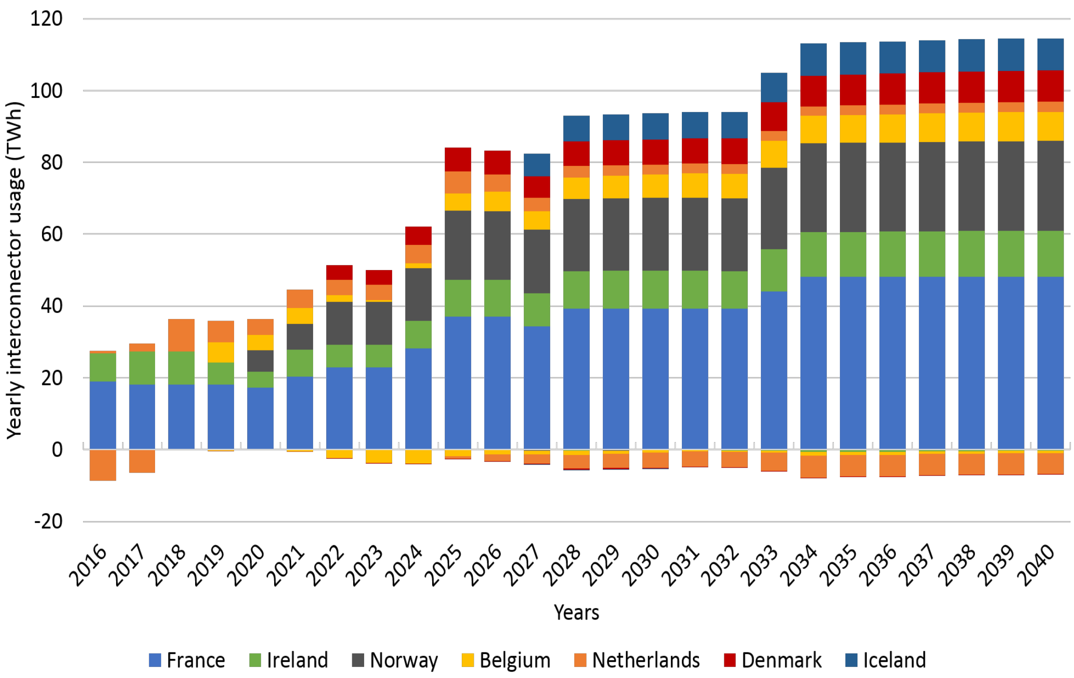


Figure 5.32: Interconnection imports and exports between 2016 and 2040 for the No Progression FES after storage

price peaks appear less often as they are dampened by wind generation, especially from the steadily producing offshore wind, in winter.

The amount of big price spreads decreases market opportunities for storage, which shows the overarching problem in current electricity markets: renewables decrease wholesale electricity prices and decrease the utilisation of peaker plants. As long as base load plants still exist, average prices as well as peak prices decrease, which also decreases incentives for storage investment. On the other hand, intermittent renewable generation requires storage in times of unavailability.

5.9.5 Conclusion

Energy storage, with the exception of pumped storage, is still an underrepresented technology in the British energy mix. However, according to NG predictions, especially in the Gone Green scenario, it is set to become a key element in assuring there is sufficient capacity in the system to prevent growing demand not being met in the future. The direction of storage can go from helping to prevent price peaks from appearing by ensuring low price volatility to serving itself and profiting from arbitrage when these peaks do appear in times when the sun is not shining and the wind is not blowing. Whichever the role, it is essential storage capacity predictions materialise as without it the security of supply could present itself as a significant issue given Britain's islanded position, as is the case when GB is unable to import power from

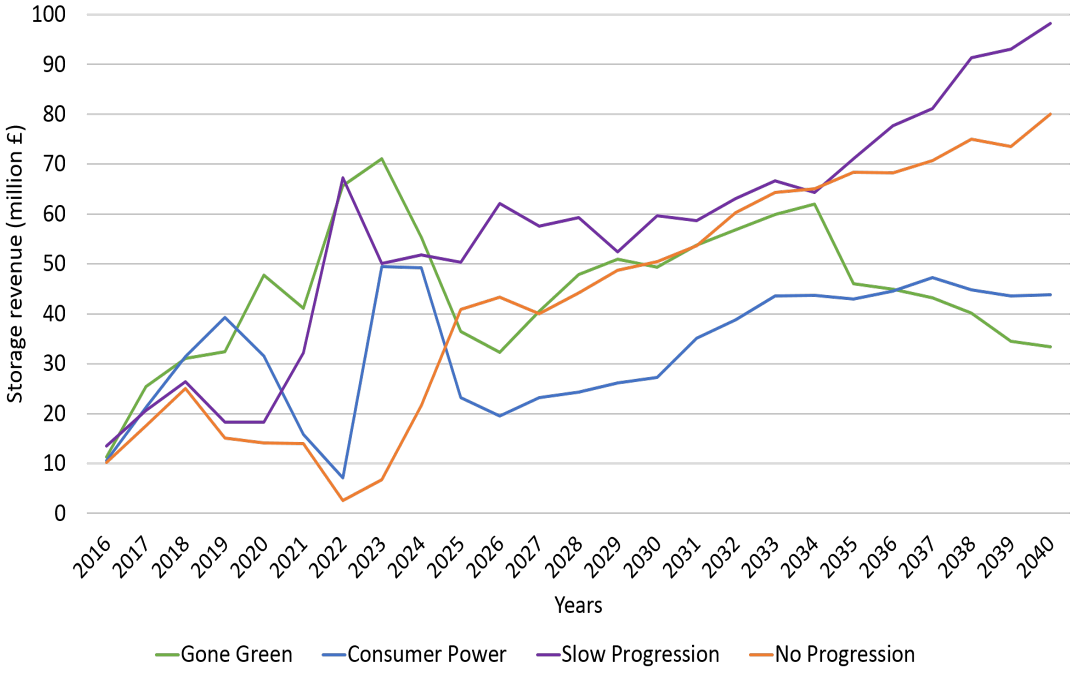


Figure 5.33: Storage revenue between the years 2016 and 2040

interconnected countries.

Bublitz *et al.* (2017) show in a case study of Germany that storage might not always be wanted in every energy system. Renewable generation drives the total wholesale electricity prices down and on average wholesale electricity prices in Germany have decreased by quite a lot. As renewable generation drives down the wholesale electricity prices, energy storage can cannibalise the profits of thermal plants so they earn less. This leaves the thermal generation with the option of either exiting the market and shutting down the power plants or increase their own flexibility by increasing their ramp rates at the expense of the plant's lifetime. Power plants are able to ramp up and down much faster but that can cause the material to degrade much faster. However, if the only chance the thermal generator has to continue making profits in the market is by increasing its flexibility it will do so, which in return decreases the opportunities for storage as the power plant is now able to operate for short periods and begin operation very quickly as is the traditional role of storage.

This section shows that energy storage does not have a significant impact on the reduction or increase of wholesale electricity prices as it can be witnessed in Figure 5.27. Similarly, the difference in interconnector flows before and after storage is not very big, and can be most clearly seen only in the Gone Green scenario in Figure 5.29. However, the price duration curve in Figure 5.28 proves that storage can have a significant impact on reducing peak prices. Thus, the real benefits of storage lie in securing additional capacity in times of peak demand and decreasing peak pricing.

The inclusion of energy storage can incur customer savings, which are displayed for the four scenarios in Figure 5.34. In an analogous manner to the interconnector savings seen in Figure 5.35, customer savings from storage are computed by calculating the prices with and without storage in each future energy scenario. The resulting consumer savings due to storage show a high correlation to the revenue of the storage operator in the same scenario and year as seen in Figure 5.33, as savings occur mostly when high electricity prices can be significantly reduced by storage operation, also benefiting the revenue of storage. This effect is seen to its largest extent until 2022, as generation capacity is very scarce and interconnector capacities have not reached their peak. Afterwards, a significant drop in consumer savings can be observed, especially in Gone Green and Consumer Power, which do not rely on thermal generation as the major contributor to electricity generation. This shows a paradox of the electricity market, which sees declining prices with the addition of renewable generation without variable cost, yet on the other hand needs storage as a balancing element due to the volatile nature of wind and solar energy. In NP and SP, no significant reduction of consumer savings from storage is observed, with storage continuing to be the main source for price reductions in high demand hours by providing generation capacities that would otherwise be supplied by expensive peaking generation.

The most comprehensive review of the value of storage in a low-carbon system is perhaps (Strbac *et al.*, 2012), where some of the problems the study aims to assess are the cost and performance targets for grid-scale energy storage applications, sources of value of storage, i.e. savings in capital expenditure in all sectors including generation, transmission and distribution infrastructure, the impact of competing options such as DSM, renewables, and interconnection, and changes in value of storage across key decarbonisation pathways. The study presents a whole systems approach to valuing the contribution of grid-scale electricity storage in future low-carbon energy systems, which minimises investment and operation cost to future GB systems. The study provides very comprehensive results that research different areas and among them it is shown that the value of storage is the highest in pathways with a large share of renewables, where storage can deliver significant operational savings through reducing renewable generation curtailment. In an example of distributed storage of 10 GW installed capacity it is shown that in a high renewables scenario in 2050, application of energy storage technologies could potentially generate total system savings of £10 billion/year. Zafirakis *et al.* (2013) carry out a valuation of policy options to promote wind-based energy storage systems by employing a cost-benefit model that among other things takes into account the initial investment subsidies and FiTs. PHES and CAES are examined covering peak demand with the results proving that such systems can prove cost-effective with the correct application of FiTs. Kaldellis *et al.* (2009) maximise the contribution of the PV generator and minimises the life-cycle electricity generation cost of the remote island networks investigated, while special emphasis is given in order to select the most cost-efficient energy storage configuration available. Arce *et al.* (2011) provide the first overview of the Spanish thermal energy storage potential for energy savings

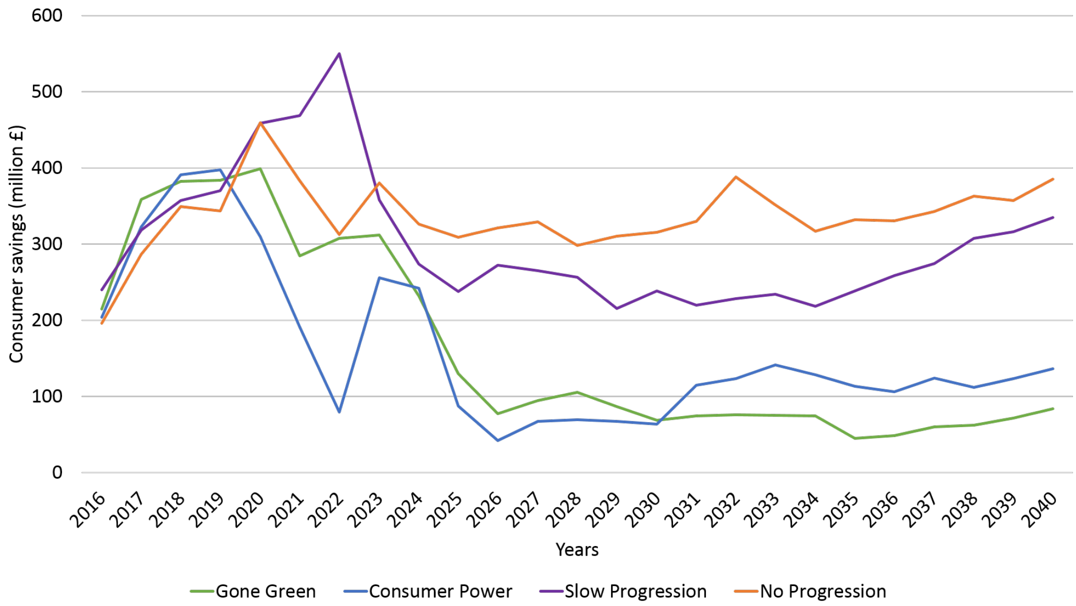


Figure 5.34: Consumer savings incuring from energy storage from 2016 to 2040, for every FES

and climate change mitigation while also providing an European overview. Load reductions, energy savings, and CO_2 emissions reductions are tackled for residential and non-housing buildings and the industrial sector.

By excluding the available interconnector capacities in each scenario, the theoretical consumer benefit of interconnectors can be determined. The results of the yearly consumer savings due to the interconnectors are shown in Figure 5.35. It can be seen that the existence and usage of the interconnectors leads to significant consumer savings as prices in GB are largely reduced due to the characteristics of the GB market with large amounts of import and an even increasing import predicted for the future. In the future years, the projected savings between the four FES develop in a similar manner to the predicted prices in the scenarios, as higher general prices lead to higher reduction potential for exchange. Even though the projected interconnection capacities are lower in the NP and SP scenarios, these lower capacities are being outweighed by the increased prices. With regard to the GG scenario, a reversion of the overall trend of increasing consumer savings over time is being observed from the 2020s on, as the lowering prices due to the strong increase in installed RES capacities dampen the price increase. When interpreting these results, several limitations of these results have to be kept in mind. First, the interconnection capacities are taken out of the individual scenarios, resulting in additional missing capacity which is then being adjusted as described in sections 4.4 and 5.4.5. This leads to the entire amount of the missing capacity being replaced by a very expensive technology, OCGT, which is mostly used for peak generation in today's energy systems. Thus, the resulting wholesale electricity prices are much higher than they would be when assuming a wider

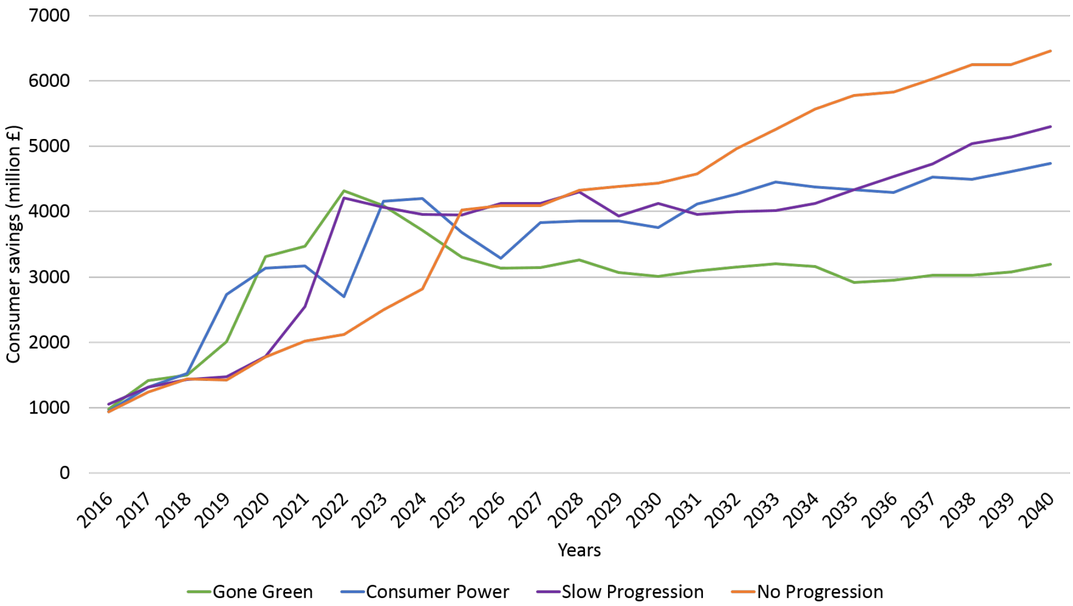


Figure 5.35: Consumer savings incuring from interconnection from 2016 to 2040, for every FES

technology choice to fill the capacity gap. Second, the individual FES have been developed with a pre-specified amount of interconnector capacity available in each respective year, thus the generation system provided by the scenarios is designed to operate efficiently with these capacities. By removing the entity of interconnection lines, the initial idea of each scenario cannot be uphold, thus the remaining system is a very inefficient system. Both effects together lead to a great amount of overestimation of the consumer savings due to interconnection lines, but the results still show the high importance of these interconnectors in for these future scenarios and the high economical cost that come with neglecting their absence.

Although comparison of the interconnection savings from this thesis is difficult due to the reasons stated above various work has been performed on the topic of interconnector economics. The cost benefits of interconnection are discussed in (De Nooij, 2011), where the NorNed interconnection between Norway and the Netherlands and the East-West interconnector are evaluated. The results show that connecting two grids may reduce the need for generation capacity if peak demands are not closely correlated. The economic significance of Basslink in the Australian National Electricity Market is discussed in (Malla *et al.*, 2011), where three different market development scenarios are studied. The results show that the net present value of market benefits attributable to Basslink remains positive in all market development scenarios, which signifies that Basslink is economically worthwhile. In all market development scenarios Basslink is able to deliver significant savings in operating cost and in capital cost benefits. Malaguzzi Valeri (2009) studies the effects of additional interconnection between Ireland and Great Britain using a static optimal dispatch model, based on historic

2005 fuel prices and generation plant mix. The analysis also determines how sensitive the results are to changes in the cost of carbon. The general pattern shows that Ireland gains and Great Britain loses with interconnection. The sum of Irish and British social welfare increases with interconnection, although at a decreasing rate. In (Konstantelos *et al.*, 2017) the costs and benefits of integrated projects are quantified and it is investigated to which extent the cost-benefit sharing mechanism between participating countries can impede or encourage the development of integrated projects. Three concrete interconnection case studies in the North Sea area are analysed in detail using a national-level power system model. The results show that in all three case studies, the integrated network is more beneficial than its conventional counterpart and the benefits of all three projects are shown to be largely inter-independent.

5.10 Demand side management

For the results presented in the following sections, peak reduction was included in the modelling approach. The effect of DSM on peak electricity prices as well as revenue of energy storage operators is investigated using multiple scenarios of available DSM potentials based on the peak reduction numbers provided by National Grid (National Grid, 2016b). The results illustrate the wholesale electricity prices between 2016 and 2040 resulting from demand before peak reduction and the wholesale electricity prices that arise as a result of reducing peak demand following the initial results. The results for each FES are evaluated based on the domestic, industrial, and all scenario. The domestic scenario only applies peak reduction for the specific FES in that year for the residential DSM, which in the case of NG is only due to time-of-use tariffs and smart appliances. The industry scenario only applies the peak reduction for the specific FES in that year for the industrial and commercial DSM, and the "all" scenario combines the domestic and industry peak reductions to see what would the resulting wholesale price be if both are applied.

Figure 5.36 shows the price duration curves for peak reductions for the year 2030 for the Gone Green and Consumer Power FES. The four categories compared are All, Industry, Domestic, and None, which shows the peak prices when there is no DSM. As expected most of the peak prices occur when no peak reduction is applied with the Gone Green None curve reaching top prices at more than 230 £/MWh. Peak reduction of Gone Green Domestic can also be pointed out on the graph individually, as the drop is significant with the peak prices now rising above 170 £/MWh. The drop for Gone Green Industry and All peak reduction is even more significant of almost £77 for Industry and as low as £72 for All. This agrees with (Albadi and El-Saadany, 2008) as a small change in DSM can have very big impact on the electricity price structure. The higher the application of DSM the smaller the observed price peaks as seen in Figure 5.36 as well. A similar pattern as in Gone Green can be observed in the Consumer Power curve, except that the peak prices differ. For None the peak price is £177, however, the All price is £123.5,

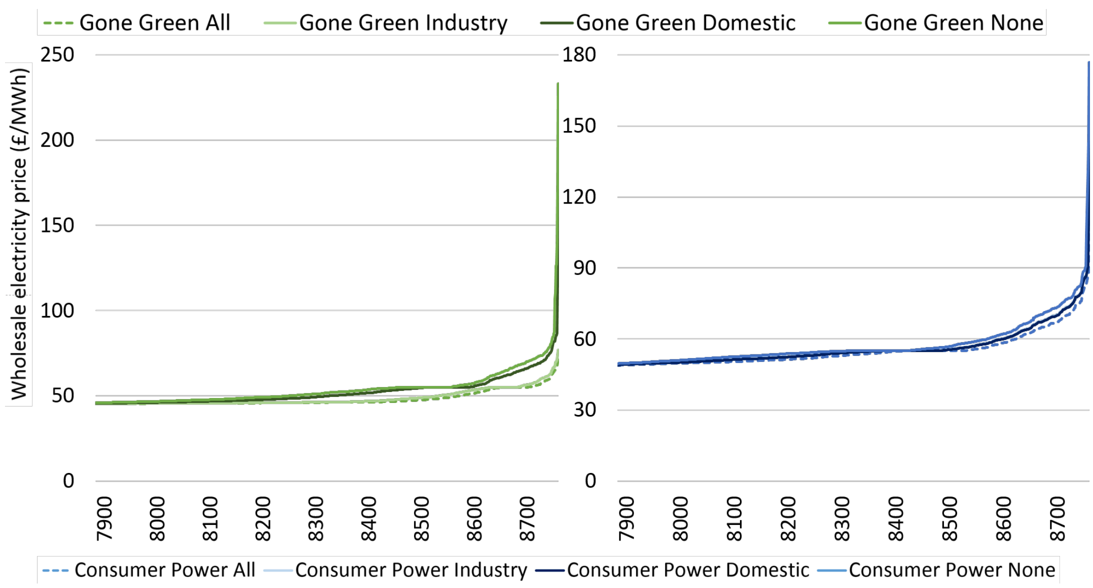


Figure 5.36: Price duration curves for Gone Green (left) and Consumer Power (right), with all, industry, domestic, and no peak reduction applied, after storage

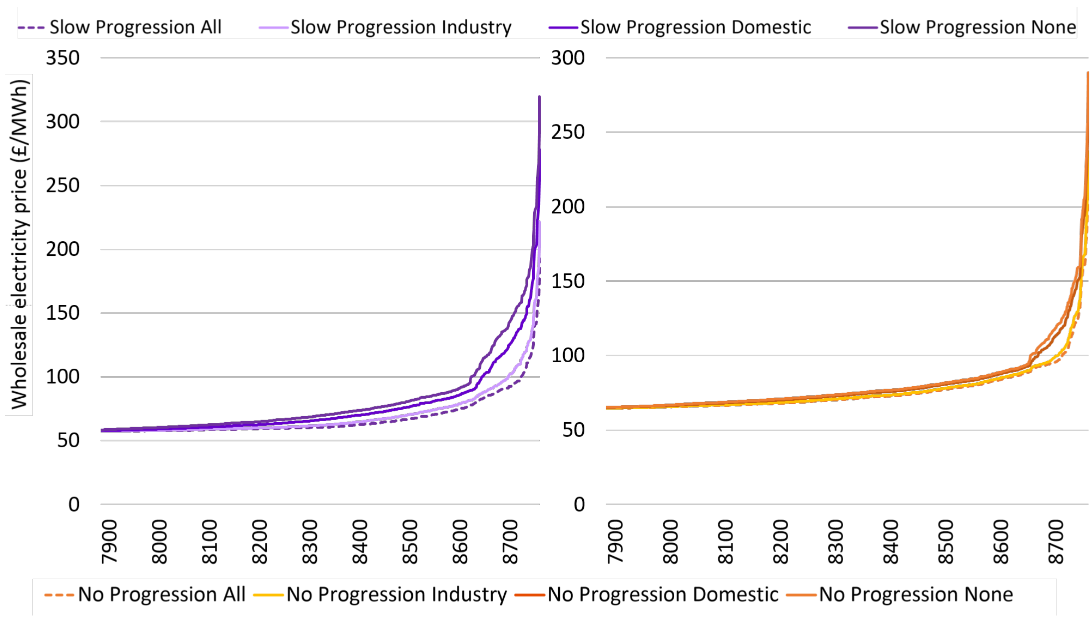


Figure 5.37: Price duration curves for Slow Progression (left) and No Progression (right), with all, industry, domestic, and no peak reduction applied, after storage

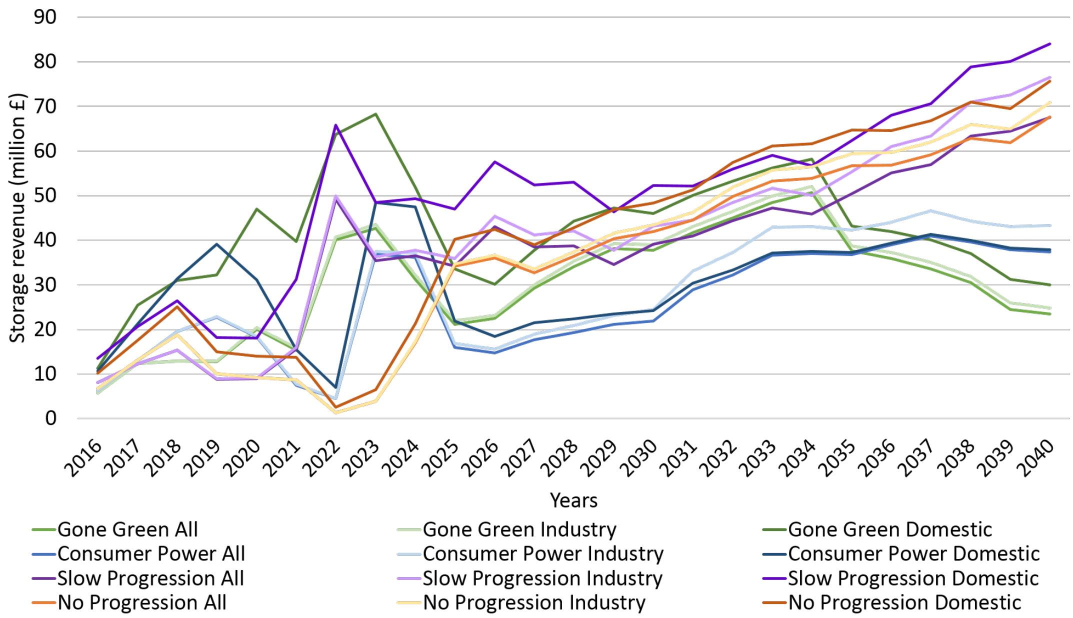


Figure 5.38: Storage revenue for different DSM scenarios

which is considerably higher than in Gone Green, which is due to the differences predicted for each category.

Figure 5.37 shows the price duration curves for the Slow Progression and No Progression FES. There is less DSM and less storage and thus the resulting peak prices are much higher than in Figure 5.36. However, the more peak reduction, the smaller the peak prices, even though in the case of Figure 5.37 the difference between the highest peak price in the None category and lowest peak price in the All category is less significant than in Figure 5.36 for Gone Green and Consumer Power, since in those two FES there is more peak reduction.

Figure 5.38 displays the differences in storage revenues after different capacities of DSM based on NG FES are applied in the model. As the DSM capacity increases, the revenue storage can obtain falls by about 20%. This is because price peaks get lower leading to storage earning less money since it can no longer perform arbitrage to the same extent due to the implementation of DSM. Due to DSM, price peaks are no longer observed, resulting in an overall decrease in storage revenue. When there is no DSM applied the revenue rises almost to £100 million in the case of Slow Progression and No Progression towards the end of the studied period and in comparison drops to a little above £25 million in 2040 when Gone Green All peak reduction is applied. Although useful when trying to achieve less volatility in the market and decrease wholesale electricity prices, DSM is a direct competitor to storage, decreasing its revenue by eliminating its top hours when storage profits from peak prices the most.

Figure 5.39 shows the standard deviation of the wholesale electricity price from 2016 to 2040 and highlights the expected fall of price volatility under DSM application. Where there is more

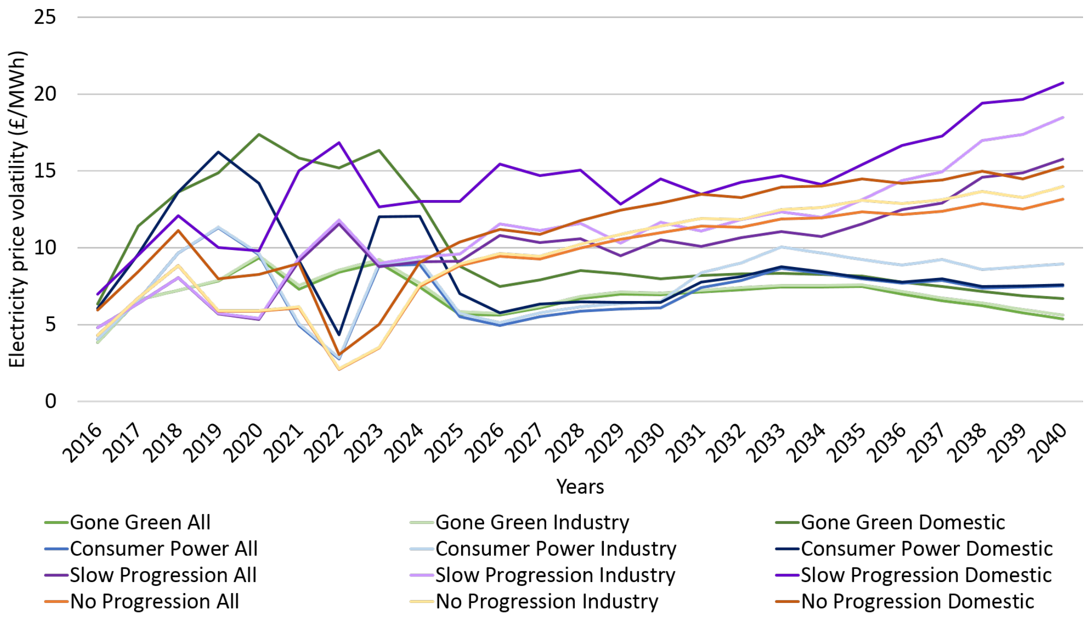


Figure 5.39: Standard deviation in wholesale electricity prices for different DSM applications

peak reduction, such as in the case of Gone Green and Consumer Power FES, especially the All scenario, volatility is smaller. This is because price peaks that cause a higher volatility are cut to a larger extent than in comparison to other DSM scenarios. There is a correlation between a larger peak reduction, lower volatility, and as a result of that lower storage revenue. Lower volatility and lower storage revenue also lead to a lower incentive in building natural gas-driven thermal generation, since if an investor is keen on building a peaker plant, he or she would benefit from high price volatility and price peaks, since this is how peaking power plants earn their profit and use high electricity prices to cover their sunk costs. If the price peaks are not observed in the market anymore as different technologies are dampening it sufficiently, there is a lack of incentive since the risk increases that the initial investment will not be paid off during the peaker plant operation.

5.10.1 Conclusion

A very important benefit of demand response when it comes to market improvement is the reduction of price volatility in the spot market. Demand responsiveness reduces the ability of the main market players to exercise power in the market. This phenomenon is due to the fact that generation cost increases exponentially near maximum generation capacity. A small reduction in demand will result in a big reduction in generation cost and, in turn, a reduction in electricity price (Albadi and El-Saadany, 2008).

This means that for DR programmes to really take off it is of foremost importance that the information and updates on how they function and how they can impact the costs end consumers must pay are readily available to current and potential clients, since if participation is too low so is their impact, which could in turn lead to turning away existing clients from further participation. Even though very high wholesale electricity prices are normally only observed during the winter period there should be incentive for consumer engagement during other seasons as well. An uncharacteristically hot summer month could lead to an increase in air conditioning use, however, consumers would not be willing to give up other daily energy use such as the use of hair dryers as they do not pay real-time prices and these spikes are insignificant to them from a cost perspective.

Even though price reductions resulting from peak reduction might seem trivial and not cost-effective when compared to the cost of device installation and implementation and maintenance of these programmes the reduction should not be overlooked as electricity demand is on the rise. Demand increases are expected due to population growth and increased electrification of sectors such as heat and transport. A shift from fossil fuels to electricity, combined with greater uptake of renewables, has been identified as a means of improving diversity of energy supply and meeting greenhouse gas emission reduction targets (Element Energy, 2012).

In recent years, demand has been lower due to the financial crisis and the impact the crisis has had on individual households, especially those that fall in the lower income category. The increase in energy consumption is expected to rise as paying electricity bills becomes a less strenuous feat for people of different economic backgrounds. However, heavy energy use and spiky demand curves will continue to pose problems for generators and utility companies so it is important to maintain the load profile as flat as possible (Albadi and El-Saadany, 2007).

The Electricity Market Reform allowed demand response and demand side management to become a part of the British energy policy domain, yet a lack of effort to develop a convincing business case for DSM has failed to persuade the consumers that policy makers are actively trying to make DR an equal actor within the British electricity market (Bradley *et al.*, 2012).

The initial ideas behind pushing DSM to a wider market, to increase consumer energy use awareness, regulation, and control, decrease costs, and enable two-sided communication, all seem attractive and feasible. In the end, however, most consumers will only be willing to participate in such programmes if they are able to see by how much the participation cuts down their energy costs.

The largest component of an energy bill is the electricity wholesale cost, which is very volatile and unpredictable, yet it makes up more than 40% of a British electricity bill (Ofgem, 2017h). For an average consumer, unable to differentiate between suppliers or determine how the electricity price is formulated, the justification of massive movements of electricity prices is insufficient. The smaller components of the energy bill, such as taxes, are out of the company's control and largely rely on the government policies and regulations. Thus, the best way for utilities to make an impact on potential and existing clients, is for them to demonstrate their willingness to reduce the biggest share of the bill. Since electricity prices are the result of a balance between supply and demand, and because supply has to be consistent, the only way this can be achieved is through regulating the demand side. It gives the consumers the idea that they are in charge of their energy finances and their efforts in reducing energy use are then made worthwhile with smaller energy bills.

As far as industrial consumers are concerned, load shifting could result in unwanted rescheduling costs, higher than the energy bill at the end of the month. Production processes usually require a significant amount of time to start and cease operation so they are not flexible enough to participate in demand response schemes. A way to include industrial customers in DSM initiatives is by urging them to employ the use of less energy intensive machinery. Such energy efficiency measures could also be encouraged by government policy in an effort to support smaller local production and businesses. Additionally, it is important to note that some industrial processes such as cold storage and smelters can also benefit from DSM (Zhang and Hug, 2015), and in some cases it also aids with the reduction of carbon emissions (Summerbell *et al.*, 2017).

This section accounts for the inclusion of demand response in the British energy system. Peak reduction can play a very big role in reducing peak wholesale prices as Figure 5.36 and Figure 5.37 show. It can be seen on the price duration curves how the peak prices, when there is more peak reduction, decrease the highest prices of the year.

Lastly, this reduction in peak prices can have a significant impact on the consumer savings that result from the implementation of DSM, as can be seen in Figure 5.40 and Figure 5.41. On Figure 5.40 are the consumer savings from 2016 to 2040 for Gone Green and Consumer Power and on Figure 5.41 are the consumer savings for the same time frame for Slow Progression and No Progression. The bigger the DSM potential, the more the consumer, for instance, a utility company can save from not having to pay for the most expensive peaker plants to run. Figure 5.42 demonstrates the consumer savings resulting for each year from 2016 to 2040 per MW of DSM capacity, which depend on the electricity prices and capacities, for all four NG FES. The consumer savings decrease for Gone Green and Consumer Power scenarios and towards the end of the analysed period the Slow Progression and No Progression FES see the savings per MW of DSM increase. This is due to the fact that if the peak wholesale prices are higher, less DSM can contribute more by lowering these higher peak prices.

As Figures 5.40 and 5.41 show there can be big variations in consumer savings. In the Gone Green All scenario consumer savings in the year 2020 reach £664.4 million, however, for both Gone Green and Consumer Power, consumer savings begin to decrease as more storage and DSM are introduced to the system, leading to a price volatility decrease, and thus the savings are less significant. The opposite effect can be seen in Figure 5.41, which features the Slow Progression and No Progression scenarios. These two scenarios introduce the least storage and DSM capacity and thus the volatility is highest, resulting in the most savings since if there are higher peak prices, a smaller DSM capacity plays a bigger role in bringing down these

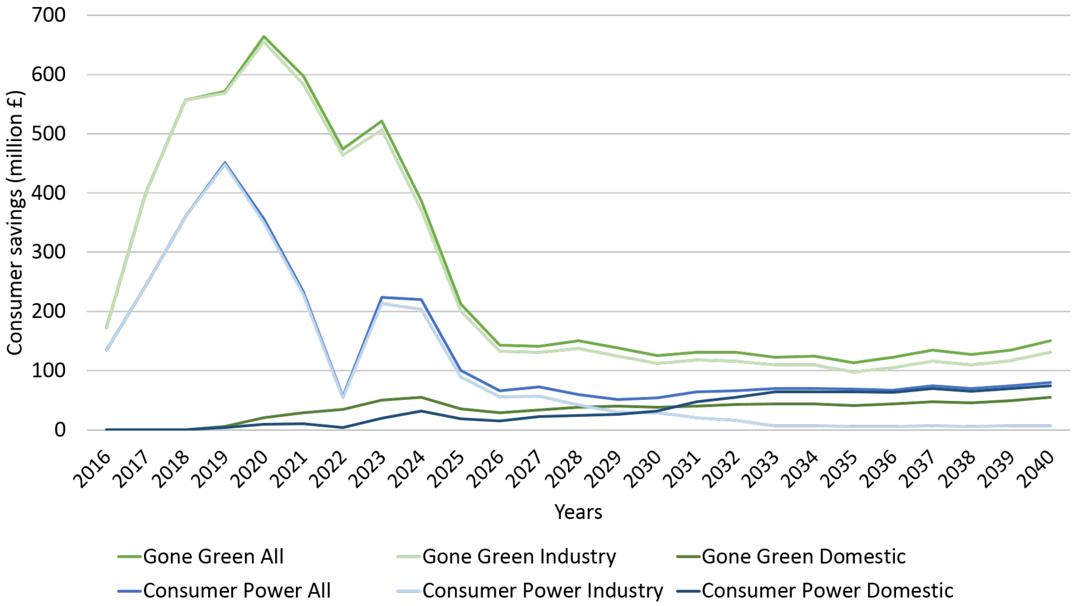


Figure 5.40: Consumer savings due to DSM from 2016 to 2040, Gone Green and Consumer Power

high prices resulting in greater savings. In addition to the flexibilities bringing the prices down, another reason for these results are the interconnectors, of which there is a greater capacity in the Gone Green and Consumer Power scenario as discussed in section 5.9.3. Less or no capacity gap as seen in Figure 5.10 also plays an important role, and in comparison to Gone Green and Consumer Power, Slow Progression and No Progression have a bigger capacity gap, which contributes to the savings results observed in Figure 5.41. This goes to show what a significant impact the implementation of DSM as a result of good policy can have on all market actors.

The introduction of demand side management can result in significant financial benefits, which agrees with the results of this thesis. Davito *et al.* (2010) propose that DSM could translate into as much as \$59 billion in societal benefit by 2019. Faruqui *et al.* (2010) estimate that the provision of dynamic pricing, which reduces peak demand and lowers the need for building and running expensive peaking power plants, could have a present value of savings in peaking infrastructure as high as £60 billion for the EU if policy-makers can overcome barriers to consumers adopting dynamic tariffs. The economic benefits of DSM for the Nordic countries are detailed in (Parkkonen, 2016).

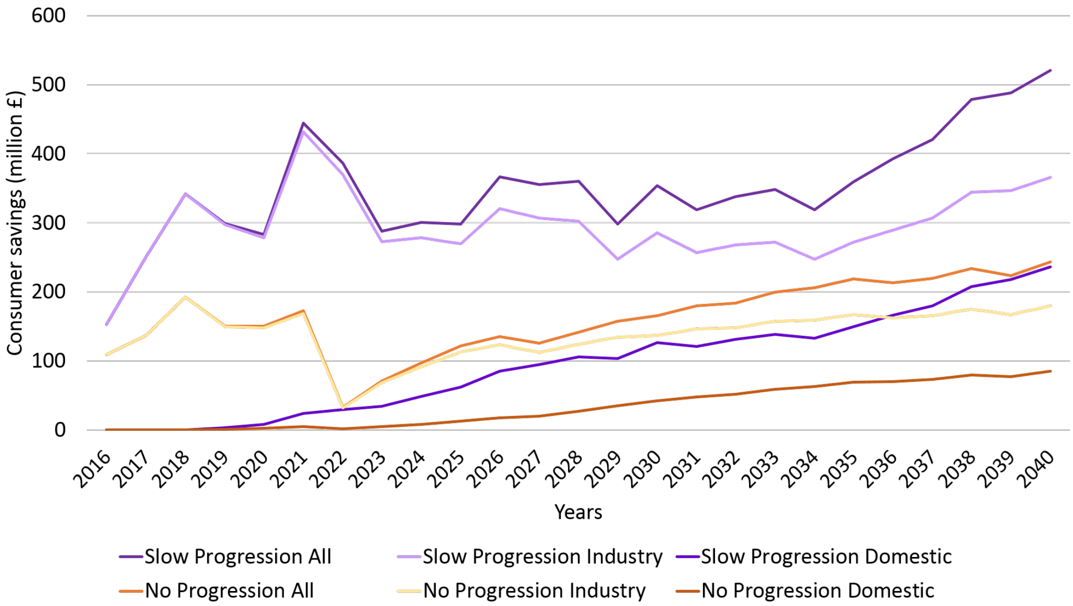


Figure 5.41: Consumer savings due to DSM from 2016 to 2040, Slow Progression and No Progression

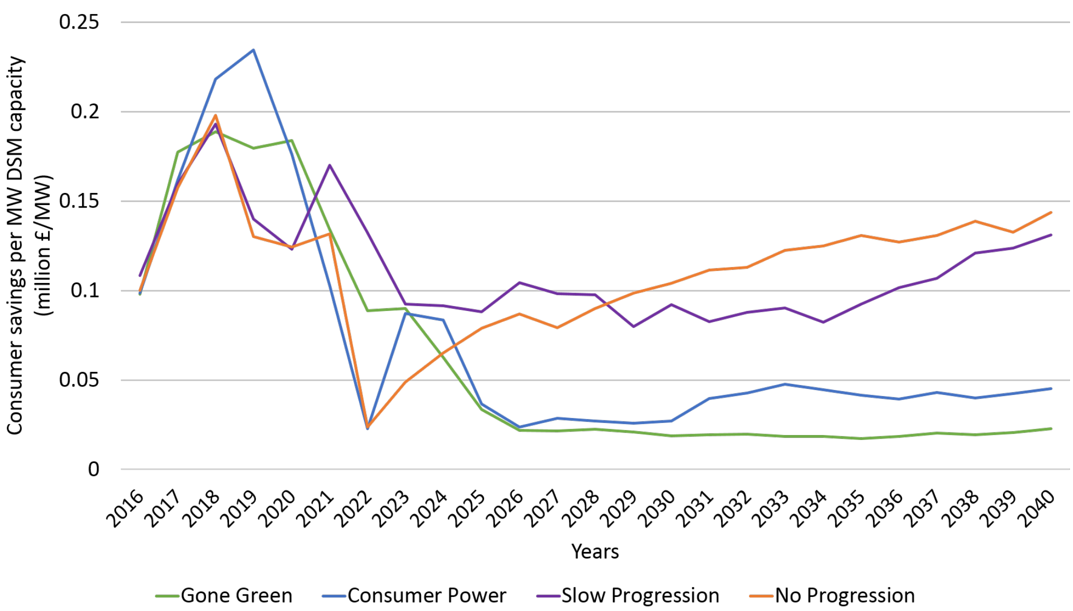


Figure 5.42: Consumer savings per MW of DSM capacity for all four FES

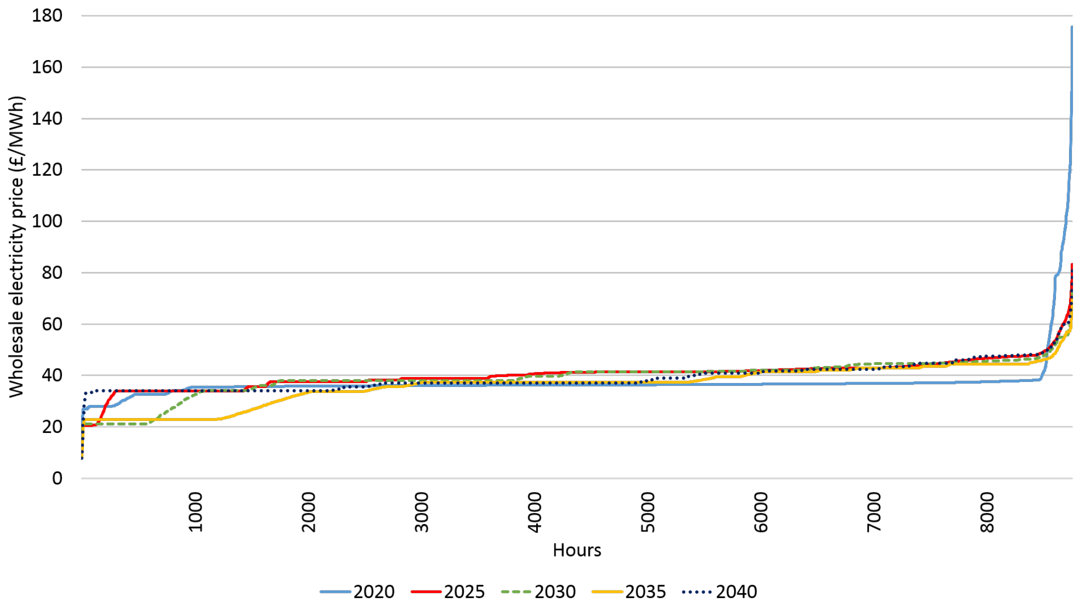


Figure 5.43: Price duration curve of wholesale electricity prices for Gone Green for years 2020, 2025, 2030, 2035, and 2040 - not capped. The colour is year-specific and the dash type is not supposed to mark a specific year and was chosen to improve visibility.

5.11 Validation of model results

The validation of results for the simulated future wholesale electricity price is demonstrated in five year time steps from 2015 to 2040. The validation of 2015 results can be seen in section 5.2, where it is plotted against the actual historical prices from that year, given that it was used as a reference year for all the future years. The colours used for the years are the same in every figure, however, the dash types aren't. The dash types were adjusted for improved visibility and differentiation purposes between the represented years.

Figures 5.43 and 5.44 show the price duration curve showing the distribution of prices for years 2020, 2025, 2030, 2035, and 2040, for the Gone Green scenario. Figure 5.43 shows the entire range of prices reached throughout the years, with 2020 reaching much higher peak prices than the other years. Highest peaks tend to happen when there is insufficient generation capacity. This is due to the expensiveness of the OCGT capacity, which is used to fill in for the missing capacity so that demand is met, which in turn leads to higher wholesale electricity prices. The prices in Figure 5.44 are capped at 100 £/MWh for clarity purposes, however, in the simulations they reach 176 £/MWh in 2020, whereas they also never go over 180 £/MWh in other years.

In Figure 5.45, the price duration curves for the Consumer Power FES are displayed. The Consumer Power scenario features less renewable generation capacity than Gone Green and the peak electricity prices for not just 2020, but also for 2035 and 2040 reach a higher number than the peak prices seen in Figure 5.43.

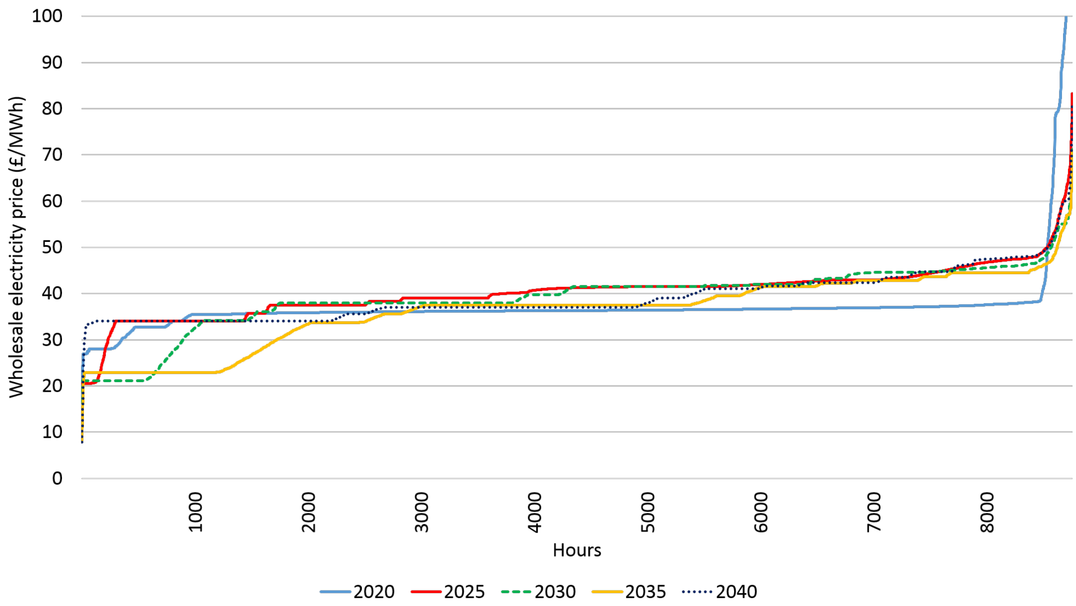


Figure 5.44: Price duration curve of wholesale electricity prices for Gone Green for years 2020, 2025, 2030, 2035, and 2040 - capped. The colour is year-specific and the dash type is not supposed to mark a specific year and was chosen to improve visibility.

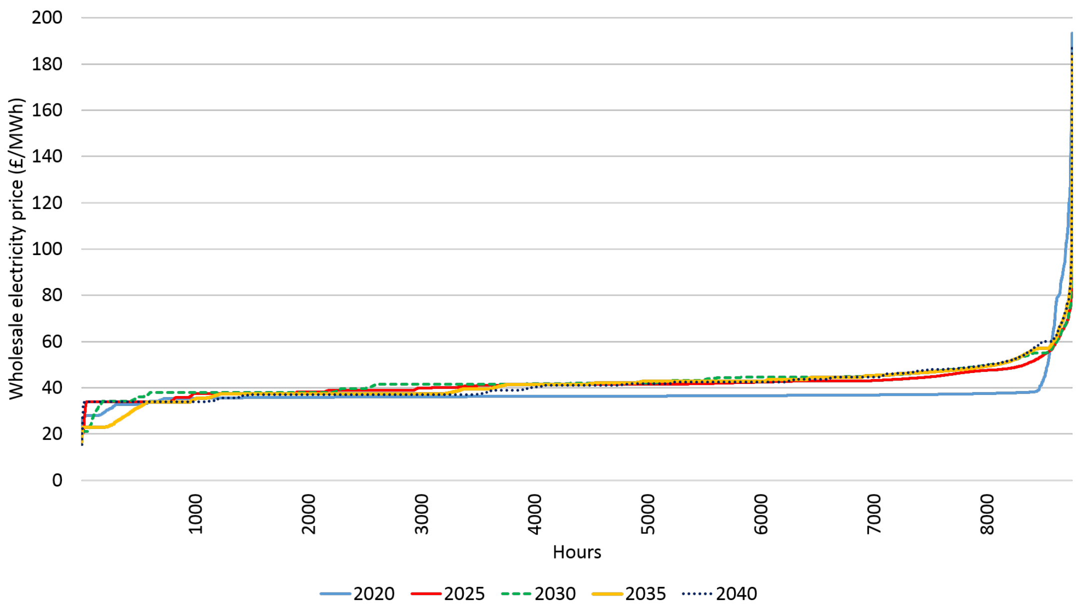


Figure 5.45: Price duration curve of wholesale electricity prices for Consumer Power for years 2020, 2025, 2030, 2035, and 2040. The colour is year-specific and the dash type is not supposed to mark a specific year and was chosen to improve visibility.

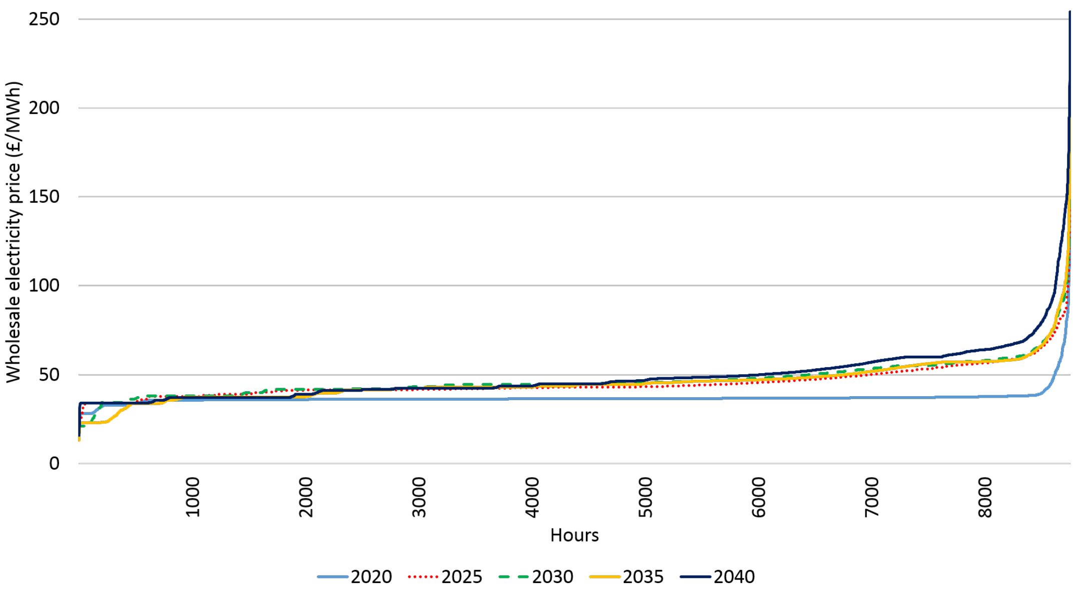


Figure 5.46: Price duration curve of wholesale electricity prices for Slow Progression for years 2020, 2025, 2030, 2035, and 2040. The colour is year-specific and the dash type is not supposed to mark a specific year and was chosen to improve visibility.

The trend of less renewable generation capacity coupled with high peak electricity prices continues in Figure 5.46, where the prices for the Slow Progression scenario are displayed. The prices in the year 2040 reach almost 255 £/MWh.

A more uniform curve pattern can be seen in Figure 5.47, displaying the prices for the No Progression scenario. Here, there is less change in generation capacity, and barely any new renewable generation capacity is installed, and thus the price duration curves follow a similar pattern. This is due to the fact that in the No Progression scenario, the natural gas and coal-fired generation capacity is still very heavily represented and the variable costs of the two technologies are very close. The uplift approach used in this work is based on increasing the variable cost to the level of the next higher technology and if the difference is small, the cost doesn't increase for a long period in the merit order, which then directly impacts the electricity prices, which as a result are very similar.

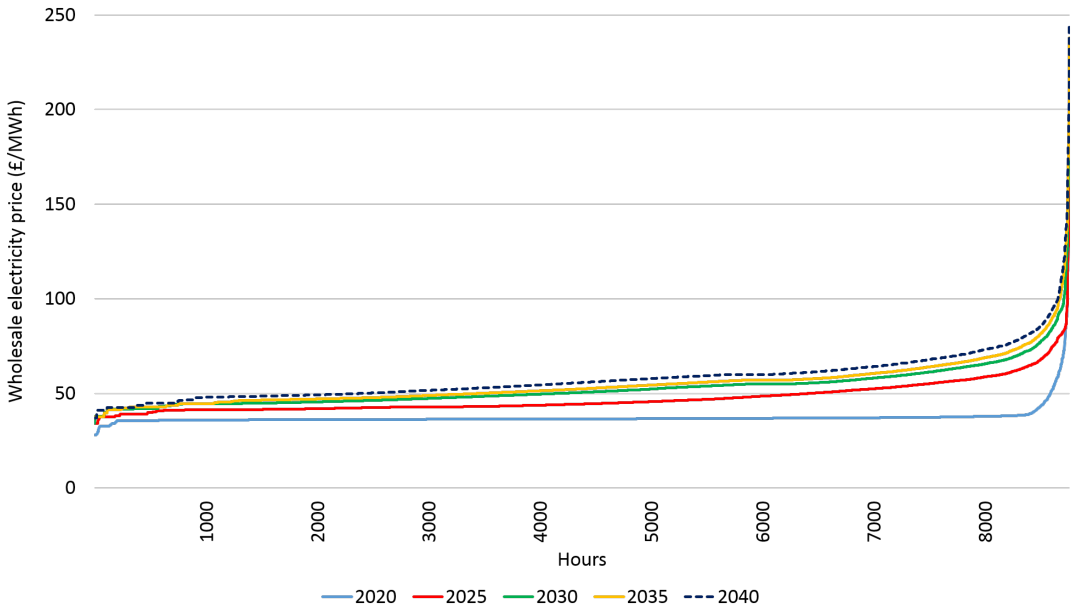


Figure 5.47: Price duration curve of wholesale electricity prices for No Progression for years 2020, 2025, 2030, 2035, and 2040. The colour is year-specific and the dash type is not supposed to mark a specific year and is chosen at random to improve visibility.

5.12 Chapter summary

This chapter presented the outcome resulting from using the merit order model and its submodels described in Chapter 4. Discovering the future fluctuations in British wholesale electricity prices largely depends on the three step process, where the three low-carbon technologies - renewable generation, energy storage, and demand side management - are evaluated separately and jointly in the end. Each section focuses on the prices resulting from the implementation of each technology. When comparing the resulting prices from Figure 5.16 to other long-term wholesale electricity price predictions it can be seen that the outcomes of this modelling approach, especially in the case of Gone Green and Consumer Power parameters, which have a bigger renewable generation capacity, do not lead to significantly increased wholesale electricity prices in GB. In NG FES (National Grid, 2016b), it is unclear what are the parameters used to plot the high, base, and low case price scenarios. However, National Grid does not include wholesale price predictions for each of their key energy scenarios, Gone Green, Consumer Power, Slow Progression, and No Progression, which is the case in this thesis. In their reports NG does not disclose why the chose to predict the wholesale electricity prices based on three different scenarios, but it is only in this thesis that the parameters of their four FES are implemented and the results are studied. The Department for Business, Energy, and Industrial Strategy predicts only a high and low wholesale electricity price scenarios, which result in a linear increase of wholesale electricity prices. However, just like NG, BEIS does not disclose how the prices were determined, what were the parameters used, and why only two, most extreme, potential scenarios were developed. Further, it is unclear whether or not BEIS accounts for demand side management as there are no examples of peak reduction or different types of DSM studied. In the case of BEIS, energy storage scenarios are also not analysed. In the case of NG, energy storage and demand side management, are included in the FES, however, it is not disclosed if and to what extent they are included in the wholesale electricity price predictions. In this work it can be seen that DSM and energy storage can be competitors to each other as storage profit decreases as a result of DSM implementation as demonstrated in Figure 5.38. However, differences in wholesale electricity prices, before and after storage, as seen in Figure 5.27, are rather small and the wholesale electricity prices undergo a small drop in numbers. The important role of DSM on the wholesale electricity market especially manifests itself in the impact it has on reducing peak wholesale electricity prices, that Figure 5.36 and Figure 5.37 show, which is something both BEIS and NG did not include in their results as well. Lastly, the results show that demand side management carries multiple benefits such as consumer savings, displayed in Figure 5.40 and Figure 5.41. Customer savings from energy storage are included in Figure 5.34. Future interconnector flows, the import/export dynamics between Britain, continental Europe, and Ireland, and the consumer savings resulting from interconnection, which can be seen in Figure 3.35 are also included in this chapter. The chapter concludes with a validation of results in five year time steps from 2015 to 2040. The 2015 simulation results are also used to validate the model itself at the beginning of the chapter.

Chapter 6

Conclusions

This chapter highlights the conclusions of this thesis. The motivation behind writing the thesis is revisited and the objectives are reiterated. The key findings of each chapter are summarised and the implications of the results are discussed. Lastly, ideas for future work are presented.

6.1 Thesis summary

This thesis aimed to improve the understanding of the impact each of the main low-carbon technologies will have on the British wholesale electricity market.

Chapter 1 of the thesis states the main motivation behind the work and the intended methods of executions. Additionally, the targets of each chapter and final goal are presented.

Chapter 2 of the thesis provides the historical background of the British electricity market. It provides the timeline from the period before the market's deregulation up to the present day. Various policy structures from Britain and Europe are presented. The regulatory framework of the market is explained and initiatives developed to secure a green energy future are discussed. Latest policy developments such as the Electricity Market Reform and the future of the market conclude the chapter.

Chapter 3 discusses the progress of low-carbon technologies in Great Britain and the development of energy policy associated with them. First, the renewable technologies included in the thesis are listed and their progress so far in addition to the policy implementation that led to it is discussed. Then, energy storage technologies that will play a significant role in the British energy mix are addressed. Finally, demand side management development on a global, European, and domestic scale is assessed.

Chapter 4 explains the merit order model and is broken into different sections, each corresponding to a part of the model. First, the modelling and inclusion of renewable generation is discussed and explained. Then, the process of modelling Britain along with the interconnections it has to other European countries is presented, followed by the method used to include demand side management. Lastly, the use of dynamic programming for the purpose of energy storage integration is explained.

Chapter 5 presents the case study, data, and results of the model. Following the order set in chapters 3 and 4, first the simulated wholesale electricity prices resulting from renewable generation inclusion in the four FES in the British energy mix are presented and discussed. Next, the interconnector flows before and after the inclusion of storage in the model are disclosed. Further, the price difference in wholesale electricity prices for all scenarios within the case study, before and after storage, and the impact of storage on the wholesale prices are discussed. Interconnector flows after energy storage and storage revenue are presented. Lastly, the impact of demand side management on the market is evaluated. Consumer savings are calculated for each of the low-carbon technologies.

6.2 Contributions

The thesis investigated the impact various low-carbon technologies will have on the wholesale electricity prices and the energy mix in Britain. Inconsistency between energy targets and their implementation has led to regulatory and commercial challenges that must be addressed in order for the energy system to continue operating without interruptions and without causing a significant financial strain on the final consumers. The objectives of the thesis were to present a comprehensive review of the British wholesale electricity market, study the implications of Government policy implementation, individually and collectively study the impact low-carbon technologies will have on the wholesale market, and present the predictions for the wholesale electricity prices as a result of model simulations.

The interdisciplinary work performed in this thesis differentiates itself from other long-term forecasting models by offering a whole systems perspective on the future of the British energy. Unlike planning models, such as the UK TIMES (UCL Energy Institute, 2017), this model focuses on the market operations and the long-term price consequences of integrating various low-carbon technologies. It differentiates itself from statistical models, which use historical prices for short-term and in some cases medium-term electricity price predictions. In terms of academic work, it offers an outlook on the development of future wholesale electricity prices in Britain. For the sake of this inclusion and to focus more on the market, this model chooses to focus less on operational development and network characteristics. This is because the operation of power plants is of lesser importance compared to economic developments for the purposes of this thesis.

The thesis provided:

- A merit order model was developed, using the Future Energy Scenarios from 2016 as a case study (National Grid, 2016b). The model somewhat expands on the work of (Dunbar, 2016), however it is no longer studying Great Britain as an islanded network but incorporates its connections with interconnected countries.
- The model includes the main types of renewable generation and does not focus on just one type of a renewable technology like wind energy. The policy background of each type of renewable technology is discussed.
- An insight into the development of demand side management in Britain. Numerous global, European, and domestic programmes, policies, and initiatives were broken down and discussed in detail to understand what is holding back a larger roll out of DSM in Britain. This was followed up with a wholesale electricity market analysis without and with the inclusion of DSM. The resulting wholesale electricity prices after applying peak reduction were presented and discussed.
- The inclusion of energy storage with the use of dynamic programming accounted for energy storage in the British energy mix and highlighted what role storage will play in the future and with which technologies it will have to compete in order to be successful in ensuring profit for itself while at the same time maintaining low electricity prices and without compromising the energy system's security. Wholesale electricity prices with and without storage were included in addition to the storage revenue. The impact of storage on interconnection was also noted.
- The thesis also included yearly, scenario-specific customer savings resulting from the use of interconnection, energy storage, and demand side management.

6.3 Key findings and conclusions

After analysing each technology's individual impact on the British wholesale electricity market, it can be said that for the market and the energy system the low-carbon technologies are a part of, to remain functional it is necessary for all three technologies, renewable energy, demand side management, and energy storage, to play a role in maintaining and improving its stability.

In terms of renewable energy, it was seen that introducing a larger capacity of renewable generation into the energy mix does not have a negative impact on the wholesale electricity prices. In fact, in the simulations performed, the largest price increase was seen in the No Progress scenario, the scenario with the least renewable capacity. This was due to the fact there was the most capacity still in the system susceptible to the changes in natural gas and to some extent coal and nuclear prices. With renewable generation that was not the case and Gone Green, the scenario with most renewable capacity had an average wholesale price in 2040 of 40.01 £/MWh, which is very close and in fact even a little smaller than the average wholesale electricity price of 2016, 42.63 £/MWh. This fits with the original thesis hypothesis, which claimed that an increased inclusion of low-carbon capacity does not have overwhelming negative long term effects on the wholesale prices of the British electricity market.

Further, when energy storage is taken into account it can be seen that it does not have any additional impact on the wholesale prices past that of renewable generation on average. Energy storage also has a role to play when it comes to securing additional capacity during peak demand, which agrees with the original hypothesis claiming that low-carbon technologies contribute to energy security.

Studying the results of demand side management it was possible to discern that the more peak reduction occurred, the less volatility was observed in the market. Demand side management reduces peak prices, which leads to less market volatility and better market operation. The lack of peak prices positions DSM as a direct competitor to energy storage, which generates most of its profit from the times of peak prices and in the results it was also seen that the higher the amount of peak reduction the smaller the storage revenues. However, storage still provided the necessary capacity for meeting peak demand, proving once more how important it is for all low-carbon technologies to be implemented together in order to prevent large price spikes, maintain sufficient capacity to prevent power outages, and secure flexible and smooth energy system and wholesale market operation.

This thesis examined the following hypothesis:

> A wider variety of types of energy generation in the British energy mix and the inclusion of low-carbon and smart grid technologies in the energy system lead to improved security of supply and do not have an overwhelmingly negative long-term effect on the wholesale prices of the British electricity market.

Following a comprehensive review of the technologies and relevant policies associated with them, model implementation, and simulation of the future British wholesale electricity prices, it can be said the hypothesis holds in the cases of the two renewable energy friendly scenarios from National Grid, Gone Green and Consumer Power. This goes to show if a detailed programme is constructed and there is a commitment to seeing it come through, high wholesale electricity prices can be avoided. If the policy put in place is too weak and the commitment to installing a sufficient capacity of low-carbon technologies only installs some of the promised generation the results seen in No Progression and Slow Progression can be considered when trying to evaluate the future wholesale prices.

However, with a consistent set of policies, directives, and initiatives put in place, and a true commitment to completely and successfully restructuring the British energy system, meaning that renewable generation doesn't come second to thermal generation, the wholesale electricity prices don't have to increase and the security of supply can be improved with the capacity gap reduced.

The results of this thesis agree with literature findings. Sáenz de Miera *et al.* (2008b) analysed the impact of renewable electricity support schemes on power prices with the case study being wind electricity in Spain. The work studied the reduction in the wholesale price of electricity as a result of more renewable generation being fed into the grid. The case of wind generation in Spain showed that this reduction is greater than the increase in the costs for the consumers arising from the renewable support scheme, which in the case of this study are the feed-in tariffs that the final consumer gets charged. This net reduction in the electricity price is positive from the consumer point of view and by doing so this work provided an additional argument for renewable support by contradicting one of the usual arguments against renewable deployment, which is the excessive burden on the consumer. Ketterer (2014) investigated the relationship between intermittent wind power generation and electricity price behaviour in Germany. The effect of wind electricity generation on the level and the volatility of the electricity price was evaluated. The results showed that variable wind power reduces the price level but increases its volatility. The results also indicated that regulatory change has stabilised the wholesale price. Another case study on Germany (Sensfuß *et al.*, 2008) analysed the claims that the costs of renewable generation for consumers are too high by analysing the impact of renewable generation on spot market prices. The results generated by an agent-based simulation indicated a considerable price decrease due to the impact of renewable energy generation. In the short run, this gives rise to a distributional effect which creates savings for the demand side by reducing generator profits.

Bublitz *et al.* (2017) determined the drivers and their contribution behind the decreasing wholesale electricity prices in Germany in recent years. The electricity market transition is shaped by different key factors, such as the expansion of renewable energies, the changes in the EU carbon trading scheme, and the European market integration. In addition, markets are affected by the volatile prices of natural gas and coal. The development of these different factors led to a decline of German wholesale electricity prices of almost 40%. With the use of an agent-based model the effect of these drivers was analysed. Although, renewable generation expansion has been found to have a significant impact on the price decline, the impact of carbon and coal prices on electricity prices has been even more significant in the case of Germany.

Green and Vasilakos (2010) evaluated the impact of intermittent wind generation on hourly equilibrium prices and output, using data on expected wind generation capacity and demand for 2020. Hourly wind data for the period 1993-2005 were used to obtain wind output generation profiles for thirty onshore and offshore regions across Great Britain. After the wind profiles for each month were matched to the actual hourly demand, which was scaled to possible 2020 values, it was determined that the volatility of prices will increase and that above-average wind speeds lead to below-average prices.

Brancucci Martinez-Anido *et al.* (2016) investigated the impact of wind power on electricity prices using a production cost model of the Independent System Operator for the New England power system. Different scenarios in terms of wind penetration, wind forecasts, and wind curtailment were modelled in order to analyse the impact of wind power on electricity prices for different wind penetration levels and for different levels of wind power visibility and controllability. The results found that wind penetration decreases electricity prices, however, the analysis concluded that electricity price volatility increases even as electricity prices decrease with increasing wind penetration levels.

The selection of NG's Future Energy Scenarios for the case study was crucial for the thesis since the scenarios provide a comprehensive coverage of the future power system in Great Britain and an overall bigger focus on the energy system than on climate change. It was important that the chosen scenario included predictions regarding the greenhouse gas emissions in Britain and the related policies, due to the legal obligation GB has to decreasing the harmful emissions. The majority of future energy scenarios for Britain available primarily focus on predicting climate change regulations and related development, however, for this thesis it was imperative that the scenario chosen also offers significant information on the power sector development, which FES do. As a consequence of that the assumptions regarding capacity, fuel prices, and demand are influenced by the numbers provided in FES that might differ in other energy scenarios. However, those scenarios might not provide a complete picture of the future power system so the FES were still preferred. National Grid also provided future energy price predictions for natural gas, coal, and carbon. They offered three different price scenarios - low, base, and high. Given that this thesis followed the base price scenario and thus the impact of the higher or lower price options was not studied. In terms of storage operation, only two types of storage were aggregated into one storage unit, even though it is predicted a wider variety of storage will be implemented in the system. The two storage types, PHES and Li-ion battery, are predicted to have the biggest capacity, and thus storage operation in this model mimics the characteristics of these two types. The thermal generation in the thesis was grouped in four different groups meaning that power plant characteristics were not detailed leading to a dampened impact of operational characteristics on power market results. Specific assumptions were made about power plants characteristics and their availability that were kept constant throughout every thermal generation group and throughout all the years studied. However, this is still a simplification of reality as it is very difficult to predict behaviour in scarcity times. Another relevant assumption was the adoption of 2015 as the base year. The year was windier than average (RenewableUK, 2017), which could lead to an impact on electricity price level and volatility. The case of increased wind generation, as literature (Brancucci Martinez-Anido *et al.*, 2016), (Sáenz de Miera *et al.*, 2008b), (Green and Vasilakos, 2010) would suggest, leads to decreased electricity prices. However, a sensitivity study was performed in section 5.8.1 demonstrating that the impact of the base year in this work was not significant enough to result in drastic price pattern changes.

6.4 Further work

There are three improvements proposed that could further enrich the work of this thesis:

- All types of renewable generation listed in National Grid's Future Energy Scenarios are also included in this thesis. However, real-time data was available only for solar PV and onshore and offshore wind generation. Due to the infancy stages of tidal and wave energy generation there were no time series available. Models could be developed to generate time series for wave and tidal energy. Including time series of marine generation would also allow to better assess when wind and solar generation are needed and how they can work in unison. It would also give further clarity on the impact marine generation can have on the wholesale electricity prices. This being said, marine generation will continue to play a minor role in the British energy generation mix in the future even if all planned projects are materialised on time, thus there is some uncertainty whether or not these projects will even be contributors to the energy system. Due to the limited capacity of potential projects, their impact on the future wholesale electricity prices would be minimal and for this reason generating marine time series was not pursued further in this thesis.
- This thesis modelled Great Britain not as an islanded network as it included the interconnections it has with other countries. The interconnected capacities were based on Government and industry reports, which, however, according to the National Grid do not include all the projects in development. Further, the electricity price for each country stayed the same throughout the entire year. This is because more detailed predictions were not made in the cases of countries which published their national energy outlooks such as the Netherlands, which only included yearly predictions, or because some countries like Belgium had no such outlooks published and basic merit order models had to be developed for these countries in order to even obtain the electricity price for each year. To give this work more validity a detailed merit order could be developed for each country Britain has or will have interconnections with, similar to the one developed for the purposes of this thesis. The model would result in simulated wholesale electricity prices for all these countries in half-hourly or hourly intervals. Using these prices would result in more realistic simulated wholesale electricity prices for the British market as well. However, in order to accurately model the markets of the countries Britain has interconnections with it would also be necessary to model the countries those countries have interconnectors with, spanning across most of the European continent. This would result in having to model all of the electricity markets in Europe for which data is not easily available and because of that further modelling might not lead to much improved results of the British wholesale electricity prices.

- The use of the model developed in this thesis is for whole systems modelling, however, unlike some models, in this thesis the specific focus is on the electricity market. The economics aspect is thus explored more than the operations background. This model does not take into account power plant characteristics, such as start up time or ramp rates. The relevancy of such characteristics is less significant due to the fact that this thesis deals with long-term forecasting and future plant characteristics are uncertain as they change over time. Such a model simplification in a scenario with large amount of renewable capacities such as Gone Green can lead to overestimating wind generation and subsequently underestimating the abilities of thermal generation. In real world applications this can lead to less certainty when it comes to capacity investment planning. However, as this thesis follows pre-established capacity installation decisions, the interest is not regarding what capacity should be built but how does the planned capacity impact the British wholesale electricity market in the long term. The model does not account for grid characteristics as it is difficult to predict the changes in network investment during the 25 year period studied in this thesis. This is consistent with other long-term forecasting models such as the UK TIMES model (Daly and Fais, 2014). Including these characteristics could allow to study operations more as such an inclusion would result in more realistic operational results, however, including these specifics is not compatible with long-term forecasting and a trade-off had to be made between a focus on operational or market characteristics, of which the latter was chosen.

Appendix A

Publications

The work detailed in this thesis has been published in four publications, which were all presented at their respective conferences. Furthermore, the results of this doctoral work that were not included in the thesis were presented at the International Association for Energy Economics conference in 2017. All publications and presentations are listed and briefly described below.

M. Ruppert, **S. Lupo**, V. Slednev, and W. Fichtner 'The Impact of Increasing Renewable Generation on the Operational Cost in the British Electricity Transmission System ,' 40th IAEE International Conference - Meeting the Energy Demands of Emerging Economies. Implications for Energy and Environmental Markets, 2017.

S. Lupo, M. Ruppert, A.E. Kiprakis, and V. Slednev, 'Analysing the Effect of Increasing Renewable Capacities in Great Britain on the Regional Allocation and Wholesale Prices,' 24th International Conference on Electricity Distribution, 2017.

S. Lupo and D.M. Reiner, 'How does changing the penetration of renewables and flexibility measures affect the economics of CCS penetration?,' 13th International Conference on Greenhouse Gas Control Technologies, 2016.

S. Lupo and A.E. Kiprakis, 'The Impact of Demand Side Management on the Wholesale Prices of the British Electricity Market,' BIEE - 11th Acad. Conf., no. September, 2016.

S. Lupo and A.E. Kiprakis, 'The Impact of Renewable Energy Resources on the Electricity Prices of the United Kingdom,' 13th Int. Conf. Eur. Energy Mark. EEM, 2016.

At the European Energy Markets conference in 2016 the work studying how the renewable generation will shape the British wholesale electricity market was presented. The work did not include energy storage or demand side management and it focused specifically on renewable generation capacity as predicted by National Grid's FES for 2015.

In the same year the impact of demand side management was presented at the conference of the British Institute of Energy Economics. Demand peak reduction was applied to four days in every astronomical season to see how it would impact the British wholesale electricity market.

In November 2016, the paper studying real options valuation applied to CCS scenarios was presented at the 13th International Conference on Greenhouse Gas Technologies, which contained some of the initial results of the real options analysis.

Lastly, the paper presented at the International Conference on Electricity Distribution in 2017 discussed the optimal locations for renewable energy installation based on the predictions from National Grid and grid constraints and analysed what impact they would have on the British wholesale electricity prices. The results of the paper suggest that location does not have a significant impact on the wholesale electricity prices and thus wasn't further investigated for the purposes of this thesis.

Appendix B

Demand and fuel cost information

Table B.1 shows the fuel cost for every generation technology from 2016 to 2040.

Table B.2 shows the annual demand for every scenario from 2016 to 2040.

Table B.3 shows the average residual demand for every scenario from 2016 to 2040.

Table B.4 shows the maximum residual demand for every scenario from 2016 to 2040.

Table B.5 shows the minimum residual demand for every scenario from 2016 to 2040.

Table B.6 shows the minimum demand for every scenario from 2016 to 2040.

Table B.7 shows the average cold spell peak demand for every scenario from 2016 to 2040.

Table B.1: Generation technology-specific fuel costs from 2016 to 2040

Technology	Gas (pence/therm)	Coal (£/tonne)	Nuclear (£/kg)	Carbon (£/tonne CO2)
2016	40.9	43.0	42.7	24.5
2017	42.0	41.6	42.8	25.2
2018	43.0	45.1	43.7	25.4
2019	44.2	46.8	43.9	25.8
2020	45.4	48.0	44.8	25.9
2021	46.8	49.8	46.9	26.0
2022	48.6	50.6	48.4	26.2
2023	50.0	51.5	50.9	26.5
2024	51.4	51.8	54.6	26.9
2025	53.0	52.7	57.4	28.0
2026	54.8	53.2	59.4	28.6
2027	55.6	53.4	60.2	29.6
2028	56.0	53.1	60.6	30.5
2029	56.6	53.5	61.1	31.5
2030	56.7	54.3	61.3	32.3
2031	56.9	55.0	61.1	33.1
2032	57.0	55.5	60.9	33.86
2033	57.2	55.8	60.7	34.8
2034	57.4	56.1	60.5	35.5
2035	57.9	56.3	60.3	35.9
2036	58.3	57.1	60.7	36.46
2037	58.7	57.7	60.5	36.6
2038	59.1	58.6	60.3	36.99
2039	59.5	59.6	60.4	37.33
2040	59.8	60.2	60.4	37.5

Table B.2: Annual demand for every FES from 2016 to 2040

Demand (TWh/year)	Gone Green	Consumer Power	Slow Progression	No Progression
2016	331	333	330	332
2017	328	330	328	332
2018	326	327	327	331
2019	324	326	325	331
2020	322	326	324	330
2021	321	326	322	329
2022	322	324	320	328
2023	323	324	320	327
2024	325	324	319	326
2025	327	324	319	325
2026	330	325	319	324
2027	334	326	318	323
2028	338	327	318	323
2029	342	329	318	323
2030	346	331	318	322
2031	350	333	319	322
2032	355	336	320	323
2033	359	338	322	324
2034	363	340	323	324
2035	366	342	323	325
2036	370	344	324	326
2037	374	346	325	327
2038	377	348	326	328
2039	381	350	328	330
2040	384	352	329	331

Table B.3: Average residual demand

Demand (MWh/year)	Gone Green	Consumer Power	Slow Progression	No Progression
2016	29325	29409	29239	29612
2017	27967	28551	28427	29090
2018	27004	27374	27588	28495
2019	26057	26738	26848	28184
2020	25002	26090	26361	27790
2021	23352	25393	25392	27146
2022	22477	24680	24231	26760
2023	21243	23667	23743	26618
2024	20287	22802	22622	26069
2025	19427	21755	21623	25586
2026	18764	20828	20923	24935
2027	18295	21768	20601	24298
2028	17995	21608	20277	24032
2029	17799	21074	19541	23829
2030	17877	20678	19256	23771
2031	18067	20657	18939	23846
2032	18298	20548	18696	25366
2033	18598	20618	18493	25619
2034	18886	20476	18332	25848
2035	19149	20535	18344	26139
2036	19478	20588	18350	26461
2037	19679	21010	18711	26946
2038	20007	21382	18809	27238
2039	20178	21540	18940	27600
2040	20519	21733	19077	27890

Table B.4: Maximum residual demand

Demand (MWh/year)	Gone Green	Consumer Power	Slow Progression	No Progression
2016	56543	56739	56763	56555
2017	55637	56332	56590	55968
2018	55389	55788	56420	55669
2019	55008	55310	56269	55023
2020	54462	55622	56135	55087
2021	54163	55621	56131	54722
2022	54876	55432	55863	54298
2023	54830	55299	55885	54147
2024	55570	55401	55756	54096
2025	55893	55448	55628	54008
2026	56652	55640	55490	53937
2027	57622	57198	55601	53826
2028	58504	57626	55708	53795
2029	59100	57796	55785	53632
2030	60101	58256	55753	53480
2031	60906	58634	55735	53406
2032	61727	59024	57386	53456
2033	62468	59566	57821	53444
2034	63405	59866	57908	53506
2035	64058	60220	58135	53510
2036	64831	60566	58453	53503
2037	65307	61228	58902	53905
2038	66197	61827	59229	54007
2039	66678	62222	59684	54130
2040	67388	62731	60222	54444

Table B.5: Minimum residual demand

Demand (MWh/year)	Gone Green	Consumer Power	Slow Progression	No Progression
2016	9826	9676	10703	9833
2017	7372	7835	9491	8098
2018	5400	5661	8254	6372
2019	3643	4584	7592	5357
2020	1744	2827	6964	4327
2021	-1455	1153	5720	2663
2022	-3989	-587	5106	458
2023	-6911	-3111	4779	-698
2024	-9744	-5569	3750	-3162
2025	-12245	-8344	2848	-5515
2026	-14585	-10971	1656	-7281
2027	-16731	-11325	325	-8399
2028	-18496	-12614	-275	-9494
2029	-19798	-14312	-712	-11182
2030	-20765	-15820	-715	-12004
2031	-21304	-16593	-532	-12851
2032	-21720	-17530	896	-13613
2033	-21959	-18168	1354	-14275
2034	-22325	-19050	2245	-14957
2035	-22521	-19545	3007	-15239
2036	-22657	-20023	3861	-15471
2037	-22811	-20051	4493	-15329
2038	-22941	-20061	4856	-15420
2039	-23090	-20271	5299	-15443
2040	-23078	-20417	5568	-15526

Table B.6: Minimum demand

Demand (MWh/year)	Gone Green	Consumer Power	Slow Progression	No Progression
2016	21661	21748	21739	21435
2017	21321	21452	21681	21323
2018	21115	21156	21594	21250
2019	20875	20989	21595	21199
2020	20587	20696	21380	20824
2021	20266	20491	21206	20586
2022	19736	20203	21130	20401
2023	19803	20182	20888	20391
2024	19568	19990	20786	20265
2025	19662	19905	20712	20194
2026	19649	19779	20581	20098
2027	19590	19826	20443	20159
2028	19644	19819	20322	20158
2029	19869	19950	20204	20251
2030	19917	19867	20128	20358
2031	20082	19945	20136	20440
2032	20267	20090	20095	20532
2033	20486	20115	19935	20690
2034	20556	20226	19977	20810
2035	20737	20317	20000	20956
2036	20913	20404	19961	21087
2037	21161	20555	19904	21209
2038	21211	20701	19959	21386
2039	21474	20816	19947	21572
2040	21625	20871	19870	21638

Table B.7: Average cold spell peak demand

GW	Gone Green	Consumer Power	Slow Progression	No Progression
2016	60.8	61.0	60.8	61.0
2017	60.3	60.7	60.3	60.9
2018	60.2	60.4	60.1	60.8
2019	59.9	60.3	59.8	60.7
2020	59.7	60.7	59.9	60.8
2021	60.0	61.0	59.8	60.8
2022	60.9	60.9	59.5	60.6
2023	61.0	60.9	59.4	60.6
2024	61.9	61.2	59.5	60.5
2025	62.4	61.4	59.5	60.4
2026	63.3	61.7	59.5	60.3
2027	64.4	61.9	59.3	60.3
2028	65.4	62.3	59.3	60.4
2029	66.2	62.6	59.2	60.5
2030	67.3	63.2	59.1	60.5
2031	68.3	63.7	59.2	60.5
2032	69.3	64.2	59.4	60.7
2033	70.1	64.8	59.5	61.1
2034	71.1	65.2	59.6	61.2
2035	71.8	65.6	59.6	61.4
2036	72.6	66.0	59.6	61.7
2037	73.2	66.4	59.7	62.1
2038	74.1	66.8	59.8	62.4
2039	74.8	67.2	59.9	62.8
2040	75.5	67.7	60.2	63.3

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