DEPARTMENT OF ELECTRONIC & ELECTRICAL ENGINEERING

University of Strathclyde Engineering

The impact of introducing zonal pricing within GB on investment signals to low carbon generation

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A thesis presented in fulfilment of the requirements for the degree of Doctor of Philosophy

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2019

This thesis is the result of the author's original research. It has been composed by the author and has not been previously submitted for examination which has led to the award of a degree.

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September 2019

Abstract

This work has investigated the premise that utilising zonal pricing for congestion management within Great Britain (GB) with Scotland as a separate price zone than the rest of GB could disincentivise investment in wind generation within areas of the highest wind resource. Computational modelling has shown consistently less installed wind capacity in Scotland in scenarios representing zonal pricing compared with scenarios representing the current GB system. This suggests that in the long term implementing zonal pricing within GB could negatively impact on the investment of low carbon generation in locations with the best renewable resource, which would be the most cost-effective method of meeting carbon reduction targets under the UK Levy Control Framework.

The interaction between investing in low carbon generation within multiple price zones and the subsidy framework including a feed-in tariff with Contracts for Difference (CfDs) is a key focus of this work. Multiple scenarios are developed following a discussion of form that the CfD scheme could take in a two-zone GB. These comprise of a base case scenario representing current electricity trading within GB, a scenario in which the current competitive auction system does not change and CfD strike prices remain GB-wide and a scenario in which locational strike prices are introduced.

Computational modelling has taken the form of a two-node linear solver to introduce and discuss the potential impacts of two price zones in GB on investment in low carbon generation and the Scottish Electricity Dispatch Model (SEDM), an eighteen node investment and dispatch model with greater spatial and temporal complexity and thus a more accurate representation of the GB system. The modelling methodology includes representing a range of objective functions, which has been shown to significantly affect the zonal results. Cases have also been revealed in which the SRMC iteration process did not converge for the two zone solver, highlighting the potential issues involved with modelling a subsidy framework like the CfD mechanism within multiple price zones.

Acknowledgements

I would like to acknowledge and thank Keith Bell, Graeme Hawker and Simon Gill for their supervision, advice and help throughout this project. Their knowledge and guidance were indispensable to this work.

Also many thanks to Mike King, Alan Ferrier and the OCEA team at the Scottish Government for access to the SEDM model, as well as the opportunity for a three month placement updating the input data to SEDM. Mike in particular provided a lot of help and advice with the SEDM model and results. Dan Eager from EMRC was also particularly patient in answering my many questions relating to the SEDM.

I would like to gratefully acknowledge financial support from the Engineering and Physical Sciences Research Council through the Centre for Doctoral Training in Wind Energy Systems under grant number EP/G037728/1. I especially appreciated the opportunity to work within the Centre for Doctoral Training in Wind Energy Systems at the University of Strathclyde, led by Bill Leithead, David Infield, Alistair McDonald and Drew Smith. The supportive and friendly working environment alongside several cohorts of other PhD students was an incredible experience and has resulted in many lifelong friendships. Additional thanks to all of the CDT students for the late night writing pizza sessions and many Friday night pints at the Ark.

Finally, this work would not have been possible without the support of many friends and family, too numerous to mention here. Particular thanks to my parents for their many forms of support throughout the years and to Ken for being there every step of the way.

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Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
AD	Anaerobic Digestion
BEIS	department for Business, Energy and Industrial Strategy
BETTA	British Electricity Trading and Transmission Arrangements
BS	Baltic States
CACM	Capacity Allocation and Congestion Management guideline
CAPEX	Capital Expenditure
CCGT	Closed Cycle Gas Turbine
CCS	Carbon Capture and Storage
CEE	Central-East Europe
CET	Central European Time
CfDs	Contracts for Difference
CHP	Combined Heat and Power
CMA	Competition and Markets Authority
CPF	Carbon Price Floor
CSE	Central South Europe
CWE	Central West Europe
DECC	Department of Energy and Climate Change
DSM	Demand Side Managment
EC	European Commission
EMR	Electricity Market Reform
EMCC	European Market Coupling Company
ENTSO-E	European Network of Transmission System Operators for Electricity
EPS	Emissions Performance Standard
ERGEG	European Regulators Group for Electricity and Gas
ERI	Electricity Regional Initiatives
EU	European Union

EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
EWEA	European Wind Energy Association
FES	Future Energy Scenarios
FiTs	Feed-in-Tariffs
FTA	Future Trading Arrangements
FUI	France UK Ireland
GB	Great Britain
GCT	Gate Closure Time
GW	Giga Watt
HVDC	High Voltage Direct Current
LCF	Levy Control Framework
LMP	Locational Marginal Price
LOLE	Loss of Load Expectation
LRMC	Long Run Marginal Cost
MRC	Multi-Region Coupling Project
$MtCO_2$	Megatonne Carbon Dioxide
MW	Mega Watt
MWh	Mega Watt Hour
NE	North Europe
NETA	New Electricity Trading Arrangements
NPV	Net Present Value
NTC	Net Transfer Capacity
NWE	North West Europe
OBR	Office for Budget Responsibility
O&M	Operation and Maintenance
PPAs	Power Purchase Agreements
PV	Photovoltaic
REMIT	Regulation on Wholesale Energy Markets Integrity
rGB	Rest of Great Britain

RIPs	Regional Investment Plans
RO	Renewables Obligation
ROCs	Renewables Obligation Certificates
RSCIs	Regional Security Coordination Initiatives
SEDM	Scottish Electricity Dispatch Model
SEEM	Single European Electricity Market
SMP	System Marginal Pricing
SOAF	Scenario Outlook and Adequacy Forecast
SRMC	Short Run Marginal Cost
SWE	South-West Europe
TNUoS	Transmission Network Use of System
TPA	Third Party Access
TWh	Terra Watt Hour
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
UK	United Kingdom
XBID	Cross-Border Intra-Day

Notation

Two-node solver:

Symbol	Definition	Units
$AnnAmort$	Annuity factor for amortization time	-
$AnnM_y$	Annuity factor for model lifetime	-
$amort$	Amortization time	years
b	Subscript denoting demand block	-
$Capex_{g,y}$	Capital cost of each generation type in each year	£/MW
$CC_{g,y.b}$	Carbon costs for each generation type in each year and block	£/MWh
$Dem_{y,b}$	Demand in each year and block	MW
$FC_{g,y,b}$	Fuel costs for each type of generation in each year and demand block	£/MWh
g	Subscript denoting generation type	-
$Gen_{z,g,y,b}$	Dispatched generation of each generator in each zone, year and block	MWh
$LCF_{\lim}$	Levy Control Framework budget	£
$LCGen_{g,y,b}$	Low carbon generation from each type of generation in each year and block	MWh
$LCGT$	Low carbon generation target	MWh
MCF_g	Maximum capacity factor for each type of generation	-
N_b	Number of demand blocks	-
N_g	Number of types of generation	-
$NIC_{g,y}$	New installed capacity of each type of generation in each year	MW
N_y	Number of years	-
N_z	Number of zones	-
$Omfix_g$	Operation and maintenance fixed cost for each generation type	£/MW

$Om\,\mathrm{var}_{g,b}$	Operation and maintenance variable cost for each type of generation in each demand block	£/MWh
$PTC_{y,b}$	Transfer capacity limit in each year and block	MW
r	Discount rate	-
$\mathrm{Re}\,v_{z,y,b}$	Market revenues	£/MWh
$SRC_{z,g,y,b_{\#}}$	Short run cost of each type of generation in each zone, year and specified block	£/MWh
$SRMC_{z,y}$	Short-run marginal cost in each zone and year	£/MWh
$StrikeP_g$	Strike price for each type of generation	£/MWh
$Subs_{z,g,y,b}$	CfD subsidy (top-up payment)	£/MWh
t_b	Time period of each block	hours
$TCapex_g$	Total capital expenditure for each type of generation before annuity factor adjustment	£/MWh
$TIC_{g,y}$	Total installed capacity of each type of generation in each year	MW
y	Subscript denoting year	-
$yrem$	Remaining model lifetime	years
z	Subscript denoting zone	-

SEDM:

Symbol	**Definition**	**Units**
$AF_{g,b}$	Maximum availability factor	p.u.
$AF\,\mathrm{min}_{g,b}$	Minimum availability factor	p.u.
$Amort_g$	amortization time	years
$AnnLife_g$	annuity factor of economic lifetime	-
$AnnRem_{g,p}$	annuity factor of the remaining generation period	-
$CAPEX_g$	capital expenditure	£/MW
CF	fixed costs	£/MW
$Const_g$	construction time	years
CV	variable costs	£/MWh

d	demand	-
$dem_{d,i,b}$	demand at node i	MW
$\overline{dem}_{a,p}$	peak demand	MW
Dur_{b}	duration of block	hours
e	stage	-
$EMax_{tech,p}$	Maximum annual power generation of technology type *tech*	MWh
$EMin_{tech,p}$	Minimum annual power generation of technology type *tech*	MWh
$emi_{t,po,b}$	emissions	tonnes
$EmiCost_{z,po,e}$	emissions cost	£/tonne
$EnPay_{g,p}$	subsidy payment	£/MWh
$ens_{d,i,b}$	non-supplied energy in node i	MWh
$exists_{g,e}$	existing installed capacity	MW
f	fuel type	-
$f_{j,i,l,b}$	power flow from node j to node i	MW
$f\max_{i,j,l}$	maximum flow for line l	
$fuel_{g,f,b}$	fuel consumption	Fuel unit/MWh
$FuelCost_{f,e}$	fuel cost	£/fuelunit
g	generation unit	-
$gp_{g,b}$	pump storage consumption	MW
$gt_{g,b}$	generation	MWh
$g\max_{g,e}$	installed capacity	MW
$GMax_{tech,p}$	maximum installed capacity of technology type *tech*	MW
$GMin_{tech,p}$	minimum installed capacity of technology type *tech*	MW
IC	total investment costs	£/MW
$Int_{g,r}$	interest accumulated	£/MW

$inv_{g,p}$	volume of investment	MW
l	transmission	-
$MaxExp_{a,p}$	maximum capacity expansion	MW
$MaxInv_{a,p}$	Maximum investment	£
$OMfix_{g}$	operation and maintenance costs	£/MW
p	period	-
po	pollutant type	-
r	discount rate	-
$Rem_{g,p}$	remaining years of generator operation	years
$SRMC_{p}$	short-run marginal cost	£/MWh
$StrikeP_{g}$	generator specific strike price	£/MWh
$tech$	generation technology type	-
$VarO\&M_{g}$	variable operation and maintenance costs	£
z	zone	-
μ_{g}	peak contribution of generator g	p.u.
$\varepsilon_{a,p}$	security reserve factor	p.u.

Chapter 1.

Introduction

1.1. Background

The drive towards decarbonisation in Europe has resulted in various policies designed to encourage investment in low carbon generation. The European Commission's 2009 Renewable Energy Directive set a 20% renewable energy target for Europe by 2020, and included individual targets for each member state [1]. Targets were also set for a 20% cut in greenhouse gas emissions from 1990 levels and a 20% improvement in energy efficiency in Europe by 2020. To meet the 2020 renewable energy target, the United Kingdom (UK) was assigned a target of 15% of gross final energy consumption from renewable sources by 2020, from a start point of 1.3% in 2005 [1]. It was suggested that the majority of this target would come from the decarbonisation of electricity generation, rather than the heat and transport sectors, due to the development already having taken place in this sector and the heavy reliance of fossil fuels for heat and transport [2].

The British government has been encouraging low carbon generation financially to some extent since market liberalisation in the 1990s. The Non-Fossil Fuel Obligation (NFFO) in 1989 and then the Renewables Obligation (RO) in 2002 meant suppliers were obliged to trade a percentage of their supply from renewable sources. The Renewables Obligation involved suppliers and generators trading in Renewables Obligation Certificates (ROCs), earned by generators for renewable generation output. Suppliers without enough ROCs to make up their obligation had to pay a buy-out at a ROC price set by the government [3]. In 2013 the Energy Act replaced the RO with Electricity Market Reform (EMR) [4]. The purpose of EMR was to develop market mechanisms to support low-carbon technologies until they became cost competitive with other forms of electricity generation, while ensuring security of supply and keeping consumer costs at a minimum [3]. In the following years ROCs were replaced by the Feed-in Tariff with Contracts for Difference (CfD) scheme as the market mechanism for low-carbon electricity generation subsidies [5]. The CfD scheme involves an agreed strike price per MWh of generation, and an entitlement to a top-up payment meeting the difference between the strike price and the wholesale price of electricity. The Levy Control Framework (LCF) budget limits the available spend on top-up payments, ROCs and small-scale feed-in tariffs [6]. EMR also introduced a capacity market in GB to ensure security of supply and provide incentives to schedulable generation, a Carbon Price Floor (CPF), which sets a tax on carbon emissions, and the Emissions Performance Standard (EPS), which limits emissions produced by power stations. These schemes are described in further detail in section 2.1.3.

Meanwhile in Europe a series of directives [7]–[9] were passed from 1996-2009 to liberalise European markets and converge wholesale electricity market operation in member states, with the purpose of enabling more straightforward cross-border trading and increased liquidity in markets, driving down prices to consumers within the European Union (EU). Considerable progress towards a single European electricity market (SEEM) has since been made, from the largely insular state-run monopolies of the 1990s to the establishment of day-ahead market coupling of many European power markets in 2014.

In principle, increased cross-border trading within Europe enables the most efficient use of renewable resources, ensuring security of supply through cross-border trades and assisting member states with decarbonisation targets,. In recent years the electricity generation mix has been changing to meet EU targets for renewable energy and carbon reduction, resulting in much higher proportions of renewable generation. Renewable generation in Europe reached 16.7% in 2016, on track with the 2020 target trajectory in the Renewable Energy Directive [10]. Wind energy generation has increased in particular due to the high available wind resource in Europe and competitive lifetime costs compared with other less established renewable sources of electricity. Offshore wind had an annual growth rate of 29% from 2005-2014 in Europe [10].

This work discusses the impacts that the operation of the SEEM could have on investment in generation within Great Britain (GB). As a mainly bilateral electricity market, GB market participants could be impacted by the focus on power exchange trading in the SEEM network codes. The target model for the SEEM has a requirement for zonal pricing to be used for congestion management, which involves market splitting at times of congestion between zones. When the market splits, each zone clears at a separate market price, reflecting the available generation whilst taking account of transmission constraints. This particular requirement could impact on market operation within GB in the case that GB forms more than a single zone. GB currently participates in the SEEM as a single bidding zone, with Northern Ireland part of the Irish bidding zone. The Capacity Allocation and Congestion Management (CACM) guideline currently states that the efficiency of bidding zones should be reviewed every two years [11]. This process of bidding zone review has already resulted in the split of the German-Austrian zone into two separate zones [12], with further reviews looking into internal congestion in France and Poland [13]. There have also been suggestions that Germany should further separate into two bidding zones due to congestion occurring between the high-wind north and solar-rich south [14]. One of the most congested areas on the GB network historically has been at the border between Scotland and England, and increasing renewable capacity in addition to thermal plant closures could result in more congestion occurring at this border. It is not unreasonable to assume that at some point Scotland may be considered appropriate as a separate bidding zone.

This work models all of the major forms of electricity generation in GB, and focuses on wind energy in Scotland in particular. Various factors impact on the attractiveness of investment in generation capacity, including planning requirements, supply chain availability, the operation of the power system, cost of connection to the transmission network, the electricity trading arrangements, potential revenues and profits, lifetime costs (levelised costs), the state of the energy market in terms of price and liquidity and investment signals such as government incentives for various generation technologies (e.g CfDs). Investment in wind energy in Scotland is impacted by all of these factors, of which the most influential in recent years has been the comparatively high wind resource, especially in upland and offshore areas, the planning process and the government incentives available. The Scottish Government is focusing on renewable energy as a key area for economic development, with devolved powers include granting planning permission for generation. It has set an ambitious target of 100% of Scottish electrical demand to be generated by renewables by 2020, as part of a wider electricity mix [15]. In 2015, renewables made up 59.4% of gross electricity consumption [16]. With the highest wind resource in Europe [16], wind generation in Scotland could be vital to meeting the UK's renewable generation and carbon reduction targets.

1.2. Thesis premise and research question

The premise of this thesis is that introducing zonal pricing to Britain with Scotland as a separate zone from the rest of GB (rGB) could negatively impact on the investment in wind generation, compared with treating GB as a single zone. This is due to the potential interaction between zonal pricing and the CfD mechanism impacting upon EMR's main aim: to meet the UK's carbon reduction targets at the lowest possible cost. This possible interaction would depend on the form that the CfD mechanism could take if zonal pricing were introduced to GB. The following paragraphs discuss the reasoning behind this premise in further detail.

With much of the conventional thermal and nuclear generation decommissioning in the next decade in Scotland and a further growth of renewables, it is conceivable that the boundary between Scotland and the rest of GB (rGB) will have a greater frequency of transmission constraints both in import and export, depending on the weather conditions for renewable generation. At times of high wind resource, the maximum export constraint could be reached and wind generation would have to be curtailed, and at times of low wind resource the maximum import constraint could be reached as power is imported from the rest of GB to meet Scottish demand. In a two-zone system this congestion would result in increasing occurrences of market splitting, with a lower price in Scotland when exporting to rGB due to the low operational costs of renewable generation. Investing in generation capacity in Scotland separated by an export and price constraint from the greater part of the load in rGB could result in decreased revenues for investors in Scottish generation. This price difference would mainly affect conventional generation, as low carbon generation in GB with a CfD is guaranteed the agreed strike price by a top-up payment from a reference price, representing the wholesale price of electricity. Currently this reference price is the hourly day-ahead GB zone price for intermittent generation and a seasonal price calculated bi-annually for baseload generation as detailed in the CfD standard terms and conditions [17]. In the case of market splitting this GB zone price will not represent the wholesale price of electricity in either zone, as zonal prices in Scotland will likely be lower than those in rGB, with the low operational costs of renewable energy. As such, it is likely that the two following options will have to be introduced:

1. Separate zonal reference prices at times of market splitting for calculating top-up payments in Scotland and the rest of GB, to represent the different zonal prices occurring.
2. Lower zonal strike prices for Scottish generators, to ensure top-up payments from lower market prices do not use up the LCF budget faster than predicted. This would also maintain the price signals to generation from zonal pricing.

In the case of (1) it is understandable that CfD payments would instead be based on a zonal reference price at times of market splitting, to allow investors to receive the correct top-up payments to their agreed strike price. With lower wholesale prices occurring in Scotland, top-up payments for renewable generation to a GB-wide strike price would be higher and so the LCF budget would be used up faster. This would mean that fewer CfDs would be available to new generation projects, decreasing the likelihood of investments in wind energy (and other low carbon generation funded by CfDs) throughout GB. Scottish low carbon generation in particular would conceivably use up the LCF budget faster, and so would not be a good choice for a government wishing to invest in as much low carbon generation as possible at lowest overall cost.

In the case of (2) the introduction of lower strike prices in Scotland to new generation bidding for CfDs would compensate for the lower reference prices resulting in higher top-up payments and using up the LCF budget. Strike prices are currently granted generator-by-generator in a competitive auction, and it could be that Scottish projects are only considered competitive with similar uplift to projects in rGB if the total top-up liabilities are similar, meaning that they should submit lower strike price offers. In this case all generation would cost the same amount to the government within the LCF, but generators in Scotland would receive less revenue overall, which would disincentivise low carbon development in the Scottish zone. This could potentially lead to the under-utilisation of the favourable wind resources and planning regime in Scotland compared with England or Wales.

The key objectives of this work are:

- To accurately model a representation of the GB power system with Scotland as a separate price zone. This will be done using two different methods: (1) A simple linear solver developed to describe and explore the potential zonal pricing scenarios before introducing the problem in more complex modelling software, namely: (2) The Scottish Electricity Dispatch Model (SEDM), owned by the Scottish Government and adapted for the purposes of this work.
- To use both models to explore the following zonal pricing scenarios:
    - The impacts on investment in generation, CfD payments, carbon emissions and the LCF budget of having two price zones with separate CfD reference prices but with no zonal distinction in respect of low carbon generation strike price; and
    - The further impact of using a zonal strike price for CfD top-up payments on investment in generation, CfD payments, carbon emissions and the LCF budget.
- To conduct appropriate sensitivity analyses, including the impact of the LCF budget with and without 20% headroom and the impact of the addition transmission capacity provided by the Western HVDC Link between Scotland and rGB on the zonal pricing results.
- To explore the differences in these results when setting up these problems as profit maximisation (with an objective function maximising market revenues and CfD top-up payments to generators) and cost-minimisation (minimising the total spend on generation, including CfD top-up payments), two methods commonly used in investment modelling.

This work aims to begin to fill several gaps found in the literature. Although there are various reports detailing the impacts of a potential split in other European bidding zones [14], [18], [19], very little work has focused on the potential for multiple SEEM bidding zones within GB, with only a brief mention of the impacts that zonal splitting could have in Ofgem's bidding zones literature review [20]. Similarly, although there has been a great deal of discussion about the effectiveness of the bidding zone configuration in Europe [21]–[24], there is very little work on the impacts on the investment in low carbon generation due to the designation of bidding zones. No work has been found describing the impacts of market splitting on a subsidy framework including a contract for difference.

The scope of this work involves a representation of the GB power system, with currently existing interconnectors to Europe and Ireland. New transmission links, such as the Western HVDC Link, will be included as a sensitivity analysis but will not be included in all of the simulations. This work is obviously quite politically sensitive, and has been undertaken whilst several referendums have taken place in Scotland and the UK. In 2016, the UK voted to leave the European Union with a majority of 51.9%, with 48.1% voting to remain. It is unclear how this will impact on the participation of GB in the SEEM. GB is still bound by the Climate Change Act to meet its carbon reduction targets, so this work does not assume any changes to the current mechanisms involved. A further discussion of the limits of the modelling methods and models used can be found in Chapter 5.

1.3. Contributions to knowledge

The main contributions to knowledge provided by the work carried out in this thesis are as follows:

- By means of two different models – one, a simple, linear spreadsheet based solver, the other a complex, professionally developed investment and dispatch model – an investigation into whether the introduction of multiple price zones within GB combined with the use either of a GB-wide CfD strike price or zone-specific strike prices would cause, relative to present day wholesale market arrangements, the following:
    - A given LCF budget to be exhausted more quickly or the cost to consumers of supporting low carbon generation to be reduced
    - A significant change to where low carbon generation, in particular wind farms, would be located within GB
    - A greater or lesser reduction in carbon emissions
- An investigation of the sensitivity of modelling results to different objective functions, using both cost minimisation and profit maximisation model set-ups when representing multiple price zones within GB.
- A comparison of the use of a simple model versus a more complex one with lessons presented for:
    - Representing CfDs using an iterative methodology to ensure model output marginal prices matched input reference prices within the CfD top-up payment calculation.
    - Representing multiple price zones within a model which uses an iterative methodology to calculate CfD top-up payments.
    - The overall design and use of models intended to inform policy decisions.

1.4. Thesis outline

The structure of this thesis is described in the following sentences. Chapter 2 discusses electricity trading and Electricity Market Reform in GB before presenting a brief history of electricity market liberalisation in Europe and the development of the single European electricity market. Chapter 3 compares the various market-based methods of congestion management and describes zonal pricing as the form of congestion management chosen for the SEEM before presenting the thesis premise and reasoning in detail, including a discussion of the forms that CfDs could take in a two-zone GB. Chapter 4 discusses investment modelling methods used in the literature and the modelling framework of this work including a detailed description of a simple illustrative two node solver and the more complex Scottish Electricity Dispatch Model. Chapter 5 details the results from the two node solver, illustrating the potential interaction between zonal pricing and the CfD mechanism using a simple modelling framework. Chapter 6 details zonal pricing results using the SEDM, a professionally developed tool with greater spatial and temporal complexity than the two node solver. Finally, Chapter 7 summarises the results, the key conclusions from this thesis and gives suggestions for further work.

Chapter 2.

Electricity markets in GB and Europe

The following sections give some background behind the sources of revenues and costs for generation projects in GB, including Electricity Market Reform (EMR) and the subsidy mechanism of Feed-in tariffs with Contracts for Difference (CfDs). The development of the single European electricity market (SEEM) is also discussed, including the legislation passed regarding its operation and the current plans for future developments, such as intraday trading.

2.1. Electricity trading in GB

Electricity trading has taken two major forms in the last thirty years of market liberalisation in GB, the mandatory Pool system of the 1990s and then voluntary decentralised trading in the 2000s. The British electricity market was one of the first in Europe to undergo liberalisation, moving from a state-owned monopoly to privatised energy companies in the early 1990s [25]. At this time the goal of liberalisation was to increase competition and efficiency in energy markets.

In the late 1990s the newly-elected Labour Government conducted a series of reviews on the electricity trading arrangements and came to the conclusion that market power was present and causing inefficiencies within the Pool system. The Government replaced the central mandatory Pool with a set of decentralised voluntary wholesale trading mechanisms known as the New Electricity Trading Arrangements (NETA) and the Utilities Act 2000 legally separated generation, transmission, distribution and supply through mandatory separate licencing [26]. In 2005, The British Electricity Trading and Transmission Arrangements (BETTA) were introduced as an extension to NETA to include Scotland, and remain the current form of wholesale electricity trading in GB.

BETTA allows for both bilateral and power-exchange trades, of which long-term bilateral trading is the most common. Trading takes place without consideration of system constraints and so system balancing is performed centrally by the GB Transmission System Operator (TSO), National Grid. Trading under BETTA and the balancing market are described further in section 2.1.1.

The introduction of NETA (and thus BETTA) has been questioned due to its high cost and apparent failure to increase liquidity and demand side trading [27]. While these trading arrangements were specifically introduced to increase competition and reduce energy bills, the GB wholesale market has favoured long term confidential bilateral trading arrangements. As the price point of these bilateral agreements is not publically available it is difficult to judge if drops and rises in wholesale electricity prices are being efficiently passed on through consumer bills [28]. In fact in 2013 Ofgem referred the GB retail market for review to the Competition and Markets Authority. The resultant State of the Market Assessment found retail supply companies profits had been increasing without benefits being passed on to consumers [29].

The suitability of BETTA for the transition to low carbon generation has also been discussed [30]-[31], for example in the House of Commons Energy and Climate Change Committee Electricity Market Reform Fourth Report [31]:

"BETTA was designed to support large, centralised, predictable fossil-fuelled and nuclear generation. This creates difficulties for intermittent electricity sources. For example, the current approach depends on predictable generation capacity which can commit to deliver precise volumes of electricity a year or even more in advance on long-term contracts. Suppliers can fine-tune their portfolio of contracts closer to delivery as actual demand becomes clearer. This may not be suitable for the low-carbon future needed. Wind power may be predictable in the short term and can be forecast accurately a few hours ahead of delivery, but it cannot be guaranteed for a particular half-hour slot in the weeks, months or further ahead."

2.1.1. Factors influencing investment in generation in GB

Various factors impact on the attractiveness of investment in generation capacity, including planning requirements, government incentives, supply chain availability, the operation of the power system, the electricity trading arrangements, the state of the energy market in terms of price and liquidity and additional investment signals such as government incentives for various generation technologies. Developers looking to invest in generation projects look into the predicted balance of lifetime costs and potential revenues and profits when making decisions about projects. The following paragraphs discuss the sources of costs and revenues for generation currently in GB.

Sources of costs for generators in GB can be categorised in two ways: capital costs and operational costs. These costs are technology and plant specific depending on plant location, infrastructure and fuel requirements. Capital costs incurred include construction and infrastructure costs. Operational costs can take the form of fixed costs for each year, including staff costs, maintenance contracts and insurance, or variable costs dependent on plant output, such as fuel and carbon costs (where applicable) and variable repair and maintenance costs [32].

The discounted sum of all capital and operational costs over the generator lifetime per unit of energy produced is known as the levelised cost of generation. The levelised cost of a generator is often used as a metric to compare different projects when considering their investment potential. Generation plant can either be categorised as fuel-intensive (comparatively cheap capital costs compared with expensive fuel costs) such as CCGT or capital-intensive (expensive capital costs and cheaper or free fuel costs) such as wind generation. This is illustrated in Table 1, which shows levelised costs broken down into development, construction and operational costs for a CCGT and onshore wind generator commissioning in the UK in 2020 from the Department of Business, Energy and Industrial Strategy Electricity Generation Costs report 2016 [33]. It can be seen that construction and fixed O&M costs are much higher for onshore wind and fuel and carbon costs are much higher for CCGT. Both of these types of plant have different drivers in minimising the overall levelised cost, for fuel-intensive plant maximising fuel efficiency and minimising fuel and carbon costs are a priority, for capital-intensive plant the priorities are minimising development, construction and CAPEX costs and maximising generator output [32].

Table 1 – Costs for a CCGT and onshore wind generator commissioning in 2020, from BEIS Electricity Generation Costs Report 2016 p25 [33]

Cost (£/MWh)	CCGT (H Class)	Onshore wind (>5MW)
Pre-development	0	4
Construction	7	44
Fixed O&M	2	10
Variable O&M	3	5
Fuel Costs	35	0
Carbon Costs	19	0
Levelised cost	**66**	**63**

Carbon costs in GB are set by the Carbon Price Floor (CPF), which ensures that generators have to acquire permits for a set price per tonne of CO_2 produced. The CPF was introduced in 2013 in addition to the EU Emissions Trading System (ETS) with the goal of pricing carbon emissions at a level that allows low carbon technologies to compete with traditional thermal generation. It was felt that the ETS was not incentivising low carbon technology as its design intended, with carbon certificate prices falling from €30 per tonne of CO_2 in 2005 to near zero in 2007 as the number of contracts available was greater than the emissions produced [34]. The EU ETS market price has remained at around €5/t CO_2 from 2012-2016 [35]. The CPF started at £9.55/tCO_2 in 2014, rising to £18/tCO_2 in 2016 and capped at this value until 2021 [36].

Another cost not covered in the BEIS figures above is the Transmission Network Use of System (TNUoS) charges to generation. These cover the transmission owners costs incurred for the operation, maintenance and development of the transmission network infrastructure. TNUoS charging in GB has been updated in recent years to provide a locational signal based on the type of generation, the five year average load factor of the generator and the region in which it is located [37]. GB is split geographicaly into 27 regions, and generation is split into two categories, conventional (e.g. gas, nuclear, hydro) and intermittent (e.g. wind). National Grid model power flows at system peak and year round and set four tariff elements: a year round shared element (weighted by load factor), a year round not shared element, a system peak security element (only payable by conventional generation) and a residual element. The sum of these elements gives the overall tariff for each generator. Table 2 below shows TNUoS elements and example tariffs in 2016-17 for a conventional generator with a 70% load factor and an intermittent generator with a 30% load factor in the most expensive (Argyll) and cheapest (Central London) zones in GB [38]. Generators pay a larger tariff in zones more likely to experience congestion and as such generation has an incentive to build in zones with cheaper tariffs. However, TNUoS also represents a certain amount of uncertainty to generation, as charges can change from year to year depending on the generation in the region.

Table 2 – TNUoS tariffs for Argyll and Central London zones in 2016-17, from reference [38]

Zone	System peak element (£/kW)	Shared Year Road element (£/kW)	Not shared Year round element (£/kW)	Residual element (£/kW)	Conventional gen tariff (70% load factor) (£/kW)	Intermittent gen tariff (30% load factor) (£/kW)
7 - Argyll	-0.47	5.34	15.89	0.51	19.66	18.00
23 - Central London	-2.76	3.11	-6.32	0.51	-6.40	-4.88

There are various sources of revenue for generators in GB. Wholesale trading makes up a large part of a generator's earnings, but generators can also gain revenues through balancing markets, reserves contracts, capacity markets and providing ancillary services. Currently wholesale electricity trading in GB is mainly conducted in long term bilateral trades, relying on power purchase agreements (PPAs). Data from Ofgem, the regulator for gas and electricity markets in GB, shows 86.5% of electricity trading volumes were from bilateral trading in 2016 [39]. Figure 1 illustrates the wholesale electricity trading volumes from 2010 to 2016, from the main power exchanges (N2EX, APX and ICE) and also from over the counter (OTC) bilateral trading. It can be seen that bilateral trades dominate, but the proportion of trading has increased from power exchanges, particularly N2EX, from 2012 onwards. In this year, two of the ‘big six’ electricity suppliers in GB made commitments to trade more of their generation and demand on the day ahead market, with SSE “*trading 100% of daily generation and demand*” [40] and EDF pledging “*more than 30% of its generated volume*” [41]. This was in response to pressure from Ofgem after its Retail Market Review in 2011 concluded that market liquidity was a problem in GB [42].

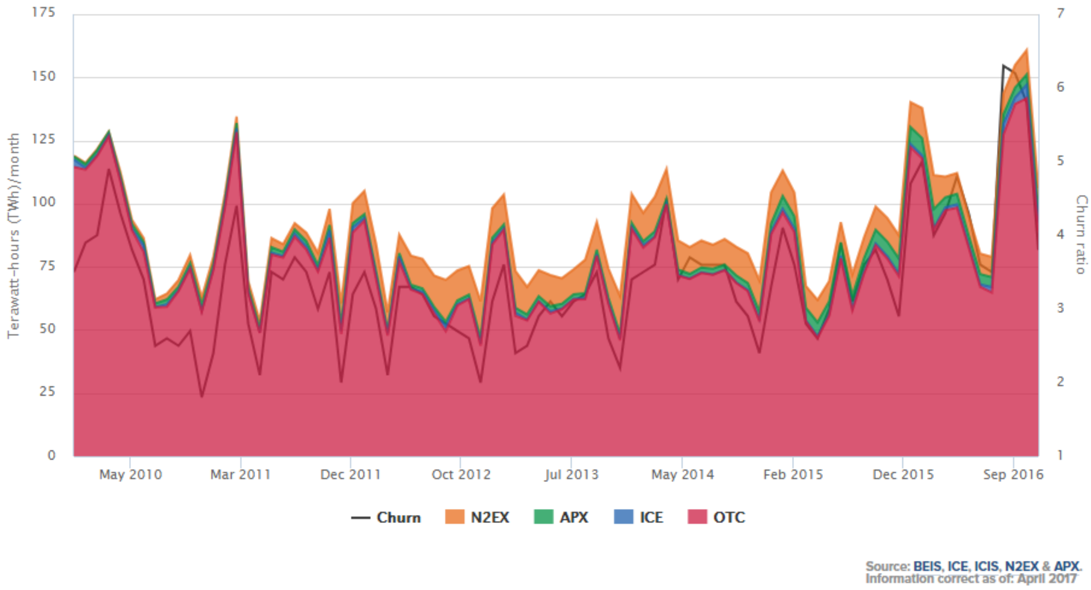


Figure 1 - Electricity trading volumes and churn ratio of N2EX, APX and ICE power exchanges and from OTC trades from 2010-2016, from reference [39]

The APX and N2EX power exchanges are the Nominated Electricity Market Operators (NEMOs) for day ahead and intraday coupling between mainland Europe and GB [43]. Due to the requirements of European market coupling when the North West Europe (NWE) region coupled in February 2014, these power exchanges became a ‘GB virtual hub’ by connecting day-ahead auctions in both exchanges with a ‘virtual interconnector’ of infinite transfer capacity. This ensures a single day-ahead hourly price for normal operation and, according to [44], guarantees that day-ahead trades over interconnectors to GB are optimal in both markets.

Balancing markets are used by the system operator to balance demand and generation with respect to system constraints once wholesale trading has taken place. Producers and suppliers have to declare their final physical positions at gate closure, one hour ahead of delivery. After gate closure the balancing market takes place, meeting redispatch requirements over half-hourly settlement periods by contracting generators and large consumers to change their expected physical output based on bids to reduce generation/increase demand and offers to increase generation/reduce demand. The cost of this mechanism is socialised to all generators and suppliers using a Balancing Services Use of System (BSUoS) charge with no locational element. Imbalances between declared and actual physical positions at time of delivery are dealt with by charging a system buy price to generators under generating/suppliers over consuming and paying a system sell price to generators over generating/suppliers under consuming [45]. There is a single price calculation, meaning that the system buy and sell prices are identical for each settlement period[46].

Additional sources of revenue include ancillary services, reserves markets, generator subsidies and the capacity market. Ancillary services include reactive power, frequency response and black start-up. Reserves are contracted by National Grid based on predicted security margins and reserves markets take the forms of monthly procurement of fast-reserve, tri-yearly procurement of short-term operating reserve, and an annual contingency reserve for times of winter peak demand [47]. Subsidies to low carbon generation and the capacity market are discussed further in section 2.1.3.

2.1.2. Carbon reduction targets and impacts on electricity trading

In a liberalised market, incentives are required to reduce emissions from electricity production and encourage renewable generation if carbon reduction targets are to be met. Market players need to make profit to continue operating, and historically traditional thermal generation projects have been cheaper investments and produced more profit than renewable generation projects. In addition to this, thermal generators can be situated close to load and provide more control over dispatch than intermittent renewable generation, which produces output dependant on geographical location and weather conditions. To encourage initial investment in low carbon generation, it must be made cost competitive with other generation. This can be done through subsidising low carbon generators to increase their revenue stream, or by taxing carbon producing generators to increase their costs based on emissions. Such incentives can take the form of tender schemes, feed-in tariffs (FITs), tax credits, national quotas and certificate schemes. FITs tend to be the most common incentive provided, especially for renewable and low-carbon generation, and have been described as the most effective of these schemes in encouraging wind generation [48]. However, it is also true that FIT payments separate renewable generation from market signals, and indeed can result in market distortions such as negative prices, due to renewable generation with low variable costs and guaranteed subsidy payments. To this end, it has been argued that capacity-based support mechanisms could provide incentives to low carbon generation whilst avoiding market distortions by decoupling subsidy payments with energy output [49].

In GB, support schemes for emissions reduction began in 1989 when the Non-Fossil Fuel Obligation (NFFO) was introduced along with the Electricity Act. Intended to support renewable generation, contracts were offered to renewable generation developers and electricity suppliers were obliged to buy generation from renewable generators at the contracted price. However a high amount of renewable projects granted contracts were not developed and the NFFO had very little effect on incentivising renewable generation [50].

With the signing of the Kyoto agreement in 1997 setting carbon reduction targets for 2012, new incentives for carbon reduction were required in GB. In 2002, the Renewables Obligation (RO) replaced the NFFO. Under the RO, suppliers were obligated to have a proportion of their supply from low carbon sources. Generators in the scheme received Renewables Obligation Certificates (ROCs) based on their MWh generation output, which could then be sold to suppliers or traders. Suppliers who did not meet their obligation would have to pay a ‘buyout price’. In 2009 banded ROCs were introduced to encourage less established technologies such as wave, tidal and offshore wind generation. The RO proved much more effective in encouraging development in renewable generation than the NFFO, with the 19.1% of electricity generated from renewable sources in 2014 [51] compared with 2% prior to the scheme [52].

The RO, though effective in encouraging investment in low carbon technologies, was expensive and costs were passed on to consumers [53]. In 2008 the Climate Change Act introduced a legally binding target to the UK of an 80% reduction of greenhouse gases from 1990 levels by 2050, and the European Renewable Energy Directive 2009 set a European target 20% of generation from renewable sources by 2020, with a UK specific target of 15%. European targets are a 20% reduction of emissions from 1990 levels and a 20% reduction of demand by 2020. The need to develop a more cost effective solution to meet these targets resulted in the development of Electricity Market Reform (EMR).

2.1.3. Electricity Market Reform

Electricity market reform (EMR) was introduced through the Energy Act 2013 [4], with the purpose of developing a market mechanism to establish an electricity system in which low-carbon technologies can compete, whilst ensuring security of supply and keeping costs to the consumer at a minimum [3]. Under EMR, two new market mechanisms were introduced: Feed in Tariffs with Contracts for Difference (CfDs) and the Capacity Market. These are also supported by The Carbon Price Floor (CPF), which sets an increasing yearly tax on carbon emissions, and the Emissions Performance Standard (EPS), which limits emissions produced by power stations. National Grid was appointed as the delivery body for EMR, and a private company was set up as the CfD counterparty [54].

The Renewables Obligation was gradually phased out until 2017 with generators having the choice to apply for either CfDs or the RO until then, with the exception of onshore wind which was removed from the RO in 2016 when the UK government ended all subsidies for onshore wind [55]. After 2017, the RO has been vintaged and those party to the RO will continue to receive payment for the length of their 20 year contracts. The RO continues to be funded by the supplier obligation as part of the Levy Control Framework, along with CfDs, small scale FiTs and the warm home discount [56].

2.1.3.1. Contracts for Difference

The new system of CfDs was introduced to replace the previous RO scheme, with the idea that a guaranteed revenue would ensure greater certainty to investors by reducing price risk. CfDs offer a feed in tariff to low carbon generation at a set strike price in pounds per MWh, decided on a project-by-project basis by an auction process and intended to cover generation lifetime costs. CfD strike prices do not represent levelised costs as the contract length of 15 years does not represent the generator lifetime. To enable a reliable route to market, generation granted CfDs are also guaranteed Power Purchase Agreements (PPAs) and thus a set minimum revenue due to the Backstop PPA mechanism [57].

The CfD mechanism is illustrated in Figure 2. When the reference price, representing market revenues, is lower than the strike price generators will receive a top-up payment making up the difference, and when the reference price is greater than the strike price generators will have to pay back the difference. The maximum strike prices set by the Department of Energy and Climate Change (DECC) were originally around £95/MWh for onshore wind and £155/MWh for offshore wind in the first CfD auction in 2015 [3] .

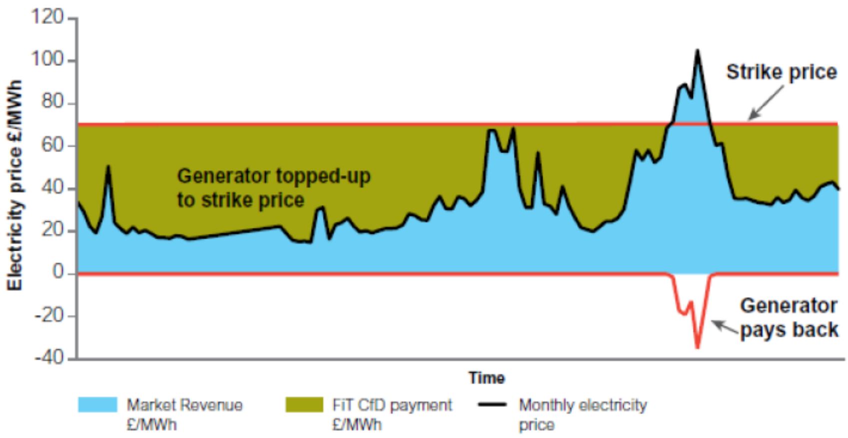


Figure 2 - Illustration of CfD mechanism, from reference [3]

Using the correct reference price is vital for ensuring CfD scheme generators gain a realiable income. The reference prices used to calculate CfD top-up payments differ depending on whether the generator is classified as ‘baseload’ or ‘intermittent’. Table 3 below lists the CfD technologies assigned to either category. The intermittent reference price is calculated using day-ahead hourly market data from the APX-UK and N2Ex power exchanges, pooled together to form a GB Zone Price [17]. Much of baseload is traded at longer timescales in the forward markets, so day-ahead reference prices do not represent their revenues. Consultations with industry suggested that annual baseload forward prices are not yet liquid enough to give a representative annual price, so currently the baseload reference price is calculated bi-annually until a time at which market liquidity has sufficiently improved [58]. More details on the calculation of intermittent and baseload reference prices can be found in the CfD Standard Terms and Conditions [17].

Table 3 - Technologies to be assigned baseload and intermittent reference prices. From reference [59]

Technologies to receive the baseload reference price	Technologies to receive the intermittent reference price
Advanced conversion technologies[1]	Offshore wind
Anaerobic Digestion	Onshore wind
Carbon Capture and Storage	Solar PV
Dedicated biomass with CHP	Tidal range
Biomass conversion	Tidal stream
Landfill gas	Wave
Sewage gas	
Qualifying waste with CHP	
Geothermal	
Hydroelectric	
Nuclear	

CfDs are funded by the Supplier Obligation (SO), which passes on costs incurred to suppliers based on their share of the supply [54]. A counterparty has been created to manage payments between generators and suppliers and manage financial risk in case of payment default [3]. Funding for CfDs is limited by the Levy Control Framework (LCF), which sets a limit to the total public spending passed on through consumer bills for CfDs, the RO, small-scale feed-in-tariffs and the warm home discount of £7.6 billion (in 2012 prices) by 2020 [6]. It requires the Department for Energy and Climate Change (DECC), now the Department for Business, Energy and Industrial Strategy (BEIS), to take 'early action' if LCF spend forecast is above the budget, and 'urgent action' if this forecast is in excess greater than 20% of the budget. This 20% headroom has been introduced to cover over spend in top-up payments due to the uncertainties involved in predicting future wholesale prices [60].

CfD contracts are for 15 years, with applications for CfDs for projects over 300MW requiring an additional supply chain plan. In an effort to minimise the disruption to low carbon generation

[1] E.g. gasification and pyrolysis as treatments for residual waste

projects during the transition to CfDs, DECC allowed several CfD contracts to be awarded early at strike price cap levels, known as the Final Investment Decision enabling for Renewables (FIDeR). Eight projects were granted these early CfDs in April 2014, consisting of five offshore wind farms and three biomass projects. The combined capacity of these projects was 4.54GW [61]. This move has been criticised as being too generous an investment to these projects and unnecessarily using up too much of the LCF budget, as the strike price cap levels are much higher than the resultant strike prices from the competitive auction the following year [61].

The first competitive auction for CfDs occurred in 2015. Technologies were split into two brackets of ‘established’ (e.g. onshore wind and solar) and ‘emerging’ (e.g. offshore wind and marine technologies), each with their own budget allocated, totalling a £300million budget overall for the total top-up. Twenty-seven projects were granted contracts: three advanced conversion technologies projects, two energy from waste, two offshore wind, fifteen onshore wind and five solar PV [62]. These auction results are summarised by technology type with total capacity and strike price for each given year of entry in 2012 prices in Table 4. However, two of the solar projects entered bids too low to be able to progress and did not go ahead. The next auction was due to take place by the end of 2016, but was pushed back to autumn 2017. The 2017 auction results are summarised in Table 5 in 2012 prices [63]. This auction and the following CfD auctions are only for emerging technologies, such as offshore wind and marine generation, in line with the Conservative Government policy to end subsidies to onshore wind [64].

Table 4 – CfD 2015 auction results summary by technology type and year of entry

Generation Technology	Capacity (MW)	Strike Price (£/MWh)	Year of Entry
Advanced Conversion Technologies	36	119.89	2017-18
	26	114.39	2018-19
Energy from waste with CHP	94.75	80.00	2018-19
Offshore wind	714	119.89	2017-18
	448	114.39	2018-19
Onshore wind	45	79.23	2016-17
	77.5	79.99	2017-18
	588.55	82.50	2018-19
Solar PV	32.88	50.00	2015-16
	38.67	79.23	2016-17

Table 5 – CfD 2017 auction results summary by technology type and year of entry

Generation Technology	Capacity (MW)	Strike Price (£/MWh)	Year of Entry
Advanced Conversion Technologies	56.31	74.75	2021-22
	8	40.00	2022-23
Dedicated Biomass with CHP	85.64	74.75	2021-22
Offshore wind	860	74.75	2021-22
	2336	57.50	2022-23

2.1.3.2. The Capacity Market

The capacity market was introduced as part of EMR in 2014, and is governed by the Electricity Capacity Regulations [65] and the Capacity Market Rules [66]. The purpose of the capacity market is to ensure sufficient dispatchable generation by providing payment for available capacity, to be used in the event of system stress. Pre-qualification for the market occurs to determine eligible generation. Auctions take place four years and one year in advance, based on forecast capacity needed to meet the reliability standard. Fines will be incurred by generation contracted but not delivered, provided a four-hour warning of system stress has occurred. In the event of system stress, expected delivery will be the ratio of demand to the proportion of total capacity auctioned. Capacity mechanisms in various forms are already part of some European markets, such as in Ireland, Greece and France. Countries such as Germany and Poland are also considering introducing capacity markets [67]-[68], although the European Commission is not in favour of individual states establishing independent capacity markets, arguing that they discourage intra-state trading and development of interconnection [69].

Funding for the capacity market is not included in the LCF, but is also passed down to the supplier and thus the consumer through energy bills. The first auction took place in December 2014 for 2018. There was a target capacity of 50.8GW to be auctioned in the T-4 auction, with an additional 2,500MW remaining for the T-1 auction. This is to achieve an overall reliability standard Loss of Load Expectation (LOLE) of 3 hours/year. The auction takes the form of four 1.5 hour rounds with 30 minutes in between for four days, with bids capped at £75/kW/year [70]. T-4 auction results gave a clearing price of £19.40/kW/year in 2014 [71], £18.00/kW/year in 2015 [72] and £22.5/kW/year in 2016 [73]. From 2015, trades over interconnectors were also included in the capacity market T-4 auctions [74].

In January 2016, a transitional T-1 capacity auction took place for winter 2016-17, clearing at £27.5/kW/year [75]. This auction was motivated by the reduction in capacity due to the closure of several coal plants, meaning security margins were tighter than expected. The capacity obligations for this auction became officially active on the 1st October 2016 and the first capacity market notice to generators took place on the 31st October 2016 [76]. A further early T-1 auction occurred in February 2017 for winter 2017-18 with a clearing price of £6.95/kW/year [75].

2.1.3.3. Effectiveness of EMR

The aim of EMR as laid out by the UK Government was to aid low carbon generation to market by providing enough incentives to allow it to compete with traditional thermal generation. This was done by introducing the CfD top-up payments, providing a guaranteed income at a set strike price per MWh of generation and reducing price risk for generators. Meanwhile, the CPF and EPS provide disincentives to heavily carbon producing generation through additional costs, and the Capacity Market provides additional income to dispatchable generators for providing additional generation when margins are tight. It is difficult to judge the effectiveness of EMR at this early stage, with three competitive auctions having occurred for CfDs and the capacity market currently suspended by the European Court of Justice [77].

While EMR has been introduced to offset price risk and enable low carbon generation to compete in energy markets, it does also introduce new risks and sources of uncertainty. The transition to any new scheme involves various uncertainties to generators and developers, such as changes to the application process for new generation and the limited funding available for the scheme. In this case the move from the RO to the CfD scheme involved the introduction of a competitive auction for projects, with funding limited due to the LCF. There is a difference in the length of contract between the RO and CfDs, falling from 20 year RO contracts to 15 year CfDs, which will impact upon investment decisions. Once the FiDer contracts had been awarded various economic projections were suggesting that much of the LCF budget had already been allocated [78]. Many projects rushed to meet RO deadlines before the scheme ended, and a grace period was granted to those falling short. The delays in holding CfD auctions have introduced a further source of uncertainty for the scheme. After the first auction in February 2015, a second was expected later in the year, before being delayed to 2016 and then finally to 2017.

Up until 2015, DECC projections of LCF spend until 2020 were within the £7.6 billion cap. However in June 2015 these projections rose to £9.1 billion, nearly surpassing the 20% permitted headroom. This was due to various factors in their calculations being greater than those forecast, including increased generation from projects already granted feed-in-tariffs and ROCs, additional applications by projects to the RO and FiT schemes and an increase in the forecast top-up payments due to a reduction in fossil fuel (and thus reference) prices [60].

A key uncertainty to project developers is if they will be able to bid competitively enough in the auctions to be granted a CfD within the limited budget remaining. The maximum strike price for CfDs is degressing with time, with the purpose of reflecting decreasing technology costs in the future [79]. The maximum strike price for offshore wind in the 2017 auction was £105/MWh, lowering to £100/MWh by 2020 [80], whereas in 2015 it was £155/MWh [3]. It has been argued that offshore wind will get more expensive as rounding moves further and further offshore [81], so this degression could impact on the investment of offshore wind. BEIS 2016 generation costs report gives levelised cost estimates for round 3 offshore wind projects commissioning in 2020 at £93-£119/MWh [33]. In 2019, following the conclusion of this research, the third CfD auction round saw strike prices for offshore wind and remote island onshore wind projects falling further to as low as £39.65/MWh [82]. It is estimated at this price that the actual monetary budget impact will be zero, effectively making the wind projects subsidy free. This would suggest that EMR has been effective in supporting renewable projects until they become cost competitive with other generation technologies. However, the increasing competitiveness of the CfD auction could make it more difficult to support more expensive projects further offshore once the most cost effective locations have been utilised. Setting a precedent for low levels of support to renewables could also mean that the CfD mechanism is not available for new innovative technologies such as marine energy and CCS, which could also contribute to carbon reduction targets in the long term. The low auction results and lack of ringfencing for marine technologies has meant that they have not yet been successful in gaining a CfD.

Onshore wind has already been phased out of future CfD auctions, as a Conservative Government policy to end subsidies to onshore wind. A Baringa report for Scottish Renewables in 2017 estimated that if 1GW of onshore wind were to be granted a CfD in the next auction, it would have no impact on the LCF budget (i.e pay back would be equal to top-up payments within the generator lifetime) [83]. In addition to this the BEIS generation costs report released in 2016 gives levelised cost estimates ranging from £47/MWh to £76/MWh for onshore wind, and £53/MWh to £76/MWh for CCGT [33]. In this case, the UK Government seems to have completed its target of supporting a low carbon technology until it becomes cost competitive.

Another tool impacting on the generation mix in GB is the European Union Large Combustion Plant Directive 2001 (LCPD, 2001/80/EC) which limited the emissions of large thermal plant built after 1987, and thermal plant built before this date had the option of emissions compliance or an ‘opt-out’ scheme, limiting the plant to a maximum of 20,000 hours of further option before mandatory plant closure by 2015. This act resulted in the closure of much of the coal fleet in GB [84].

Figure 3 shows the generation in GB from 2006 to 2016. It can be seen that coal generation has greatly reduced, particularly from 2014 onwards. Generation from wind, solar and bioenergy has increased in this timeframe, due to incentives such as small scale FiTs and the Renewables Obligation.

The future of EMR is unclear, with the government having already confirmed that the LCF will be replaced by another mechanism after 2020. A ‘stabilising mechanism’ or ‘subsidy-free’ CfD has been discussed as a potential transitionary framework for ‘established’ technologies such as onshore wind, to raise low carbon generator revenues to a point where they can better compete with traditional thermal generation [85].

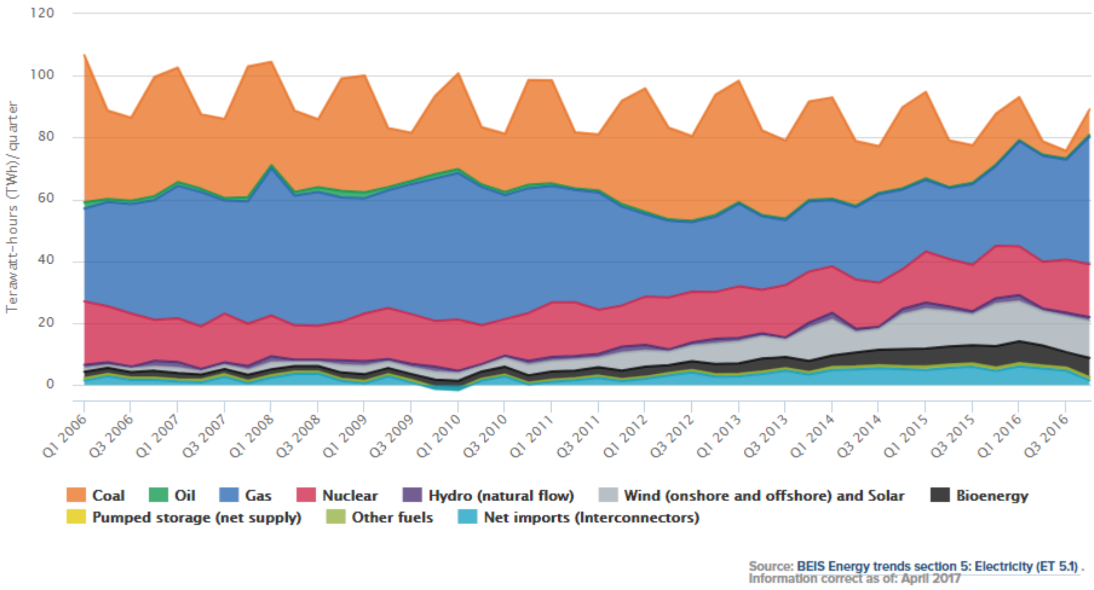


Figure 3 – GB generation mix 2006-2016, from reference [39]

2.2. The European Single Market

Before the 1990s most countries in Europe had monopolistic vertically integrated generation and transmission companies, often state owned. After the formation of the European Union in 1993, many EU policies have been introduced to develop an internal market which ensures the “*free movement of goods, capital, people and services*” [86]. With regards to electricity generation and trading, the European Commission established several electricity directives in an effort to move towards a more competitive market, and also to work towards achieving Europe-wide emissions and renewables targets. Benefits of a single European electricity market (SEEM) were said to include increased access to domestic energy sources, improved security of energy supply, increased penetration of renewables and improved competition, in turn decreasing energy prices [87].

The main objectives for energy policy in Europe, as stated by the European Commission, are as follows:

"energy in the European Union should be affordable and competitively priced, environmentally sustainable and secure for everybody. A well-integrated internal energy market is a fundamental pre-requisite to achieve these objectives in a cost-effective way." [67]

The following sections describe the legislation introduced to liberalise European energy markets and the development of the SEEM, before going on to discuss the effectiveness of the SEEM in meeting these goals.

2.2.1. European legislation

In total there have been three legislative packages of EU electricity directives and regulations concerning the common rules for a single European electricity market. These are shown in Figure 4.

	Publication date	Transposition deadline	Directive /Regulation
First Package	19/Dec/96	19/Feb/99	Directive 96/92EC[17] concerning common rules for the internal market of electricity
Second package	15/Jul/03	01/Apr/04	Directive 2003/54EC[18] concerning common rules for the internal market of electricity
	26/Jun/03	01/Jul/04	Regulation (EC) 1228/2003 on conditions for access to the network for cross-border exchanges of electricity
	9/Nov/06		Commission Decision 2006/770/EC amending the annex ("Congestion Management Guidelines") for regulation 1228/2003
Third package	13/Jul/09	03/Mar/11	Directive 2009/72/EC[19] concerning common rules for the internal market of electricity
			Regulation (EC) 714/2009 on conditions for access to the network for cross-border exchanges of electricity
			Regulation (EC) 713/2009 on establishing an Agency for the Cooperation of Energy Regulators (ACER)

Source: Adapted from REKK & KEMA, EC, DG Energy

Figure 4 - Timeline and details of EU legislative packages concerning the common rules for the internal market of electricity. From reference [88].

In 1996 the first legislative package (Directive 96/92/EC) [7] came into force. Intended to begin to disassemble the system of legal energy monopolies, it included conditions for generation, transmission and distribution in each state to produce separate accounts and for the designation of independent transmission and distribution system operators. It also required member states to choose between authorizing or tendering procedures for a fair selection of new generation construction, opening up generation to competition. Lastly it introduced methods for member states to ensure non-discriminatory access to transmission and distribution networks, with the choice between adopting a third party access (TPA) system or a single buyer system.

The European Commission has since recognised various shortcomings with this directive, including the need for more binding conditions for generation, transmission and distribution to reduce market dominance and encourage competition. They identified the main obstacles for arriving at a competitive and operational electricity market to be lack of open access to the network, transmission and distribution needing to charge fairer tariffs and member states being at different stages in market liberalisation. They also recognised the need for regulatory bodies within the electricity industry [8].

In 2003 the second legislative package (Directive 2003/54/EC) [8] came into place, with the aim of enforcing the legal separation of generation and transmission and thus attempting to unbundle the vertical integration. It included conditions for the designation of transmission and distribution system operators and specified that these must be independent in terms of legal form, organisation and decision making from any vertically integrated organisation. Furthermore it included provisions for all non-residential electricity consumers to have the ability to choose their electricity supplier from 1st July 2004 and all residential consumers from 1st July 2007. It specifies that each state must have a non-discriminatory authorisation process for new generation capacity, with additional tendering processes if required for security of supply. It also required each state to set up a regulatory authority independent from the electricity industry to ensure that the industry was non-discriminative, encouraging competition and functioning efficiently. The regulatory authority was made responsible for regulating methodologies developed by transmission and distribution for network connection, setting tariffs and providing balancing services. It also acts as the settler for disputes arising from any complaints about transmission or distribution activities.

Both the first and second directives set conditions to be met by each state, mainly focusing on the unbundling of vertical integration in the electricity industry to promote competition within each state. However, this left key decisions about market structure and trading to each individual state. The resultant design of electricity markets in member states differed greatly, meaning that merging into a single European electricity market would prove a challenging task.

In 2009 the third legislative package (Directive 2009/72/EC) [9] came into force. The coordination of regulation was a particular focus, as the European Commission had recognised that regulation had previously mainly come from the state governments and lacked independence and sufficient powers. It was decided that regulators should have the power to request relevant information from electricity generation, transmission and distribution undertakings, have power of decision over important issues and be able to penalise undertakings that did not adhere to these decisions appropriately. Two organisations were established, the Agency for Cooperation of Energy Regulators (ACER) and the European Network of Transmission System Operators for Electricity (ENTSO-E) (Regulations 713/2009/EC and 714/2009/EC respectively). ACER was established to provide a framework of cooperation between the various national energy regulators. ENTSO-E was established to represent all of the European transmission system operators and coordinate Europe-wide planning and operations.

The key focus of the third directive was the formation of a single European energy market. The European Commission recognised that the security of supply and levels of competition was still inadequate in most member states, with more market transparency required to encourage new generation. The directive included the provision that common technical rules and safety criteria must be defined to ensure that generation, transmission and distribution systems all adhere to minimum requirements. This was to ease the interconnection process between regional systems. The directive also stated that each member state and the regulatory organisations must be in cooperation to ensure that regional energy markets were integrated, as the first step towards European integration.

As part of the delivery of the third package for the development of a single European market in gas and electricity, ten network codes were established [89]. Once introduced, network codes have to be applied by the TSOs in member states. Of the ten network codes, the network codes for Capacity Allocation and Congestion Management (CACM) and Balancing were identified as the key areas for development. As such four target models were established by ACER for electricity market integration, three associated with CACM and one with Balancing [90]. These target models have the main aims of achieving a flow-based transmission capacity allocation method with a single platform for the allocation of long-term transmission rights, establishing European day-ahead market coupling, implementing continuous implicit cross-border trading and conducting pilot projects for the implementation of European balancing markets. The target models are illustrated in Figure 5 below in terms of ‘forward’ (greater than day ahead) and ‘short term’ (day ahead or intraday) markets.

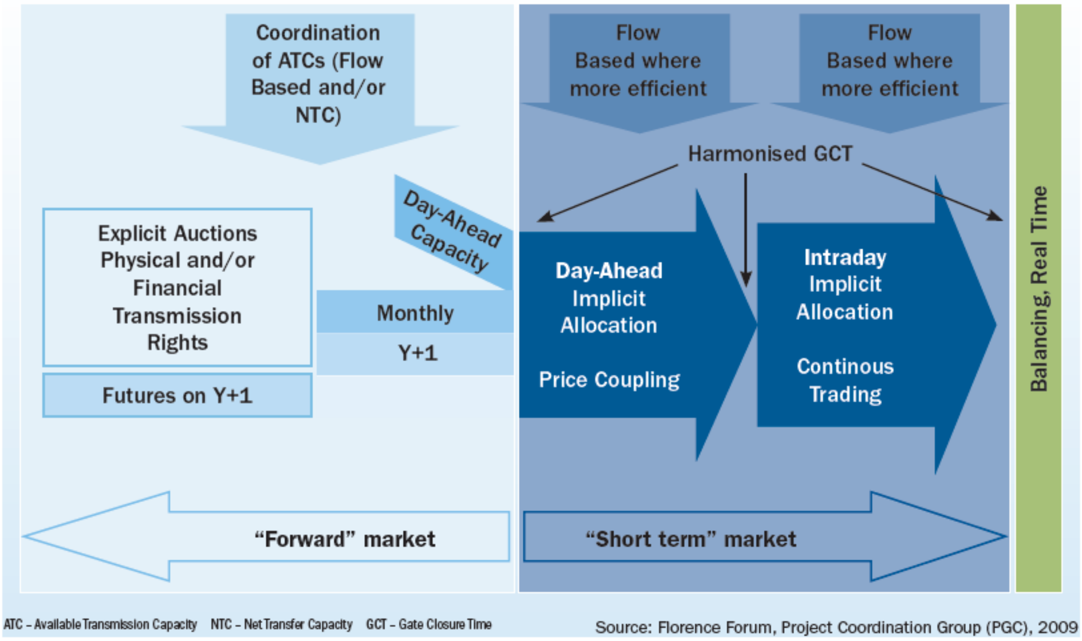


Figure 5 - Diagram of the EU single market target models aims, from reference [88]

The CACM guideline came in to force in August 2015 and sets out the single European market design based on four key elements [11]:

1. A day ahead market in which electricity and transmission capacity are auctioned together implicitly, provided network congestion is not present
2. Intraday markets – allowing participants to trade closer to real time, allowing for more accurate forecasting of generation and demand
3. A coordinated flow-based capacity calculation, with the objective of optimising the use of European transmission capacity
4. Designating bidding zones for congestion management – defined as the largest geographical area that electricity and transmission capacity can be auctioned together.

The target model of zonal pricing for congestion management in the SEEM and the designation of bidding zones is discussed in further detail in section 3.2.2

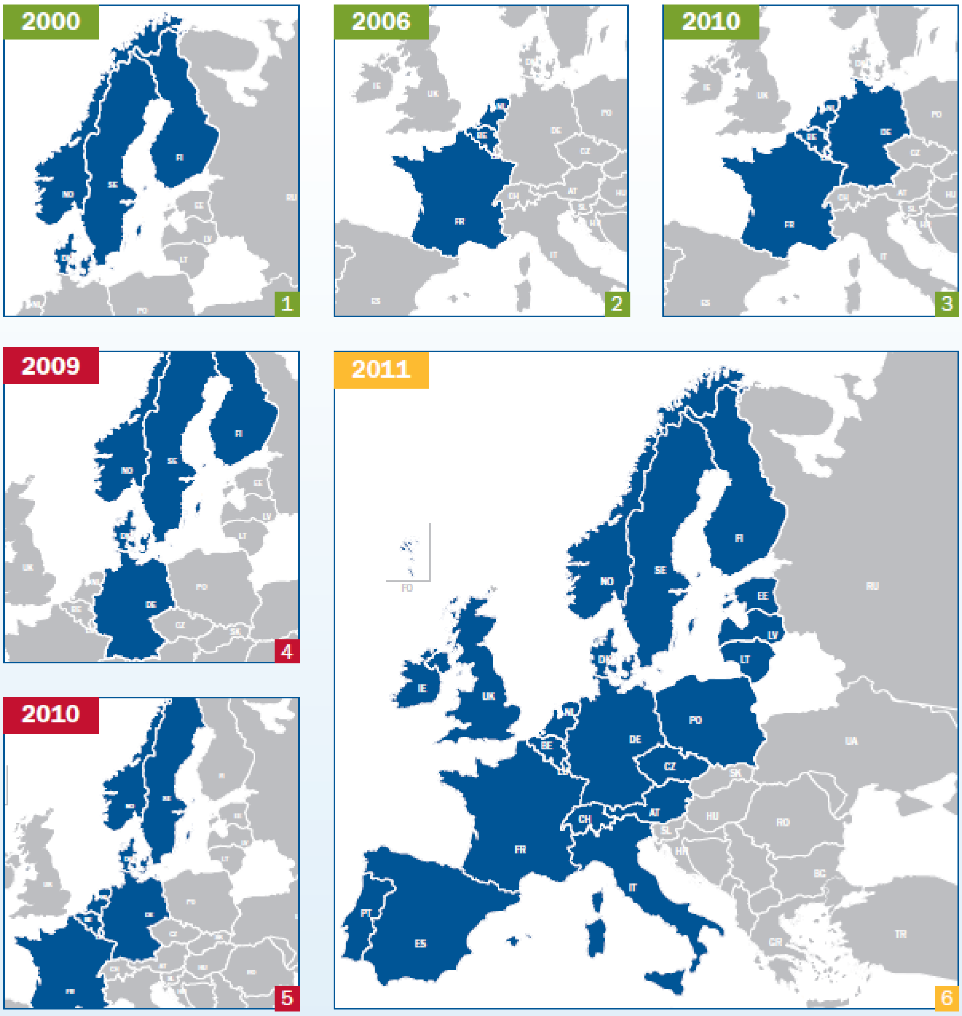
2.2.2. Development of the European single electricity market

Market coupling in Europe was a complex process, as many European states had isolated centralised markets with very different designs. The European target model for market coupling does not require regional markets to have identical design, but does require all participating markets to have a power-exchange trading platform with day-ahead and intraday trading, and a TSO-run balancing market. The target model includes explicit trades of interconnector capacity before the day-ahead trading period, and implicit trades (transmission capacity with energy) at the day-ahead and intraday trading periods [91]. Much work has to still be undertaken to get to this stage with intraday trading, as the primary focus was coupling the day-ahead markets through the Electricity Regional Initiatives (ERI) project.

ERI was originally set up in 2006 by the European Regulators Group for Electricity and Gas (ERGEG), with the purpose of streamlining the integration of European energy markets. The first action of the project was to split Europe into seven regions, with the purpose of improving regional integration before complete European integration. These regions are Northern Europe (NE) comprising Denmark, Finland, Germany, Norway, Poland and Sweden, the Baltic States (BS) comprising Estonia, Latvia and Lithuania, France, UK and Ireland (FUI), Central West Europe (CWE) comprising Belgium, France, Germany, Luxembourg and the Netherlands, South-West Europe (SWE) comprising France, Portugal and Spain, Central South Europe (CSE) comprising Austria, France, Germany, Greece, Italy and Slovenia and Central East Europe (CEE) comprising Austria, the Czech Republic, Germany, Hungary, Poland, Slovakia and Slovenia. The ERI also helped to develop the target model for the single energy market, with each region producing work plans based on the objectives of the target models [92]. The ERI also publish regular reports on the progress of market coupling projects [93].

Two market coupling processes were used in the development of the SEEM: volume coupling and price coupling. Volume coupling is the determination of power flows through a central algorithm, in which the power exchanges involved still set the separate market prices for their regions. Price coupling is the determination of both prices and power flows through a central algorithm. This usually involves an iterative process to optimise prices and then take account of transmission constraints [88]. Various regions in Europe were already price coupled before the ERI began to coordinate the price coupling of regions. The Nordic region has led the way for market coupling in Europe and indeed the world, as Sweden and Norway joined markets in 1996 to become the first international power market. Finland joined in 1998 and Denmark in 2000, fully integrating the Nordic market [94]. Belgium, France and the Netherlands also successfully price-coupled with one another in 2006. CWE launched day-ahead market coupling in 2010, and in parallel was volume coupled with Nordpool (NE) [88]. In 2011 CWE and NE price coupled with BS, SWE, Italy and the Czech Republic, with the Swedish-Polish and UK-French interconnectors including Poland and GB. Figure 6 illustrates these regional developments in market coupling from 2000-2011.

In 2011, the European Council set a deadline for the completion of the European internal energy market of 2014, with no EU member state left unable to access the European gas and electricity networks by 2015 [95]. An action plan was also published, with twenty-two actions involving the implementation of existing legislation, the operation of the retail market and the development of energy systems [96]. The key issues to achieving European market integration were in improving competition in the retail markets, investing in additional transmission capacity and harmonising network tariffs.



	Market integration mechanism	Region /countries
1	Price Coupling	2000 - Nordic Market integration: Norway, Sweden, Finland and Denmark
2		2006 - Trilateral Market Coupling: France, Belgium and The Netherlands
3		2010 - Market Coupling Mechanism Central West Europe (CWE): Germany, Belgium, France, Luxembourg, Netherlands
4	Tight Volume Coupling	2009 - European Market Coupling Company (EMCC): Nordic region and Germany
5		2010 - CWE and Nordic region
6	Price Coupling of Regions	2011* CWE, Nordic and SWE regions. (Portugal, Spain, Italy, Belgium, the Netherlands, Great Britain, France, Germany, Austria, Switzerland, Denmark, Norway, Sweden, Finland and the Baltic, including the price coupling on SwePol-link to Poland)

Figure 6 - Regional developments in market coupling from 2000-2011. From reference [88].

The BS, FUI, NE and CWE regions are commonly referred to as North-West Europe (NWE) and have made the furthest progress so far with market integration. After the PCR project in 2011, NWE day ahead markets were volume coupled as part of the ERI pilot project in February 2014. This coupling involved the markets of each state or region agreeing to harmonise various market mechanisms; gate closure must be harmonised at 12.00 Central European time (11.00 GMT), preliminary market results must be published, profile block orders must be introduced in all exchanges, price caps synchronised to -500€/MWh and 3000€/MWh and price thresholds that trigger a second auction [44]. The software used to calculate electricity prices and allocation is called EUPHEMIA (Pan-European Hybrid Electricity Market Integration Algorithm [97]. EUPEMIA calculates the price, net position and interconnector flows for each bidding area by maximising welfare (defined as the consumer surplus + producer surplus) such that the clearing price(s) will be the lowest most competitive price(s) for electricity [98].

Further to this in 2013, gate closure time for the Iberian market, MIBEL, was changed to noon central European time in order to fit in with the NWE region and operational procedures and market rules were updated to be compliant with the SEEM. MIBEL also undertook integration tests with the NWE pilot project, and volume coupling took place in May 2014 [67].

The 2014 internal market deadline proved effective, with 96% of TSOs found to be compliant with the third package's unbundling requirements by 2014, with only the exception of Ireland. Positive impacts of market coupling include increased market liquidity, competition and security of supply and more efficient use of interconnection. According to [67], wholesale electricity prices in Europe have fallen between 35-45% between 2008-2012 due to market integration. Greater instances of price convergence between interconnected states are a clear sign of increased liquidity in common markets. An example is the border between Spain and France. Figure 7 shows the percentage of time price differences (market splitting) occurred between these countries from 2007 until 2014. Recent developments in interconnection (increasing by a factor of three in this time period) and market liquidity have resulted in prices converging for over 90% of the time since 2011.

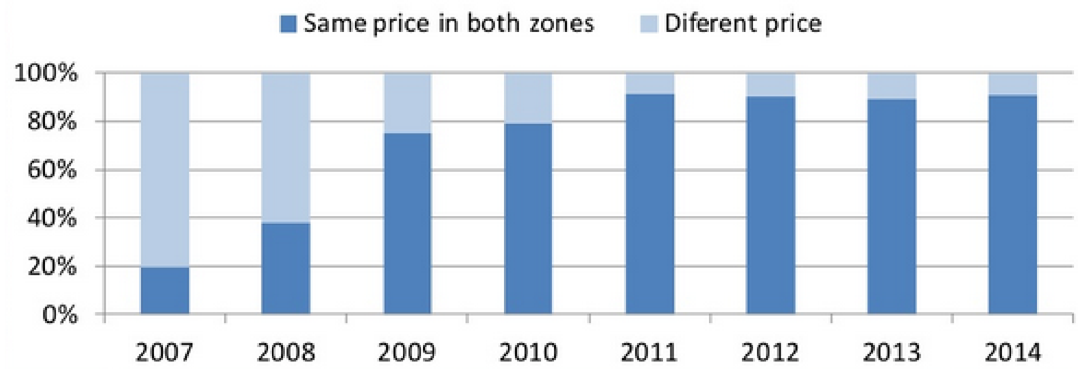


Figure 7 – Percentage of time cross-border energy prices differ between France and Spain, from reference [23]

2.2.3. Future developments for the SEEM

Much work has still to be completed until the target model for the SEEM has been met. To this end the European Commission has developed a list of Projects of Common Interest (PCIs) which they have identified as being significant in improving market integration. The current aim is to have 186 of 248 projects completed by 2020 [67]. ENTSO-E's 2014 overview of Internal Electricity Market-related project work [89] identifies two main categories with which to describe the current challenges facing the SEEM. The first is the "*effectiveness of price signals to stimulate appropriate investments and performances*". It is explained that the current market does not adequately represent externalities (such as adequacy and location) in energy prices. The second category of challenges has been labelled "*operational issues*" and describes the requirement for the electricity market to provide outcomes that suit the technical requirements of the power system (for example maintaining system stability and reserves). It is suggested that TSOs will require additional tools and control over the market outcomes, particularly as the penetration of intermittent generation increases. The report concludes by suggesting that the Target Model should be regularly reviewed and upgraded to meet the needs of the current market design.

In 2009, the European Wind Energy Association (EWEA) published a report stating that interconnection capacity in Europe must double by 2030 to allow for market integration with intermittent generation [99]. This has been recognised by the European Commission, who proposed in May 2014 to extend the European interconnection target from 10% of the total installed generating capacity by 2020 to a 15% interconnection target by 2030 (with interconnection levels at 8% in 2014) [67]. Germany and the Baltic region have been identified as critical regions requiring internal electricity transmission capacity. In addition to this ENTSO-E stated that there are four 'electric peninsulas' or areas of concern to developing the SEEM. These are GB and Ireland, Spain and Portugal, Italy, and the Baltic states, as shown in Figure

8. These areas were identified as requiring additional interconnection to ensure the required reserves for the integration of renewable energy sources [100].

Figure 8 - Four 'electric peninsulas' in Europe, as identified by ENTSO-E, from reference [100]

Accordingly, ENTSO-E publish a Ten-Year Network Development Plan (TYNDP) every two years, along with a Scenario Outlook and Adequacy Forecast (SOAF) and Regional Investment Plans (RIPs) to provide a Europe-wide outlook and identify any infrastructure or market development that could be required. The TYNDP 2014 was extended out to 2030 to be in line with EU targets [101], and was further built upon by the TYNDP 2016 [102]. The reports propose a €150 billion grid expansion, half of which will be developed by 2030, and the TYNDP 2016 has a particular focus on improving interconnection between the electrical peninsulas and the rest of Europe. It states that such improvements in market integration could reduce bulk power prices by €2-€5/MWh and CO_2 emissions in the power sector reduce by up to 80% compared with 1990 levels, 8% of which specifically due to network improvements. It also suggested that by developing projects on a pan-European scope could result in avoiding 30-90TWh of renewable energy spillage. However, one third of the 100 infrastructure projects identified in the TYNDP 2012 were delayed by at least a year, largely because of planning permission issues [89]. This highlights a key problem, that to be able to invest and develop in infrastructure in line with ENTSO-E plans requires a great deal of support from all member states, whose planning procedures and interest in investment will differ greatly.

The development of intraday and balancing markets so far is not as advanced as with the day-ahead markets. The Cross-border Intra-Day (XBID) Project has been set up involving the power exchanges and TSOs of France, Belgium, Luxembourg, the Netherlands, Germany, Switzerland, Austria, GB, Denmark, Sweden, Finland and Norway [89]. In 2013 the regional national regulatory authorities were unable to reach a consensus about which IT provider to use for the intraday market, and the European Commission had to step in to assist the decision-making process. Following detailed negotiations, the power exchanges of NW Europe came to an agreement to jointly develop an intraday trading platform with service provider Deutsche Boerse. This will be based on a model of continuous cross-border trading, in which orders by market participants can be matched between any two countries providing transmission capacity is available [103]. Local Implementation Projects have been set up at various borders to adapt local arrangements, adjust IT systems, ensure equal treatment between PXs and make sure that systems are ready for the testing of the XBID project. Currently, project plans have the XBID solution complete by January 2018 [104]. The Tradewind study completed in 2009 compared cross-border trading at day-ahead and intraday timescales, and found that intraday trading would save €1-2billion in annual operational costs [99].

Numerous additional sources in the literature suggest further policies for the SEEM. One source suggested that having separate day-ahead, intraday and balancing markets would reduce overall liquidity and a single platform should be introduced [105]. Another has suggested a Europe-wide enhanced forward services market instead of a capacity market, so that future system flexibility needs can be met by a suitable range of services [91]. A market design paper by ENTSO-E suggested that the demand-side should be able to participate in all markets, including day-ahead, intraday, balancing and ancillary services to encourage system flexibility [87]. It has also been suggested that the introduction of large regional control centres and the use of dynamic line ratings would increase the available transfer capacity [88]. Differing network tariffs in different countries have also been identified as an issue needing more attention in Europe, due to the impact this could have on cross-border competition. It has been suggested that a set of transparent European-wide rules on network tariffs should be established. These are still in the preliminary stages of development [67].

All of these suggestions for development of the SEEM require further market design collaboration. In addition to these suggestions, in 2014 the 2030 Energy Strategy was agreed upon by EU countries, based on a policy framework document that includes some EU-wide targets by 2030 [106]. These targets are: a 40% reduction in greenhouse gas emissions (compared with a 1990 baseline), 27% of energy from renewable sources and energy savings of 27% (compared with the business-as-usual scenario). To meet these targets a great deal of development will have to take place on European energy markets, transmission networks and interconnection to ensure that renewable power sources are utilised in the most efficient way.

2.3. Chapter 2 conclusions

Since the 1990s market liberalisation has taken place throughout Europe with the aim of increasing market liquidity and competition and decreasing costs to the consumer. The European Union directives at first only focused on liberalisation of the electricity sectors, resulting in many European states having very different market structures. When it came to the formation of a single European electricity market, many states had to alter market rules (e.g. the time of day-ahead gate closure) to participate in the market-coupling algorithm. Focusing first on regional coupling, the SEEM has now progressed to cross-border market coupling among most EU states at the day ahead timeframe. The coupling of intraday markets and improving interconnection between states is the current focus of SEEM development, to support future power systems with higher penetrations of renewables. However, the coupling of intraday markets must be carefully planned as any additional costs from market inefficiencies will be passed down to consumers

GB was one of the first markets to undergo liberalisation in Europe. However, the majority of wholesale trading in GB still takes place through confidential bilateral trades rather than through the spot markets. This means that there is very little transparency on the price points of wholesale electricity trading and how this is being passed to the consumer through energy bills, making it difficult to quantify the benefits of market liberalisation in GB.

In addition to liberalisation, the drive towards carbon reduction has resulted in the European energy mix changing considerably in recent years. The Large Combustion Plant Directive has resulted in the closure of the most polluting thermal plant and the penetration of low carbon generation has increased to meet European targets. In Britain the Renewables Obligation proved very effective in incentivising new renewable capacity, but also resulted in additional expense to the consumer through increasing electricity prices. In 2013, Electricity Market Reform was introduced, as the UK Government focused on the 'energy trilemma' targets of reducing emissions and costs while maintaining security of supply. This trilemma occurs because these targets are conflicting, low carbon generation can be more expensive than carbon producing and less able to contribute towards security of supply. Interestingly, during the course of this work, some forms of low carbon generation (such as offshore wind and solar PV) have reduced costs dramatically and are now competitive with thermal generation. In addition to this, after the bulk of this work had taken place GB has also passed much more ambitious carbon reduction targets into legislation [107]. It has been said in the UK Parliament that with cheap renewable energy the 'trilemma' now no longer exists [108]. However it is also true that it will not be possible to meet net zero carbon reduction targets and maintain security of supply with only offshore wind and solar PV, and that significant cost reductions are still required for alternative generation and storage technologies. The effectiveness of various policy mechanisms introduced to encourage carbon reduction have been discussed in this chapter. It is clear that such schemes need to be very carefully thought through to ensure that they are not only effective in encouraging low carbon generation, but also are not unnecessarily expensive to the electricity consumer. An example of this is the transition between the ROC and CfD subsidy schemes resulting in FiDER contracts with considerably higher strike prices than those won in competitive auctions the following year.

It has been seen that as market liberalisation has taken place, energy policies in GB and Europe have moved from those motivated by economic issues, e.g. increasing market liquidity and lowering prices to consumers, to those motivated by carbon reduction and renewable generation targets. One of the key questions of this work is how these two very different policy aims interact when they are used in tandem, in particular how the market mechanism of zonal pricing for congestion management in the SEEM can impact on a carbon reduction subsidy framework such as CfDs in GB. The following chapter focuses on market based methods for congestion management and discusses the forms that the CfD mechanism could take if GB were to split into more than one bidding zone.

Chapter 3.

Congestion management concepts

In a power system, congestion occurs when the electricity network transmission capacity is not sufficient to allow the traded energy to be delivered. Many countries have a form of bilateral trading in which transmission constraints are not taken into account, with system balancing occurring once trading has taken place. As such, a congested network will not be able to meet demand at least cost because bilateral contracts and market trades are not able to be delivered in their entirety without violating system operating constraints such as current, voltage and thermal limits [109].

Kumar et al define congestion management as "*the necessary actions to ensure that no violations of the grid constraints occur"* [109], which usually falls into one of two categories: deterrent methods and corrective methods. Deterrent methods are mostly market-based and involve using pricing mechanisms to deter energy trading that could cause congestion from taking place, this includes locational marginal pricing (nodal pricing), market splitting (zonal pricing) and transmission capacity rights auctioning. Corrective methods on the other hand allow electricity to be traded freely and rely on the system operator to redispatch and counter-trade to meet demand requirements [110]. Corrective methods have the advantage that all generation can participate in the wholesale markets at all times. However, this can also result in generators taking advantage of the redispatch process by altering their contracted output in congested areas to ensure scarcity payments [111]. Systems with corrective methods thus have to be heavily regulated to ensure gaming does not take place [112].

This work focuses mostly on market-based deterrent methods, as the basis of congestion management in the SEEM comes from article 16 of European regulation EC714/2009 on conditions for access to the network for cross-border exchanges in electricity, which states that transmission network congestion must be dealt with using non-discriminatory market-based solutions [113]. The following sections introduce and compare the different forms of market-based methods of congestion management, before going on to discuss the forms of congestion management used in GB and Europe and the current developments under the SEEM.

3.1. Market-based deterrent methods

Market-based methods for congestion management have the advantage that system constraints are reflected in the market price for electricity, thus providing signals to investors to build generation in areas/nodes where export is not regularly impacted by congestion. The three types of market-based congestion management methods discussed here are nodal pricing, zonal pricing and transmission capacity rights auctions. The following sub-sections introduce and explain the mechanisms behind these methods, and go on to discuss their comparative advantages and disadvantages.

3.1.1. Nodal pricing

Nodal pricing is currently used by some US markets (PJM, ERCOT, New York and New England), New Zealand and Chile [114]. It can also be referred to as locational marginal pricing, as the locational marginal price (LMP) is calculated for each node in the network. The LMP calculation is based on the merit order of the electricity market participants, the electricity demand and the available transfer capability (ATC) between nodes. All generator offers for a set trading period are placed in price order (merit order) and the locational marginal price is the least cost solution for meeting nodal demand, taking account of transmission losses. Each generator offer accepted at the point of the marginal price or below will gain the marginal price, regardless of the offer provided. When ATC is not reached and congestion is not present, the LMPs of neighbouring nodes will be identical and at the most cost-effective price for the system. However, when congestion is present, the cheapest generators will not be able to serve all of the demand at import-constrained nodes and so more expensive generation will have to be used within the import constrained area and the LMPs will be higher at these nodes.

The LMP can also be described as the price of serving an additional MW of power at the given node, including the associated cost of transmission losses and congestion, thus expressing the opportunity cost of transmission investment, including losses [112]. The marginal cost of transmission can be seen by the change in locational prices between areas, also known as the congestion rent [115]. Congestion rent can then be collected by the transmission system owners and used to cover the cost of redispatching and other operational measures to ensure that demand is met. It can also be used to maintain or increase transmission capacity [116].

Nodal pricing can also be used to give signals for investment in generation. Generation at a specific node will gain the nodal LMP in market revenues for electricity production. The nodal price will differ depending on the current state of the power system at the node. If imports to a node are constrained due to the ATC then the nodal price will likely be high as the more expensive generation at the node will need to run to ensure demand is met. Likewise, if the node is export-constrained (i.e. there is an excess in available generation) then the nodal price will likely be low as the less expensive generation is sufficient to meet demand and not all of the surplus can be exported. In this manner, nodal pricing provides a price signal to new generation to build at a node with higher revenues, and discourages investment at nodes where export is constrained. As such, nodal pricing is often described as the most efficient form of transmission pricing as it allows the optimal generation dispatch to meet demand at the lowest cost of generation, and thus the maximum social welfare, whilst taking into account line and system constraints and providing signals to longer term investment, both in generation and transmission [117].

3.1.2. Zonal pricing

Zonal pricing is found in Australia, Scandinavia and more recently the SEEM. Zonal pricing involves the aggregation of groups of network nodes into zones, representing areas which typically experience the same LMP. Zonal pricing can also be described as market splitting, as zonal prices only diverge (and zonal markets 'split') when congestion occurs.

The calculation of a marginal price for a particular zone is based on the merit order of generation, zonal demand and the ATC between zones. When the network is not congested and market trades do not exceed the ATC between zones, all of the zones will clear at the same system marginal price. When congestion occurs between zones, prices differ and generation in a specific zone will gain the zonal marginal price (ZMP) in revenues for electricity production [117]. As with nodal pricing, import-constrained zones will have higher zonal prices than export-constrained zones, and investment in generation will be incentivised in import constrained zones with higher revenues.

Zonal pricing is utilised in the Nordic market, with the zonal configuration illustrated in Figure 9. Norway and Sweden both experience congestion between the larger load centres and generation in the south and the smaller settlements in the north. When congestion occurs between two zones they split and each zone clears at a separate ZMP.

Zonal pricing involves the designation of zones in which nodal prices are often the same and internal congestion is uncommon. In theory this can result in the network being used more efficiently than without zonal pricing as it can reduce the need for redispatch and provide signals to investment in generation that alleviate congestion. The correct designation of zones is important to ensuring an efficient, competitive market in which congestion is managed and disincentivised.

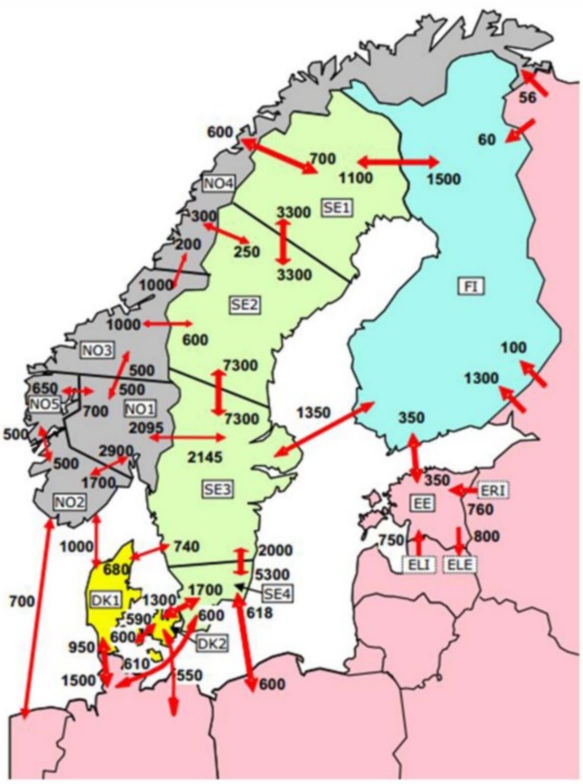


Figure 9 – Zones and transfer capacities in the Nordic Market, from reference [115]

The literature provides conflicting views as to whether a greater number of bidding zones allows for more efficient congestion management. A report from Frontier Economics and Consentec on the current bidding zones configuration in Europe states that smaller bidding zones can lead to less competition, decreased liquidity and more problems with market power [118]. Lower market liquidity could lead to increasing risk in investment in new generation [20]. However, ACER argues that when measuring market liquidity that there is a need to consider trading between zones as well as within zones [119]. An EA Energy Analyses study for the Nordic council of Ministers concluded that additional bidding areas in Sweden, Norway and Finland would improve market efficiency through better management of commonly occurring congestion [120]. In general the more interconnected the area, the less that increasing numbers of bidding zones will improve the efficiency of congestion management, due to higher instances of similar and equal prices occurring in highly interconnected regions [121].

The impact of bidding zones on market power has also been discussed in the literature, with sources suggesting larger zones and higher liquidity result in less chance of a significant market power [118], [21]. Europe already has several large zones where considerable market power can be observed however, for example France and Germany are still dominated by monopolistic generation companies. An interesting case is Sweden, which was divided into four bidding zones in 2011 due to significant transmission constraints being present. However, since this split the TSO has faced a case under competition law with the European commission, where it has been found to be discriminating against non-Swedish producers by limiting imports from Denmark at times of congestion in an effort to keep Sweden trading as one price zone [20].

3.1.3. Transmission capacity rights auctions

Transmission capacity rights auctions can take several forms. Explicit transmission capacity rights auctions involve the trading of rights to use the transmission capacity over a set period of time, separate from electrical energy markets. Implicit transmission capacity rights auctions involve the simultaneous trading of transmission rights within electrical energy markets [122]. Physical transmission capacity rights actions involve the trading of rights to transfer a certain volume of electricity over a transmission line within a certain time period. Financial transmission capacity rights auctions allow the holder to be paid the difference in price between two neighbouring markets, but do not correspond to any right to influence the flow of electrical energy between said markets.

Explicit physical transmission capacity rights auctions were a logical step for the developing SEEM, as a way of ensuring that the cross-border available transmission capacity was not exceeded. The bilateral calculation and then auction of cross-border transmission capacity is the simplest method of transmission capacity rights auctions, with a joint multi-country approach being more complex but arguably a better representation of actual existing network topologies. For example in mainland Europe a trade of transmission capacity rights between two countries could impact on their ability to trade with all of their neighbours, which is not captured when each separate border has a single bilateral market for transmission capacity rights.

Explicit physical transmission capacity rights auctions are a simple method of minimising congestion and can be introduced to differing forms of existing markets. This market-based approach allows all generation to access the competitive auction. However, the separate trade of generation and transmission capacity rights, sometimes over different timeframes, can introduce difficulty in accessing the international market [112].

3.1.4. Market-based methods comparison

Bilateral explicit transmission capacity rights auctions have traditionally been used for cross-border electricity trading, with transmission capacity between two countries often calculated at the day-ahead timeframe without taking account of loop-flows from neighbouring systems. However, market-based mechanisms for congestion management that include flow-based calculations of transmission capacity for groups of neighbouring countries result in more efficient use of the interconnected transmission network, and are a requirement of the SEEM [88]. Furthermore, the implicit allocation of transmission capacity with energy trading (market coupling) allows easier access to market for all generators, also improving the efficiency of using the available transmission capacity and thus increasing market liquidity and instances of price convergence [22].

Zonal pricing and nodal pricing have the advantage over transmission rights auctions in that multiple interconnected regions can be integrated and the implicit trading of transmission capacity and energy included in the same platform. Zonal pricing has the advantage over nodal pricing in that it is simpler to implement, and can be implemented over multiple areas which have separate internal markets and different market structures. One issue with zonal pricing compared with nodal pricing is that it does not help to manage congestion within zones, only between them. As such, areas with zonal pricing have to manage internal congestion independently. Zonal markets were originally used in some regions in the US, but a large amount of congestion within zones still existed and could not be eradicated completely. Thus Nodal pricing has been introduced in markets such as PJM and California. It has been argued that nodal pricing can result in more volatile price differences than zonal pricing. In the US, markets use Financial Transmission Rights (FTR) to compensate for this [112].

In the literature, various papers argue for nodal pricing as a more complete solution than zonal pricing, as it requires a much more detailed representation of the transmission system, solving for every transmission line. The Competition and Markets Authority (CMA) Energy market investigation in 2015 summarises the work to date on the potential economic benefits of nodal pricing in GB, in which the net benefits range from £2m-£73 per annum, with the largest benefits occurring where losses and congestion charges were both included in the LMP [123]. However, it should not be assumed that nodal pricing is always the ideal solution. It has been argued by Green [124] that gains from locational marginal pricing in a system with market power influences will be even higher, as the impacts of ignoring locational transmission costs and constraints can be amplified by market power. Bell et al highlight that the effectiveness of locational marginal pricing in influencing locations of new power generation facilities depend very much on how potential network users can analyse the system and how they approach the risks involved [117]. Whilst the ideal solution would be to locate generation closest to load centres, this is not always possible when considering ideal renewable generation resource. Furthermore, a system in which generation is most incentivised to locate close to major load centres could result in problems with security of supply in more remote locations.

In 2011, Climate Policy Initiative Berlin commissioned a report from the Energy Policy Research Group at Cambridge University on congestion management in European power networks [112]. This paper compares the congestion management solutions already discussed in this section, judged on criteria such as the ability to integrate with domestic congestion management, the ability for joint allocation of international transmission rights and the ability to integrate with day ahead, intraday and balancing markets. This comparison is shown below in Table 6. It was argued that effective Europe-wide congestion management requires the integration of domestic and international congestion management schemes with joint allocation of international transmission capacity in the day-ahead and intraday timescales. The report concludes that nodal pricing with full locational marginal pricing is the most effective method when compared to other market-based methods, and would produce the greatest benefit in the single European energy market.

Table 6 - Capabilities of various market-based methods of congestion management, from reference [112]

Aspects of congestion management and balancing markets that benefit from European integration, and market design options to achieve this integration.

	(i) Integration with domestic congestion management	(ii) Joint allocation of international transmission rights	(iii) Integration with day ahead energy market	(iv) Integration with intraday/ balancing market	(v) Transparency of congestion management
Bilateral transmission rights auction	No	No	No	No	No
Joint multi-country auction of NTC rights	No	Yes	No	No	No
Multi-region day-ahead market coupling (zonal pricing)	No (only at zonal level)	Possible	Yes	No	No
Nodal pricing	Yes	Yes	Yes	Possible	Yes

Although it is widely accepted that nodal pricing is often optimal, it is also true that it is much more complex and thus more difficult to introduce to multiple regions [117]. A zonal pricing model has been chosen for the SEEM, outlined in the CACM guideline [11]. The European Energy Regulators Group has stated that this was because the nodal pricing solution would require much more drastic changes to the current market design. In a report on CACM they stated:

"It is therefore important to consider the nodal approach as the ultimate goal and (technically and economically) optimal solution for capacity calculation within capacity allocation and congestion management, but at the same time to pursue the practical development and implementation based on the flow-based calculation [zonal pricing]" p30 [125].

3.2. Current applications of congestion management

3.2.1. Congestion management in GB and Europe

Currently GB uses corrective methods for internal congestion management. Electricity is traded freely without a locational element, and the system operator (National Grid) is responsible for balancing the system through counter-trading and redispatch. This takes place through the balancing mechanism, in which generators and large consumers can offer to reduce demand or increase generation or bid to increase demand or reduce generation. The balancing mechanism is socialised to all generation through Balancing Services use of System charges, which do not have a locational element. However, there are locational elements for generation in GB in the form of Transmission Network use of System (TNUoS) charges. The balancing mechanism and TNUoS are explained in more detail in section 2.1.1.

Internal congestion management varies in different European states. Many have a corrective method similar to GB, involving electricity market trading without taking account of congestion in the transmission system, with a system operator managing any congested lines by redispatch. Examples of other countries using central redispatch for congestion management are Germany, Spain and the Netherlands [112].

Historically, cross-border interconnection between European states first occurred to provide emergency response. Since the drive towards liberalisation and the SEEM by the European commission, cross-border interconnection is expanding and improving in Europe. Currently Europe is also undergoing a considerable increase in the amount of energy generation from low carbon sources, such as wind and solar power. Such generation is typically geographically dispersed and intermittent and so network flow patterns are becoming increasingly weather dependent and congestion more variable. Managing such congestion in an optimal way is important to gain the most out of the available intermittent resources and minimise curtailment. The establishment of a suitable model for cross-border congestion management is thus integral to the efficiency of the single European energy market.

As the European market has developed, the explicit auctioning of transmission capacity rights has been the most common method for cross-border capacity allocation and congestion management, for example between Germany and the Netherlands, Germany and Denmark, Belgium and the Netherlands and France and GB [110]. Scandinavia, on the other hand, developed a zonal pricing system for congestion management, involving Norway and Sweden splitting into various bidding zones at times of congestion. This model was chosen to be used for cross-border congestion management in the development of the SEEM.

As part of the SEEM, cross-border trades between GB and its interconnected neighbours, France, the Netherlands and Ireland at the day-ahead timeframe are undertaken through the SEEM chosen mechanism of zonal pricing, through the APX and N2EX power exchanges, also discussed in section 2.1.1.

3.2.2. Zonal pricing and the single European electricity market

The target model of zonal pricing in the SEEM is detailed in the guideline for Capacity Allocation and Congestion Management (CACM), which entered into force in August 2015. The CACM guideline calls for bidding zones to be established that were consistent across market time frames, to be reviewed every two years. The local TSOs are responsible for coordinating cross-zonal redispatching or countertrading in their established regions. ENTSO-E define a bidding zone as *“the largest geographical area within which market participants are able to exchange energy without capacity allocation”* [126]. The CACM guideline defines a zone as *“a bidding area, i.e. a network area within which market participants submit their energy bids day-ahead, in intraday and in the longer term timeframe*” [11].

The current bidding zones in the SEEM are illustrated below in Figure 10. For the most part, these bidding zones take the form of state borders; however, it can be seen in the case of Norway, Sweden and Italy that some states are split into several zones, indicating transmission congestion is common within each of these countries.

ENTSO-E define various criteria to assess the efficiency of bidding zone configurations, including impacts on market liquidity, impacts on the operation of the balancing mechanism and impacts on the location and frequency of congestion [11]. The CWE Price Zone Study Task Force was established in 2012 with the aim of analysing the current zones in CWE and judging if any revisions need to be made. The CWE Price Zone Study Task Force identify three reasons to apply a market split, in order to [127]:

1. Manage inner-country congestions, by applying the split at the place of congestion
2. Manage congestions that are expected in the future, due to shortage of energy stock
3. Manage a congestion in a bidding area caused by loop flows, by applying a market split in a neighbouring bidding area on the path of the exchange

Figure 10 - Current bidding zones in the SEEM, from [20]

Various studies have been undertaken in Europe to investigate if different configurations of zones may result in social benefit. The bidding zone of Austria and Germany has been a particular focus. A joint report from the TSOs of the Czech Republic, Hungary, Poland and Slovakia argues that the allocation of Germany and Austria as a single zone has resulted in a much higher occurrence of loop flows for neighbouring countries [121], prompting ACER to commission an early bidding zones review in 2015. The German and Austrian regulatory authorities opposed the early bidding zones review, and the German regulatory authority (BNetzA) commissioned a Frontier Economics and Consentec study on the region, which concluded that there were no areas of sustained congestion in the Germany and Austria region and no evidence that loop flows impact on the bidding areas, and as such there was no need for further market splitting in this region [128]. However, a further case study on Germany completed by Aachen University compared several options for market splitting in Germany and Austria, finding that market splitting eased congestion on the cross-border transmission lines, but did not greatly impact the German market or neighbouring market areas [18]. These reports, along with interviews with various TSOs in Europe, are summarised in the CWE Price Zone Study Task Force Report [127], which concluded that the function of market splitting for congestion management was not explored in enough depth in relation to loop flows in any of the work reported. The bidding zone review resulted in ACER recommending that Germany and Austria split into separate zones [129]. In May 2017, the German and Austrian TSOs agreed to split into two separate bidding zones from October 2018 [12]. Further discussion has taken place about the congestion between the north and south of Germany, and it has been speculated that Germany should also form two zones, however no formal bidding zone review process has yet gone underway. Internal congestion within France and Poland has also been the subject of recent bidding zone reviews [13].

3.3. Future applications of congestion management within GB

It has been seen with Germany and Austria that the SEEM bidding zone review process can result in the creation of new bidding zones, in this case against the wishes of the states included in the original bidding zone. This work considers the possibility that GB could become two bidding zones in the SEEM, and this section explores the reasoning behind a possible zonal split at the Scottish-rGB border, before discussing the impact that this could have on the CfD framework and investment in low carbon generation in GB.

3.3.1. Zonal splitting within GB

GB is currently a single zone in the SEEM, with the single electricity market of Northern Ireland and the Republic of Ireland forming a separate single zone. However, with much of the conventional thermal and nuclear generation due to retire in Scotland over the next decade and increasing wind development, it is possible that the boundary between Scotland and the rest of GB (rGB) could become constrained more frequently, especially in periods of high wind resource and in either direction at different times. Figure 11 illustrates the Scottish transmission system and the major power flows, showing a habitual power flow from Scottish generation to the south. National Grid's Electricity Ten Year Statement (ETYS) from 2015 states that:

"The high volume of new contracted renewable generation seeking connection throughout Scotland is expected to create significant power flows through the Scottish networks to reach demand in England. Renewable generation connection throughout Scotland is expected to increase across all ETYS scenarios, so the increase in the required transfer capabilities over the ETYS period indicates the need to reinforce the transmission system in order to create the extra capacity for exporting power from Scotland to England." p44 [130]

The 2015 ETYS also states that embedded generation can also impact on future boundary requirements, with more than 2GW of small-scale embedded wind capacity likely to be installed by 2030.

Figure 12 shows the economy-required transfer for various future energy scenarios (FES) from 2015/16 until 2035/36. It can be seen that the base capability of the B6 boundary in 2015 is insufficient to meet the predicted transfer. However, with the additional series and shunt compensation in 2016 and completion of the Western HVDC link in 2018 the transfer capability is taken up to 6.6GW, which is sufficient for the No Progression scenarios, but none of the others. National Grid's 2016 Network Options Assessment (NOA) states than any further development of transmission capacity at the B6 boundary will not occur until 2023 [131].

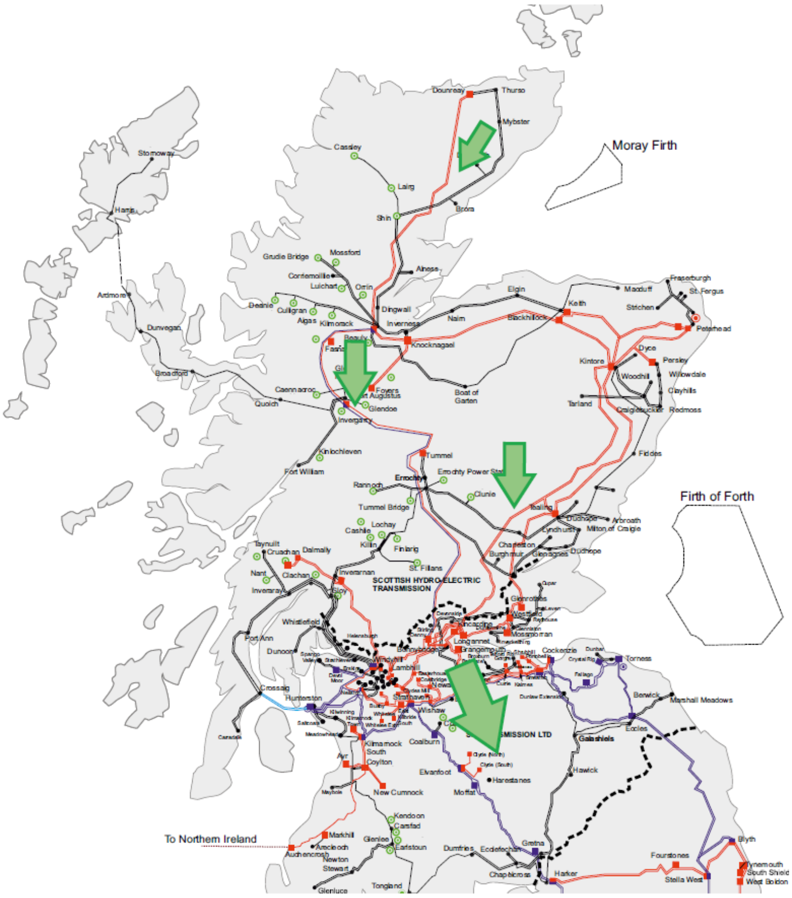


Figure 11 - Scottish transmission system, arrows indicating major power flows, from [130]

To ensure efficient price signals, it should be ensured that bidding zone configurations properly reflect network constraints. As bidding zones in the SEEM have to be reviewed every two years it is also conceivable that at some point, the prospect of Scotland becoming a separate bidding zone to rGB could be possible, due to the increasing congestion of transmission capacity at times of peak renewable resource.

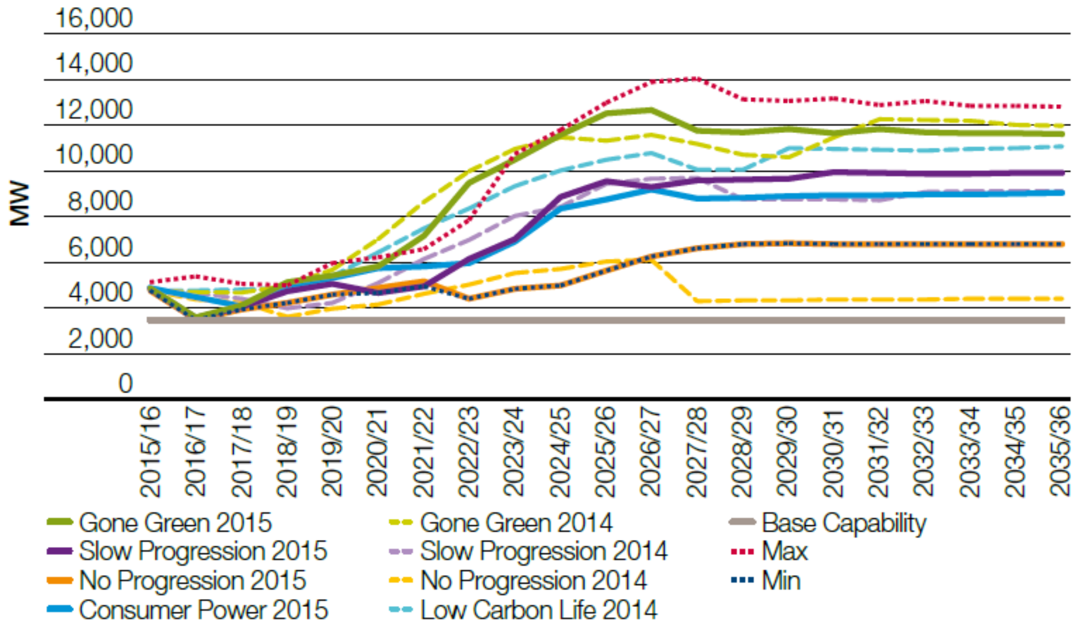


Figure 12 - Economy-required transfer for FES and base capability for boundary B6 from 2015 ETYS p58 [130]

Considering this zonal setup, with either very low or high zonal prices in Scotland at times of congestion depending on the wind resource, it is interesting to explore how this might impact the current low carbon subsidy system. As described in Chapter 2, CfDs are based on a top-up payment between a reference price (currently taken as the day-ahead market price for intermittent generation) and the agreed strike price. If this reference price became the zonal day-ahead price this could hugely impact on the top-up and pay-back payments to and from generators in Scotland. If we assume that market splitting occurs mostly due to high wind resource (thus causing low zonal prices) then the levy control framework budget could be used up much faster with the higher top-up payments to generators in Scotland. It is conceivable that the CfD framework would have to be redesigned so as not to use up this budget too quickly. It is worth highlighting that there have been no studies in the literature exploring the impact of introducing multiple price zones to a region with a subsidy framework including a contracts for difference mechanism.

3.3.2. EMR and zonal pricing

If zonal pricing were introduced to GB with Scotland as a separate price zone from rGB, there could be various impacts on electricity generation projects, both existing and in planning and development. On the formation of the SEEM bidding zone configuration in 2014 the Future Trading Arrangements (FTA) team at Ofgem conducted a literature review on zonal pricing, concluding that bidding zone configuration had been shown to impact on market efficiency, liquidity, market power, investment signals for new generation, distributional impacts and costs of trading arrangement transition [20]. It was also stated that the configuration of bidding zones is widely understood to impact on short-run signals for utilisation of existing capacity and also provide long run signals that may impact on investment decisions.

True zonal pricing in GB would involve all generation revenues being impacted in the case of transmission congestion, to provide price signals to investors to build new generation in areas without export constraints. However, currently in GB the subsidy regime to low carbon generation (CfDs) separates this generation from price signals, by offering top-up payments to a guaranteed strike price. Because of this, zonal pricing may not impact on low carbon generator revenues per MWh generated for existing CfD projects, but could impact on the amount of generation allowed to gain revenues in the case of an export-constrained high wind scenario. Currently within GB, all generation participating in wholesale trading for a certain period gain revenues, with no adverse impact on revenues due to transmission constraints and redispatch occurring after gate closure. However, the introduction of zonal pricing within GB would result in some generation only being able to earn revenues in exporting zones if transmission congestion is present between zones, and so generation which may have previously been constrained but still receive revenues would no longer do so.

The introduction of two price zones within GB could also impact on the reference price used for the calculation of CfD top-up payments as, if congestion were present, there would be separate zonal prices in Scotland and rGB. With lower thermal output in Scotland and an increasing penetration of low carbon generation, the Scottish zone will more likely have a lower average zonal price than that in rGB due to the lower running costs of low carbon generation. Ofgem have identified that reference prices used in the calculation of CfD top-up payments would be one of the key considerations for GB if alternative bidding zone configurations were being considered [20]. The CfD top-up calculations and auction format in relation to these reference prices could take one of two forms: (1) using zonal reference prices in the top-up payment calculation without changing the auction format and (2) using zonal reference prices in the top-up payment calculation and changing the auction format to account for the locational signals, i.e. introduce zonal strike prices. These two possible forms of the CfD mechanism are discussed in greater detail in the following two sections.

3.3.2.1. GB-wide Strike Price

It is possible that the CfD mechanism could be run in its current format in a two-zone GB, with the only difference being the calculation of top-up payments from the appropriate zonal reference prices. The CfD strike prices would still be allocated in a single auction, based on the lowest strike price bids from any zone. In this case, when congestion occurs due to high wind resource in Scotland, the Scottish zonal price will drop due to the lower short-run costs of wind generation and so top-up payments to generators in Scotland will be higher than those in rGB. This is illustrated in Figure 13, which shows example zonal prices and top-up payments for wind generators with an example agreed strike price of £90/MWh in Scotland and in rGB at times with and without network congestion. In this case, generators in Scotland and those in rGB gain the same overall revenues. The increased top-up payments to Scottish generation at times of congestion would use up the LCF budget faster than if GB were a single bidding zone with a single reference price.

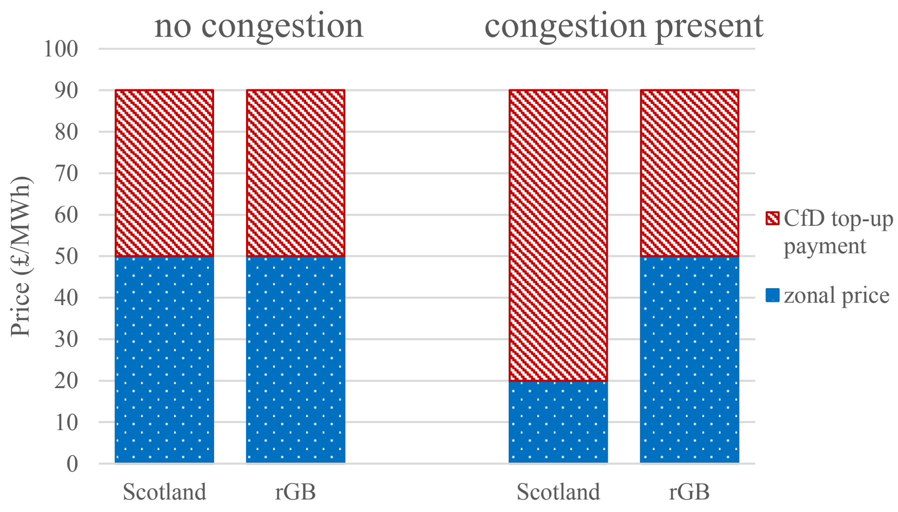


Figure 13 - Example zonal prices and top-up payments under a zonal reference price at times with and without network congestion

3.3.2.2. Zonal strike prices

Another possibility is that separate zonal strike prices would be introduced, so as not to use up the LCF budget more rapidly than if GB were a single price zone. This would also represent the price signals in each zone as intended by zonal pricing. In this case it is possible that the total annual top-up payments to generation (or overall uplift) would be equal in both zones, regardless of the zonal reference price, to give the same overall subsidy to generation in Scotland and in rGB. The auction process could be separate for rGB and Scotland or perhaps a single auction for both, with clearing based on the minimum impact on the LCF rather than the minimum strike price. It would be expected in this scenario that Scottish generation would have to bid at a lower strike price than generation in rGB to gain a CfD, due to the lower average zonal price. Generation in Scotland typically has a higher capacity factor, and so may still be able to compete. In a scenario with zonal strike prices, when transmission congestion does not occur (as zonal pricing hopes to encourage), then the reference price in both zones would be equal, and top-up payments to Scottish generation would be lower than that in rGB. When transmission congestion did occur, generation in Scotland would receive a greater top-up payment to generation in rGB. This is illustrated in Figure 14. This would work out overall as the same amount of top-up to generation in Scotland and rGB, but Scottish generation would gain a lower overall revenue.

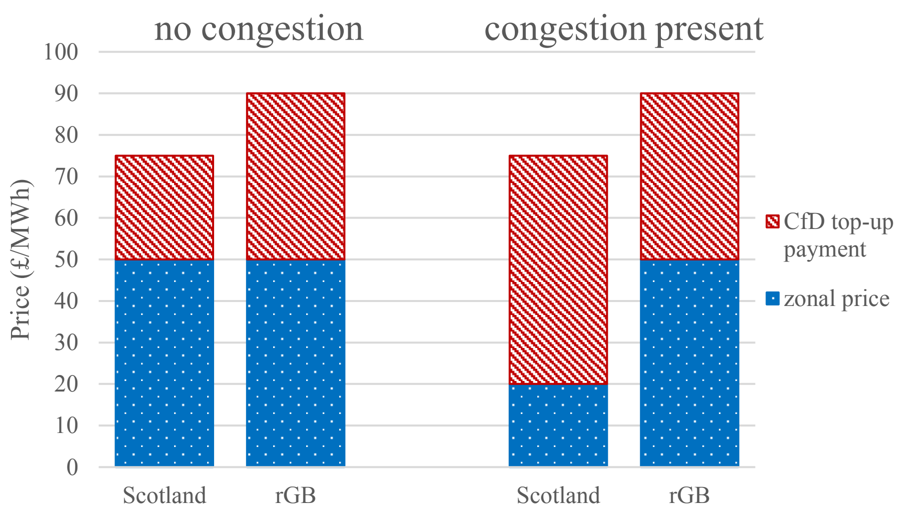


Figure 14 - Example zonal prices and top-up payments under a zonal strike price at times with and without network congestion

3.3.3. Thesis Premise

The central concept of this thesis is that introducing zonal pricing to GB, with Scotland as a separate price zone, could result in disincentivising the development of the Scottish wind resource under the current subsidy system of feed-in-tariffs with contracts for difference, depending on the form that this mechanism could take under zonal pricing.

This chapter has discussed the concept of zonal pricing and its application in the single European electricity market through the CACM guideline, as well as the impacts that multiple bidding zones in GB could have on the CfD mechanism and on investment in generation. This thesis discusses the case in which Scotland is a separate price zone to the rest of GB, and the potential impacts on the investment and dispatch of generation. Currently, GB is a single, separate bidding zone within the single European electricity market. Scotland becoming a separate price zone could be the result of a bidding zone review concluding that capacity allocation is necessary within GB, due to the frequent occurrence of congestion between Scotland and rGB. It is not possible at this stage to comment on the likelihood of this in the future, especially with the additional complication of Brexit and the future place GB could take within the SEEM. However, the incidence of congestion between Scotland and the rest of GB has been discussed and has resulted in various improvements to the transmission network within GB in recent years, including the development of sub-sea HVDC ‘bootstrap’ links between Scotland and rGB [130]. With continued development of renewables in Scotland and much of the conventional generation due to retire over the next decade it is conceivable that this boundary could become constrained more frequently, as the higher proportion of intermittent generation in Scotland is exported in periods of high wind resource and Scotland is left dependent on importing from rGB at times of low wind resource. As set out in the CACM, bidding zones have to be reviewed every two years, so it is possible that at some point the prospect of Scotland becoming a separate bidding zone to rGB would be a rational one. It has been seen in the case of Germany and Austria that ACER will order the splitting of zones even when the states concerned do not agree that it is in their best interest [132].

Due to the higher wind resource in Scotland, especially in the northern regions and offshore, wind turbines have consistently higher capacity factors and thus lower levelised costs. This means that utilising Scottish wind generation could be the most cost-effective way of meeting the UKs carbon and renewables targets. The introduction of multiple price zones in GB could disincentivise development in Scottish renewable capacity if it results in Scottish generators gaining less overall revenues than generators in the rest of GB due to the introduction of zonal CfD strike prices.

Chapter 4.

Investment Modelling in a low carbon world

The development of reliable power systems models is essential to power systems engineers and policy makers, to ensure the continued efficient operation of the electricity network and to predict the effectiveness of policy tools in meeting government targets, for example to encourage low carbon generation. The spatial and temporal complexity of such models varies with the scope of the analysis. In general, short-term models with high spatial resolution are used to ensure that power system operation occurs within the limits specified in the network codes [133] and long-term models with lower spatial resolution are used for system planning and for the prediction of investment patterns [134].

This work focuses on investment in low carbon generation in the long term (over a matter of years) and the impacts that various market pricing and subsidy scenarios have on such investment. As such, this chapter will explore the literature available on long term investment modelling and compare the current modelling styles and methods in use before going on to describe the modelling framework and models used in this work.

4.1. Forms of investment modelling

Power systems optimisation models are used for the purpose of finding the most cost-efficient solution for the future generation mix. Many of these models optimise the total costs of installed capacity and dispatch over the modelled time horizon to meet a set demand profile, subject to various constraints used to represent the operational limits of the power system. Investment decisions are based on capital and operational costs, future demand and the potential for dispatch based on generation and system constraints. Model inputs depend on the adopted modelling approach and can include the capital and operational costs of different types of generation, generator availabilities and demand profiles over the model time horizon. The objective function can be set to minimise all costs, maximise profit to generators or maximise social welfare (consumer surplus plus producer surplus). Such models also use constraints to more accurately represent the operation of the power system, for example constraints to represent the transmission system, Kirchhoff’s laws, generator availability, system security constraints and the requirement for instantaneous demand-supply matching. Demand is often represented by load curves and generation dispatch can be represented by technology-specific generation profiles. Future costs are discounted to Net Present Value (NPV) by use of a discount rate to represent the results in terms of present day prices.

Cost minimisation models are thought to represent an idealised system for consumers, in which generation bids into energy markets at its short run costs and the markets clear with the cheapest generation meeting demand at each time step in the demand profile. This assumes perfect competition without significant market power, a commonly used assumption in investment modelling [135]. Profits occur to generators whose short-run costs are less than the clearing price, and these profits are used to cover project development and capital costs [136]. Profit maximisation models represent an ideal system for producers, where the generation projects chosen to be built will guarantee the highest net profit to the producer. Such models are a continuation of cost minimisation, as generation projects with the lowest costs will be those most likely to gain the highest profits.

Many examples of long term investment modelling have been found in the literature. The recent focus of such work has often been the prediction of the ideal generation mix to meet carbon reduction targets. Fursch et al at Cologne Institute for Energy Economics (EWI) used DIMENSION to model twenty-seven countries in Europe with interconnection to northern Africa at five year timesteps until 2050, to investigate the least cost European electricity mix for meeting European targets of 80% reduction of CO_2 and 80% of electricity generation from renewables by 2050 [137]. Different levels of interconnector development throughout Europe were also investigated, leading to the conclusion that increased levels of interconnection capacity within Europe led to additional cost savings of €57billion due to the utilisation of the best European renewable sites.

Scenario comparison is a popular method to investigate how carbon reduction targets can be met in a cost-effective manner. AF Mercados Consulting have developed Ordena Plus, a long term investment and electricity market dispatch simulation model, minimising capital and operational costs of capacity and generation. In a representation of GB from 2011 to 2050 they created three scenarios, one with no carbon or renewable targets, one with carbon targets from the CCC and one with both carbon targets and 2020 renewables targets [138]. They found that the 2050 carbon targets can be met by nuclear and CCS more cheaply than with renewables. However, they do not discuss the spatial resolution of the model, or the inclusion of transmission constraints between nodes, and specifically do not include policy instruments impacting on the investment in low carbon technologies such as the ETS, EPS, climate change levy or subsidies to renewable generators. Another example of scenario comparison is the use of COMPETES by Oxdemir et al to compare the cost effectiveness of various renewable support policy scenarios for the EU system in 2030 [139]. Renewable support mechanisms investigated included those focused on subsidising renewable energy production and those focused on encouraging renewable generation capacity. They found that the most cost effective way of supporting the maximum amount of renewable energy generation is through subsidies directly related to energy output.

The increasing penetration of stochastic renewable generation has resulted in various modelling challenges in recent years. Nagl et al used a stochastic investment and dispatch cost minimisation model to represent various renewable generation targets in Europe by 2050 [140]. By including various stochastic feed-in scenarios for solar and wind generation it was found that more dispatchable generation such as biomass and geothermal were installed to a much greater extent in the high-RES scenarios. They claim that deterministic models underestimate the impact of intermittent renewables and over-invest in technologies such as wind power. The European Model for Power System Investment with (high shares of) Renewable Energy (EMPIRE) is another example of a model which focuses on representing the stochasticity of renewable generation by making investment decisions over both long term and short term timescales, subject to operational uncertainty [141]. The spatial variation of the wind resource is also challenging to include in investment modelling, as wind speed is very dependent on local geographical features. Neuhoff et al made use of the Integrated Planning Model (IPM) to develop a methodology to model the spatial variation in wind output in a seven-area representation of GB complete with transmission constraints [142]. Twenty-four sites of wind data were used as the discounted system cost of investment decisions in coal, gas and wind is minimised over five year time steps.

Twenty-four example power system optimisation models from the literature have been selected to give an idea of the range of capability of this modelling style. This is an inexhaustive list, as a great number of models have been used in the literature and are constantly being adapted and created for specific studies. Those presented here have been chosen with the purpose of illustrating models specifically focusing on long term investment of low carbon generation within the power sector. It should be noted that this review focuses on models which are designed to or have the ability to specifically model electricity demand and supply, rather than all energy systems including heat and transport. As such, well known models which focus on multiple energy vectors such as MARKAL/TIMES, MESSAGE and PRIMES are not discussed. More detailed reviews of energy systems models have been presented by Ringkjøb et al[143], Connolly et al [144] and Hall and Buckley [145].

Themodels described here include those developed by consultancies for commercial use by TSOs and policy makers [138], [139], [142], [146]–[148] and models developed by University research groups [135], [141], [149]–[164] for the purpose of academic research. Examples of commercial models are BID3, which has been adapted for long term market and network constraint modelling by National Grid [165] and Ordena Plus, which has been adapted into the Scottish Electricity Dispatch Model (SEDM) by AF Mercados Consulting for the Scottish

Government with the purpose of understanding how policy decisions can impact on the future investment in generation [166], [167]. Models developed for research purposes range from complex large scale models used by multiple research groups in multiple institutions to simpler solvers developed at a smaller scale for specific individual research outputs. Examples of such large scale models are ELMOD from Dresden University of Technology [135], and DIMENSION from the Institute of Energy Economics in Cologne (EWI) [157]. These are both models of the interconnected European power system with hundreds of nodes, and have been used and adapted for many projects [168]–[170]. Smaller scale models include ELCO, developed by two researchers at the German Institute for Economic Research Berlin (DIW) and the Technical University of Berlin (TU) to investigate the impact that EMR could have on the development of CCS in GB [158] and SWITCH, developed by M. Fripp at the University of California to determine the optimum mix of wind and solar plants within the Californian power system for his PhD thesis [159]. Table 7 displays the models discussed in this literature review, along with their affiliation, type of objective function, spatial resolution and temporal resolution. Objective functions are classed as either cost minimisation or profit maximisation, with the exception of BALMOREL by DTU, which maximises social welfare (consumer surplus plus producer surplus) [161].. These two techniques both have a similar purpose; to find the lowest cost solution for the system, with profit maximisation problems also including profit terms to maximise generator revenues. Cost minimisation is used in system planning to find the lowest system cost for generation, and thus also for consumers as generation costs are passed to the consumer through energy bills. Cost minimisation models are most often used for looking at generation investment and network decisions for a system, for example the use of BID3 by National Grid and the use of DIMENSION to model investment decisions to meet 2050 carbon reduction and renewables targets. Profit maximisation is an extension of cost minimisation, as generator costs must be kept low to maximise profit. Section 4.2.1 shows that a few additional terms can make a cost minimisation objective function into a profit maximisation objective function, as the overall profit for a generator must take account of the costs involved with generation. Profit maximisation tends to be used more often by developers deciding between projects, or researchers deciding on the logical behaviour of developers. Examples include EMELIE, a profit maximisation model developed by the European Commission which has been used to investigate the impact of refunding ETS proceeds to renewable generators [147] and ELCO, a profit maximisation model used to investigated the possible uptake in investment of CCS due to EMR subsidies. MOSSI also uses profit maximisation to simulate investment in generation capacity due to competitive liberal electricity markets, rather than using cost minimisation to represent whole system planning at least cost [171].

The temporal and spatial resolution of these models differs greatly, as shown in Table 7. ELMOD has the highest spatial resolution, using 2120 nodes to represent mainland Europe [135] and the unnamed model from the National University of Colombia has the lowest spatial resolution, representing GB with a single node. Temporal resolution ranges from hourly to annual, with some models splitting the year into several load blocks to represent seasonal or peak/off-peak patterns in demand. Many models with an hourly temporal resolution involve a more detailed representation of unit commitment, including thermal generator ramping rates and minimum up/down time. ELMOD includes cold, warm and hot start-up options and a minimum down time for each plant. Longer term models tend to have less spatial resolution, for example ELCO, which has been run by Mendelevitch and Oei to 2050 using three nodes to represent GB [158].

Table 7 - Investment models from literature review, with affiliation, modelling style, spatial resolution, temporal resolution and reference

Model	Affiliation	Objective function	Spatial resolution	Temporal resolution	Ref
BALMOREL	Technical University of Denmark	Maximisation of social welfare	User defined	User defined	[161]
BID3	Pöyry	cost-minimisation	User defined	User defined, default is hourly	[146]
Calliope	S. Pfenninger & B. Pickering	cost-minimisation or profit maximisation	User defined	User defined	[162]
COMPETES	Energy Research Centre of the Netherlands	cost-minimisation or profit maximisation	Europe (1 node per country)	User defined, from annual to sub-hourly	[139]
DIMENSION	EWI, University of Cologne	cost-minimisation	Europe, 224 nodes	Hourly	[157]
ELCO	DIW Berlin and TU Berlin	profit-maximisation	GB, 3 nodes	5 load blocks per year	[158]
ELMOD	Dresden University of Technology	cost-minimisation	mainland Europe, 2120 nodes	Hourly	[135]
EMILIE	European Commission	profit-maximisation	unspecified	Annual	[147]
EMMA	Neon Energie	cost-minimisation	NW Europe (1 node per country)	Hourly	[163]
EMPIRE	Norwegian University of Science and Technology	cost-minimisation	Europe, 31 nodes	User defined (inter-annual time slices)	[141]
Enertile	Fraunhofer ISI	cost-minimisation	Europe, North Africa and Middle East (1 node per country)	Hourly, to 2050	[164]

Model	Affiliation	Objective function	Spatial resolution	Temporal resolution	Ref
ENTIGRIS	Fraunhofer ISE	cost-minimisation	Europe, North Africa (43 nodes)	Hourly, to 2050	[149]
highRES	University College London	cost-minimisation	GB, 20 nodes	Hourly, over 1 year	[150]
IPM	ICF Consulting	cost-minimisation	GB, 7 nodes	20 load segments per week - 1040 per year	[142]
LIMES-EU	Potsdam Institute for Climate Impact Research	cost-minimisation	Europe, 29 nodes	48 time slices for each year, until 2050	[151]
MOSSI	Imperial College London	Profit-maximisation	GB, 1 node	Hourly, to 2100	[152]
Ordena Plus	AF Mercados consulting	cost-minimisation	Configurable, in this case GB	Annual, split into peak and off-peak demand blocks	[138]
Plexos	Energy Exemplar	cost-minimisation or profit maximisation	configurable up to 10,000 nodes	configurable - 1min to 24hours	[148]
PowerGAMA	SINTEF	cost-minimisation	Configurable	Configurable, default is hourly	[153]
ReEDS	National Renewable Energy Laboratory (NREL)	cost-minimisation	North America (134 nodes)	17 demand blocks representing sequential 2 year periods	[154]
SWITCH	M Fripp PhD Thesis, UC	cost-minimisation	California, 16 nodes	Hourly, 2010-2025	[159]
Unnamed	Universidad Nacional de Colombia	profit-maximisation	GB, single node	Monthly, 2013-2030	[160]
URBS	Technical University of Munich	cost-minimisation	Configurable	Configurable, default is hourly	[155]
WeSIM	Imperial College London	cost-minimisation	Configurable	Configurable, over multiple years	[156]

Policy instruments for carbon reduction such as carbon taxes and subsidies to low carbon generation can be included in investment models. These instruments are used to alter the variable costs of such generators and thus influence the cost optimisation. Carbon reduction targets can be modelled in two ways, both as explicit targets set as a model constraint for maximum carbon production or minimum low carbon generation and as implicit model properties such as additional cost terms to represent carbon taxes or subsidies to low carbon generation. Various studies have been undertaken to compare different policy mechanisms within the literature. One example is ReEDS, which has been used to examine the impacts of a range of existing and proposed energy policies for North America, though in one study utilising ReEDs it is found that focused innovation policy can be just as effective at reducing carbon emissions as focused carbon policies [172].

The investment models from the literature review have different ways of representing carbon reduction policies. Table 8 shows the methods used to represent carbon reduction policy in the investment models previously featured in Table 7. The models use a range of implicit methods, explicit methods or a combination of both explicit and implicit methods for representing carbon reduction targets. Two of the models, DIMENSION and ELMOD, do not represent carbon reduction targets as renewable technologies are not explicitly modelled. Of the models, sixteen use implicit methods, fourteen using carbon pricing to raise the operational costs of carbon producing generation, five using some form of subsidy as a profit term to increase profits to low carbon generators and one using a payment to low carbon generators of a proportion of ETS proceeds. Twelve of the models use explicit methods, including five which also used implicit methods. Ten of these models use explicit carbon emissions targets and seven models use explicit renewable generation targets, with five models able to use both explicit carbon emissions targets and renewable generation targets. Four models can represent a combination of both implicit and explicit carbon reduction policies, namely: BALMOREL, ELCO, ReEDS and URBS.

It can be seen that the modelling style does not necessarily influence the method of representation of carbon reduction targets. Both cost-minimising and profit maximising models use carbon pricing, carbon emissions targets and renewable targets. However, only profit maximisation models use subsidy payments, as cost minimisation models will not include any profit terms.

Table 8 - Investment models from literature review, with modelling style and inclusion of low carbon targets

Modelling Style	Model	Implicit/Explicit Inclusion of low carbon targets	Ref
Max social welfare	BALMOREL	Implicit – carbon pricing, renewable subsidies Explicit – carbon emissions targets, renewables targets	
Cost-minimisation	BID3	Implicit - carbon pricing	[146]
	DIMENSION	No - renewable tech treated exogenously	[157]
	ELMOD	No - wind treated as a reduction in demand	[173]
	EMMA	Implicit – carbon pricing	
	EMPIRE	Implicit – carbon pricing	
	Enertile	Implicit – carbon pricing	
	ENTIGRIS	Explicit – emissions targets and renewables targets	
	highRES	Explicit – emissions targets	
	IPM	Explicit - wind gen target of 40% by 2020	[142]
	LIMES-EU	Explicit – emissions targets and renewables targets	
	Ordena Plus	Explicit - carbon emissions targets for 2050 and renewables targets for 2020	[138]
	PowerGAMA	Implicit – carbon pricing	
	ReEDS	Implicit – carbon pricing Explicit – emissions targets and renewables targets	
	SWITCH	Implicit - carbon pricing	[159]
	URBS	Implicit – carbon pricing Explicit – emissions targets	
	WeSIM	Explicit – emissions targets	
Profit-maximisation and Cost-minimisation	Calliope	Implicit – carbon pricing	
	COMPETES	Implicit – carbon pricing, renewables subsidies Explicit – renewables targets	
	Plexos	Implicit - carbon pricing	[148]
Profit-maximisation	EMILIE	Explicit - Emissions targets (all scenarios) Implicit - proportion of ETS proceeds paid to low carbon generation projects as positive cost term in maximisation (some scenarios)	[147]
	ELCO	Explicit - Annual carbon emissions constraint Implicit - CfD tech receives full strike price in profit	[158]
	MOSSI	Implicit – carbon pricing, renewable subsidies	
	Unnamed	Implicit – carbon pricing, renewable subsidies	[160]

This work focuses on long term investment modelling, using the SEDM and a two node solver. The SEDM has an objective function which minimises the cost of all capital and operational expenditures, whilst including CfD top-up payments as a negative cost term (or 'payment') per

MWh delivered, reducing the operational costs of low carbon generation. None of the models in this literature review was found to use top-up or subsidy payments to lower the levelised cost of generation as is done in the SEDM so that generation receiving a subsidy would have a lower levelised cost relative to generation without a subsidy. The only work found during this literature review representing subsidy payments as negative cost terms in a cost minimisation problem were to represent electricity being sold from microgrids and hybrid renewable systems back to the main power grid [174], [175].

The two node solver objective function has been altered to offer the user a choice between cost minimisation and profit maximisation, with CfD top-up payments included as either positive or negative terms and the option to include wholesale market revenues in the profit maximisation problem. This has been done to compare the results from these modelling styles under the introduction of zonal pricing in GB and to show how the modelling style can ultimately impact on the simulation results. The following sections outline the model objective functions, data sources and the representation of zonal pricing for both the two node solver and the SEDM.

4.2. Two node solver

The two node solver has been created for the purpose of this work: to illustrate the impacts of introducing zonal pricing to a system with CfD subsidy payments. This is done using a simple modelling framework where the model mathematics are simple enough to interpret the results without additional constraints impacting upon their clarity [176].

A two node model has been created to represent GB, in which one node represents Scotland and the other represents the rest of GB (rGB). Demand is split between the two nodes in accordance with the present day demand in the two areas and is modelled as increasing linearly at both nodes over a six year timeframe. It has also been separated into a peak and off-peak block in each year. Candidate generators for investment are included as continuous variables of total installed capacity at each node. Decision variables are the new installed capacity for each year and the dispatch of generation in each demand block. As demand increases in each year of the simulation, there must be an investment in some form of new generation every year in order to meet a total energy balance constraint. The results focus on where the model decides to invest in new generation capacity and what factors influence this decision. Dispatch is included in the cost minimisation, representing perfect competition. Carbon costs for CCGT generation and CfD top-up payments for wind generation are included in all model runs. The use of this model to represent cost minimisation and profit maximisation scenarios is described further in section 4.2.3.

4.2.1. Objective function and constraints

The objective function minimizes the discounted cost of investment and dispatch as follows:

$$\min \sum_{z=1}^{N_z} \sum_{g=1}^{N_g} \sum_{y=1}^{N_y} \sum_{b=1}^{N_b} \frac{1}{(1+r)^{y-1}} (Capex_{g,y}.NIC_{g,y} + Omfix_g.TIC_{g,y}$$
$$+ (Om\,\mathrm{var}_{g,b} + FC_{g,y,b} + CC_{g,y,b}).Gen_{z,g,y,b}) \tag{1}$$

Where N_z is the number of zones z, N_g is the number of types of generation g, N_y is the number of simulated years y, N_b is the number of demand blocks b, r is the discount rate, $Capex_{g,y}$ is the capital cost of each generation type in each year in £/MW, $NIC_{g,y}$ is the new installed capacity associated with installing each type of generation in each year in MW, $Omfix_g$ is the annual operation and maintenance fixed cost of each type of generation in £/MW/year, $TIC_{g,y}$ is the total installed capacity of each type of generation in each year in MW, $Om\,\mathrm{var}_{g,b}$ is the variable operation and maintenance costs for each generator in each block in £/MWh, $FC_{g,y,b}$ is the fuel costs for each type of generation in each year and block £/MWh, $CC_{g,y.b}$ is the carbon costs for each type of generation in each year and block in £/MWh and $Gen_{z,g,y,b}$ is the dispatched generation of each generator in each zone, year and block in MWh. A table of all notation used in this work can be found on page 15.

In this particular model set-up there are two zones (Scotland and rGB), two types of generation (wind and CCGT), two demand blocks (short peak and long off-peak) and six model years, as the maximum number of constraints using an excel solver was a limiting factor.

The following constraints are applied, representing that the generation in each block and year must not exceed each generator's maximum capacity factor (2), that generation in all blocks and years must meet demand in all blocks and years (3) and that the generation at the Scottish node and rGB node in each block and year must not be greater than the node demand in each block and year plus the export transfer capacity (4):

$$Gen_{g,y,b} \le MCF_g.t_b.TIC_{g,y} \tag{2}$$

$$\sum_{g=1}^{N_g} Gen_{g,y,b} = Dem_{y,b} \tag{3}$$

$$Gen_{z,y,b} \leq Dem_{z,y,b} + PTC_{y,b} \tag{4}$$

where MCF_g is the maximum capacity factor for each type of generation, t_b is the time period of the demand block in hours, $Dem_{y,b}$ is the demand in each year and block in MW and $PTC_{y,b}$ is the transfer capacity limit in each year and block in MW.

To represent a scenario without transmission constraints $PTC_{y,b}$ is set to an arbitrary number higher than total model demand (10^6).

Capital costs are discounted using the ratio of annuity factors shown in (5)-(7) to take account of the model time horizon of six years, assuming a generator economic lifetime of twenty-five years.

$$Capex_{g,y} = TCapex_g \frac{AnnAmort}{AnnM_y} \tag{5}$$

$$AnnAmort = \frac{r(1+r)^{amort-1}}{(1+r)^{amort} - 1} \tag{6}$$

$$AnnM_y = \frac{r(1+r)^{yrem-1}}{(1+r)^{yrem} - 1} \tag{7}$$

where $TCapex_g$ is the total capital expenditure for each type of generation, before annuity factor adjustment, in £/MW, $AnnAmort$ is the annuity factor for amortization time, $AnnM_y$ is the annuity factor for model lifetime, based on the year of investment, $amort$ is the amortization time in years and $yrem$ is the remaining model lifetime in years.

Subsidies and revenues are included in the objective function as variable costs, dependent on the dispatch of generation. Depending on if the model set-up is for a cost minimisation or profit maximisation problem, subsidies (in the form of CfD top-up payments) are included as either a positive or negative cost term, with wholesale revenues included as negative cost terms in the profit maximisation model runs. The objective function including subsidy and revenue payments for the cost minimisation model set up is shown in (8) and for the profit maximisation model setup is shown in (9).

$$\min \sum_{z=1}^{N_z}\sum_{g=1}^{N_g}\sum_{y=1}^{N_y}\sum_{b=1}^{N_b}\frac{1}{(1+r)^{y-1}}(Capex_{g,y}.NIC_{g,y}+Omfix_g.TIC_{g,y}$$
$$+(Om\operatorname{var}_{g,b}+FC_{g,y,b}+CC_{g,y,b}+Subs_{z,g,y,b}).Gen_{z,g,y,b}) \quad \textbf{(8)}$$

$$\min \sum_{z=1}^{N_z}\sum_{g=1}^{N_g}\sum_{y=1}^{N_y}\sum_{b=1}^{N_b}\frac{1}{(1+r)^{y-1}}(Capex_{g,y}.NIC_{g,y}+Omfix_g.TIC_{g,y}$$
$$+(Om\operatorname{var}_{g,b}+FC_{g,y,b}+CC_{g,y,b}-Subs_{z,g,y,b}-\mathrm{Re}v_{z,y,b}).Gen_{z,g,y,b}) \quad (9)$$

where $Subs_{z,g,y,b}$ is the CfD subsidy (top up payment) for each type of generation in each zone, year and block in £/MWh and $\mathrm{Re}v_{z,y,b}$ is the market revenues, represented by the short run marginal cost in each zone, year and block in £/MWh.

In (9) if subsidy and revenue costs are greater than capital and operational costs for a generator then the overall lifetime cost will be negative, i.e. in profit. Maximum profit here is represented by a minimisation of generator income, with generator costs as positive terms and income as negative terms. Profit maximisation models more commonly use a maximisation of income, with costs entered as negative terms [147]. This is the same problem mathematically and in this case the modelling has been done to directly compare with the methods used in the SEDM.

The CfD top-up payment is calculated as the difference between the strike price and the reference price (10), the latter of which is assumed to be the annual average short run marginal cost (SRMC). As the SRMC is an output of the model, but also an input of the top-up payment calculation, the model has to be run several times and iterated until the SRMC output from the model results matches the input SRMC, from a start point assuming that CCGT is the marginal generator in both zones. The SRMC is calculated in (11) as the short-run costs (fuel, carbon costs and variable operational costs) of the marginal generator for each block, time averaged (12). For zonal scenarios when congestion is present, separate zonal SRMC's are calculated. For base case scenarios without zonal pricing, and for zonal scenarios when congestion is not present, a model-wide SRMC is calculated.

$$Subs_{z,g,y} = StrikeP_g - SRMC_{z,y} \quad (10)$$

$$SRMC_{z,y} = \frac{\max(SRC_{z,g,y,b_1}).t_{b_1} + \max(SRC_{z,g,y,b_2}).t_{b_2}}{(t_{b_1} + t_{b_2})} \quad (11)$$

$$SRC_{z,g,y,b_\#} = Om\,\mathrm{var}_{g,y,b} + FC_{g,y,b} + CC_{g,y,b} \quad (12)$$

where $StrikeP_g$ is the strike price for each type of generation in £/MWh, $SRMC_{z,y}$ is the short run marginal cost in each zone and year in £/MWh, $SRC_{z,g,y,b_\#}$ is the short run cost of each type of generation in each zone, year and specified block in £/MWh.

A representation of the LCF budget is included in the model as an equality constraint to the total subsidy spend, where the total top-up payments to all generators in all years must meet the overall LCF limit figure, as shown in (13). This is to ensure that the generation mix corresponds to GB policy.

$$\sum_{z=1}^{N_z}\sum_{g=1}^{N_g}\sum_{y=1}^{N_y} Subs_{z,g,y} = LCF_{\lim} \quad (13)$$

4.2.2. Data sources

Table 9 lists the data inputs to the model, with sources where appropriate. Model results described in the following sections come from this input data unless explicitly described otherwise, for example Section 5.3.2 has a higher transfer capacity to take account of the Western HVDC Link. All costs are discounted to the first year of simulation using a discount rate of 6.5%. This discount rate was chosen to be consistent with the SEDM.

Input figures for capital costs (CAPEX) and operational costs (OMfix, OMvar) come from DECC's Electricity Generation Costs report 2013 [177], converted from 2012 to 2015 prices using the appropriate GDP deflator [178]. CAPEX figures have an additional cost added to the DECC figure to represent technology-specific hurdle rates, calculated from the difference between the model (social) discount rate and the technology-specific discount rate, also from the Electricity Generation Costs report. Total capital cost figures prior to annuity factor discounting (Total CAPEX) are given in Table 9**Error! Reference source not found.** in addition to example values for year 1 and year 6, calculated using equations (5)-(7) (Model CAPEX).

The carbon price is set to the current cap of £18/tCO_2 [179], converted to £/MWh in the model using an emissions factor of 0.451 [180]. It should be noted that this fails to account for the EU ETS price, which at the time of undertaking the analysis was very low, but has since risen to over €29/tCO_2 in 2019 [181]. Fuel prices come from DECC's Energy and Emissions projections from 2015-2020 [182] and are shown only for year 1 and 6, following a linear relationship over the six years.

Table 9 - Data included in the two bus model

	Year 1	**Year 6**	**Source**
Total CAPEX wind (£/MW)	1,802,905		[177]
Model CAPEX wind (£/MW)	824,642	155,245	[177]
Total CAPEX CCGT (£/MW)	612,370		[177]
Model CAPEX CCGT(£/MW)	280,096	52,730	[177]
Hurdle rate wind	0.079		[177]
Hurdle rate CCGT	0.075		[177]
OMfix wind (£/MW)	25220		[177]
OMfix CCGT (£/MW)	42166		[177]
OMvar wind (£/MWh)	0.105		[177]
OMvar CCGT (£/MWh)	5.26		[177]
Carbon price (£/tCO_2)	18		[179]
Fuel price CCGT (£/MWh)	19.04	20.97	[183]
Strike Price wind (£/MWh)	104.4		-
Net thermal efficiency CCGT	0.53		[180]
Max capacity factor CCGT	0.8		-
Max capacity factor wind Sco	0.3		-
Max capacity factor wind rGB	0.25		-
Discount rate	0.065		[180]
Demand rGB (GW)	31.82	34.16	[182]
Demand Scotland (GW)	3.18	3.42	[182]
Net transfer capacity (GW)	3.3		[130]
LCF constraint (billion £)	37.9		[6]

CfD strike prices were assumed at the levelised cost of wind technology in rGB, calculated over the seven year timeframe using model input data. The levelised cost of energy is represented by the following formula:

$$LCOE = \frac{NPV\ of\ total\ costs}{NPV\ of\ electricity\ generation} = \frac{\sum_{t=1}^{n}\left(\frac{Cap_t + Op_t + Fu_t + Em_t}{(1+r)^t}\right)}{\sum_{t=1}^{n}\left(\frac{Gen}{(1+r)^t}\right)} \tag{14}$$

in which *LCOE* is the levelised cost of energy, *t* is the year at which investment occurs, *n* is the expected lifetime of the power station, Cap_t is the capital costs in the year *t*, Op_t is the operational costs in the year *t*, Fu_t is the fuel costs in the year *t*, Em_t is the emissions costs in the year *t*, Gen_t is the electrical energy generated in the year *t* and *r* is the model discount rate (6.5%).

Maximum capacity factors were assumed to be higher for wind generation in Scotland, at 30% compared with 25% in rGB. It should be noted that these are example values intended to illustrate higher capacity factors for wind generation in Scotland. Maximum capacity factors for CCGT were assumed to be the same in Scotland and rGB, at 80%. The availability of the generators is simply represented by these capacity factors in the annual resolution, i.e. plant closures and time-dependent wind resource are not explicitly modelled.

Example demand values were used in Scotland and rGB, also linearly rising between years 1 and 6, with Scottish demand assumed to be 10% of demand in rGB as in the SEDM. This assumption is consistent with a detailed analysis of multiple years of historical demand data undertaken by Staffell and Pfenninger [184]. Year 1 demand figures are based on 2014 figures from DECC demand projections [182], altered to include additional demand due to energy industry use [51], transmission losses as a percentage of final consumption [51] and exclude the percentage of total UK consumption from Northern Ireland [185] as in the SEDM [180].

Available transfer capacity between Scotland and rGB is from the B6 boundary line capacity figures in National Grid's Electricity Ten-Year Statement [130], altered in Section 5.3.2 to account for an additional 2.2GW of transmission capacity from the Western HVDC Link.

The Levy Control Framework spending cap has been set as the total sum of the annual figures produced until 2020 without the 20% headroom [6], also converted to 2014 prices using the appropriate deflator [178]. Section 1 illustrates a case with the 20% headroom included.

4.2.3. Representation of zonal pricing scenarios

The two node solver has been used to represent the zonal pricing scenarios described in Chapter 3, by means of altering the 'Subs' term in the objective function depending on the scenario being modelled.

1) Base Case - Low Carbon Subsidies

The base case scenario represents the current GB system in which there is no zonal split in GB and it continues to trade as a single zone in the Single European Electricity Market. As such, energy trading occurs without impacts due to transmission constraints in the network and so the solver is run without any constraints included due to net transfer capacity limits, i.e. the transfer capacity in (4) is set to a number higher than model demand. This scenario includes both the carbon price and low carbon subsidies that currently exist in GB as part of

EMR. Subsidies are represented by CfD top-up payments, which are the difference between the strike price for wind generation and the GB-wide short run marginal cost in each model year, shown in (15):

$$Subs_{g,y} = StrikeP_g - SRMC_y \tag{15}$$

where $StrikeP_g$ is the model-wide strike price for wind generation and $SRMC_y$ is the model-wide short run marginal cost in each model year. The model-wide strike price for wind generation is assumed to be the levelised cost of energy for wind generation, calculated as in (13).

2) Zonal Scenarios – GB Strike Price and Zonal Strike Price

These scenarios represent the introduction of zonal pricing to GB, as described previously in section 3.3.2. Zonal pricing, with Scotland as a separate price zone to the rest of GB, involves separate market clearing prices for both zones at times of network congestion. As such, for these scenarios the transfer capacity in (4) is set to the transfer capacity at the border (National Grid B6 boundary) between Scotland and rGB.

The GB strike price scenario includes CfD top-up payments to a set GB strike price for all low carbon generation, even in the case of different zonal prices in Scotland and rGB. In this case, if the transmission constraint is met then the top-up payments to generation in each zone will differ based on the zonal SRMCs, as shown in (16):

$$Subs_{z,g,y} = StrikeP_g - SRMC_{z,y} \tag{16}$$

where $SRMC_{z,y}$ is the zonal SRMC in each model year.

The zonal strike price scenario involves separate zonal strike prices in Scotland and rGB, based on the zonal LCOE calculated based on the separate zonal capacity factors. As such, the top-up is calculated by the difference between the zonal strike price for wind generation and the zonal marginal price, shown in (17):

$$Subs_{z,g,y} = StrikeP_{z,g} - SRMCrGB_{z,y} \tag{17}$$

where is the zonal strike price for wind generation and is the zonal SRMC in each model year.

4.3. The Scottish Electricity Dispatch model

The Scottish Electricity Dispatch Model (SEDM) has been created for the Scottish Government by Mercados from a sophisticated, established, professionally developed existing electricity market dispatch and investment tool known as ORDENA plus, which has been used in research in multiple countries worldwide [138], [186]–[188]. It is a mixed integer linear programme written in the Xpress Mosel language using a FICO Xpress solver [189]. The model comprises two modules – long term planning and short term unit commitment. The long term module objective function minimises the total cost of the system NPV in order to meet the demand specified in the model. The short term module takes the long term installed capacity results for a selected year and season as an input and optimises dispatch for minimal operational costs, solving the unit commitment problem in half-hourly increments over a one week time period. This work will focus on the long term planning module only.

The SEDM comprises of fourteen nodes representing GB, shown in Figure 15. The fourteen nodes were chosen using the National Grid Seven Year Statement boundaries [190] (shown in pink) to represent those boundaries most relevant to studies concerning Scotland, with ten nodes representing Scotland and four representing England and Wales. Each node has associated generation, demand and transmission capacity to other nodes based on present day GB system capacity, as well as a set of candidate future generation and transmission developments. Planned generation entry years have been input for projects currently in construction and retirement dates have been input where publically announced by the developer. In the long term investment module additional investment in generation is selected from a portfolio of candidate projects. To differentiate the risk associated with development of different technologies, technology-specific discount rates are used in addition to the overall discount rate. The utilisation of generation is modelled annually, with demand represented using blocked load duration curves and with a merit order stack created using generation variable costs i.e assuming perfect competition. Kirchhoff's first law is input as a model constraint to represent power flows on the transmission network. Demand-supply balance is maintained by a very high cost associated with energy not served.

The SEDM is a complex, professionally developed and validated existing tool which has been adapted, as far as possible and in an original way, to address the questions raised in this thesis. The following sections go on to describe the long term model in more detail, along with the updates and validation undertaken for this work. A discussion of the limitations of dispatch modelling in this manner can be found in section 6.3.3. All figures and equations in these sections have been adapted from the model design document to represent the use of the SEDM in this work [180].

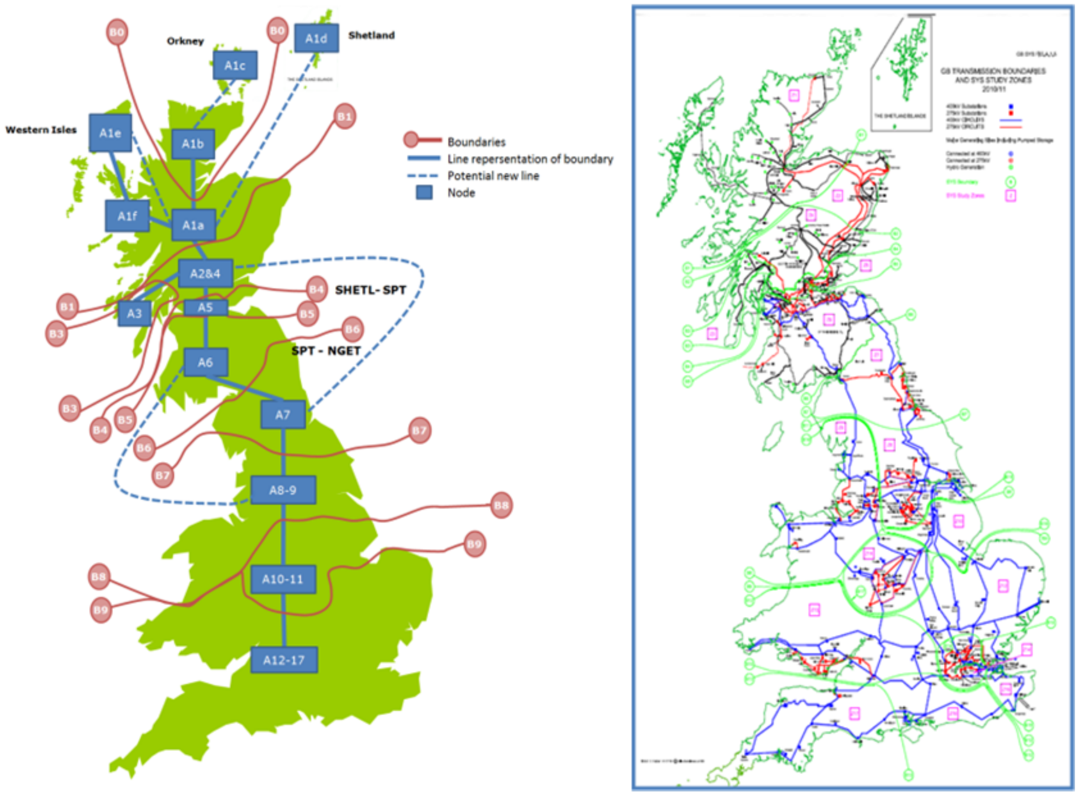


Figure 15 - Model Representation of GB (left) compared with transmission network (right), from the model design document [180]

4.3.1. Objective function and constraints

The long term model objective function minimises the Net Present Value (NPV) of total system costs over a user-defined planning period whilst meeting the model constraints. System costs are comprised of investments in new generation and transmission, the cost of dispatch including fuel and O&M costs, the cost of system reliability standards such as the value of lost load and any externalities that may result in costs, such as carbon pricing, low-carbon subsidies and technology-specific investment limits set by the user. Inputs to the long term model are existing, planned and candidate generation, annual demand, existing, planned and candidate transmission capacity, generation costs, capital and operational costs, fuel prices, transmission costs and any applicable constraints. Model outputs include installed capacity, dispatch, carbon emissions, zonal marginal prices and total costs for each model year.

The long term model objective function is shown in (18):

$$\min \sum_{p=1}^{1} \frac{1}{(1+r)^{p-1}} \left(\sum_{g} (CV_{p,g} + CF_{p,g} + IC_{p,g}) + \sum_{d} (CV_{p,d} + CF_{p,d} + IC_{p,d}\right) \qquad (18)$$

$$+\sum_{l}(CV_{p,l}+CF_{p,l}+IC_{p,l}))$$

where p signifies the period over which the calculation takes place, r is the discount rate, CV is the total variable costs, CF is the fixed O&M costs and IC is the total investment costs. The suffix g indicates generation (e.g. production, fixed operating and expansion costs), the suffix d indicates demand (e.g. demand side response and unserved energy costs) and the suffix l indicates transmission (e.g. congestion and investment costs). All costs are in NPV for 2014, discounted by a user-defined social discount rate.

As with the two node solver, total investment costs are averaged annually over the lifetime of the plant, discounted to present value. This means that if a plant is built with a twenty-five year lifetime, generation built five years before the end of the simulation the total investment cost will not consider the remaining twenty years of costs. This is described in the following formulae:

$$IC_{g,p} = Int_{g,r}\,\frac{AnnLife_g}{Ann\,\mathrm{Re}\,m_{g,p}}.\left(CAPEX_g + AdCAPEX_g\right).inv_{g,p} \tag{19}$$

$$Int_g = \frac{1}{Const_g}.\sum_{i=0}^{Const_g-1}(1+r)^{Const_g-i} \tag{20}$$

$$AnnLife_g = \frac{r.(1+r)^{Amort_g-1}}{(1+r)^{Amort_g}-1} \tag{21}$$

$$Ann\,\mathrm{Re}\,m_{g,p} = \frac{r.(1+r)^{\mathrm{Re}\,m_{g,p}-1}}{(1+r)^{\mathrm{Re}\,m_{g,p}}-1} \tag{22}$$

where $Int_{g,r}$ represents the interest accumulated, $AnnLife_g$ is the annuity factor of economic lifetime, $AnnRem_{g,p}$ is the annuity factor of the shortened generation period until the end of the simulation, $CAPEX_g$ is the capital expenditure in £/MW, $inv_{g,p}$ is the volume of investment in MW, $Const_g$ is the construction time of generator g, r is the model discount rate, $Amort_g$ is the amortization time of generator g and $Rem_{g,p}$ is the remaining years operation of generator g that fall within the model lifetime in period p.

Variable costs for generation are shown in (23).

$$CV_{p,g} = \sum_{b\in e\in p}(Dur_b \cdot gt_{g,b} \cdot (VarO\&M_g - EnPay_{g,p}$$

$$+\sum_{f} fuel_{g,f,b} \cdot FuelCost_{f,e} + \sum_{po}\sum_{g\subset z} emi_{g,po,b} \cdot EmiCost_{z,po,e})$$
(23)

where $CV_{p,g}$ is the generation variable operating cost, Dur_b is the duration of load block b, $gt_{g,b}$ is the net power generation of generating unit g in block b, $VarO\&M_g$ are the variable operation and maintenance costs of unit g, $EnPay_{g,p}$ is the energy payment or subsidy for unit g in period p, $fuel_{g,f,b}$ is the fuel consumption of unit g of fuel type f in block $b,$ $FuelCost_{f,e}$ is the cost of fuel f in stage $e,$ $emi_{t,po,b}$ is the emissions of unit g of pollutant po in load block b and $EmiCost_{z,po,e}$ is the emissions cost in free flow zone z for pollutant po in stage e.

$EnPay_{g,p}$ is used to represent CfD top-up payments as a negative cost term, reducing the variable cost of the appropriate generator by the CfD top-up. This top-up is calculated as the difference between the generator-specific strike price and the annual SRMC, representing the wholesale price of electricity. This is shown in (24). As the SRMC is an output of the model, but also an input to of the top-up calculation, the model has to be run several times and iterated until the output SRMC matches the input SRMC.

$$EnPay_{g,p} = StrikeP_g - SRMC_p \tag{24}$$

Fixed costs, $CF_{p,g}$, are dependent on the input fixed operation and maintenance costs of unit g over the model lifetime. These fixed costs are shown in (25).

$$CF_{p,g} = \frac{\sum_{b\in e}\left(G\max_{g,e} .Dur_b\right)}{\sum_{b} Dur_b} .OMfix_g \tag{25}$$

where $G\max_{g,e}$ is the installed capacity of generator *g* in stage *e* in MW and $OMfix_g$ is the fixed operation and maintenance costs of unit *g*.

The model has various constraints, some of which are subject to user inputs. The energy balance constraint is used to ensure that generation at a node and imports from other nodes meet demand at a node, allowing for energy not served. This is shown in (26).

$$\sum_{g\in i} gt_{g,b} + \sum_{l}\sum_{j} f_{j,i,l,b}$$
(26)

$$= \sum_{j} f_{i,j,l,b} + \sum_{d \in i} (dem_{d,i,b} - ens_{d,i,b}) + \sum_{r \in i} gp_{g,b} + sur_{i,b}$$

where $gt_{g,b}$ is the generation of unit g in block b, $f_{j,i,l,b}$ is the power flow on line l from node j to node i in block b, $f_{i,j,l,b}$ is the power flow on line l from node i to node j in block b, $dem_{d,i,b}$ is the demand at node i in block b, $ens_{d,i,b}$ is the non-supplied energy in node i in block b, $gp_{g,b}$ is the pump storage consumption of unit g in block b and $sur_{i,b}$ is the surplus power generation at node i in block b. The surplus power generation term allows generation to be "constrained off" at each node. Generation $gt_{g,b}$ is also limited by generator availability factors intended to represent plant outages and renewable generation is limited by maximum capacity factors based on resource availability. There is a high cost associated with energy not served (£30,000/MWh) intended to discourage this option in the cost minimisation.

Line capacity limits can be set by the user, and are constrained by a maximum flow term (27):

$$f_{i,j,l,b} \leq f\max_{i,j,l} \tag{27}$$

where $f\max_{i,j,l}$ is the maximum flow for line l. Maximum flows from node i to node j and from node j to node i can be defined separately. To represent an unconstrained model, $f\max_{i,j,l}$ is set to a value greater than model demand so that the constraint is never active (10^6). Transmission losses are represented by an overall increase in demand, and so are not dealt with explicitly in the model constraints.

The resource availability constraint is used to ensure that generation does not exceed its defined availability in any demand block, as shown in (28)-(29):

$$gt_{g,b} \leq AF_{g,b} \cdot G\max_{g,e} \tag{28}$$

$$gt_{g,b} \geq AF\min_{g,b} \cdot G\max_{g,e} \tag{29}$$

where $AF_{g,b}$ is the maximum availability factor for generator g in block b and $AF\min_{g,b}$ is the minimum availability factor for generator g in block b.

There is an optional security constraint to ensure system adequacy, ensuring the de-rated plant capacity margin meets peak demand plus a user-defined additional security margin, shown in (30):

$$\sum_{g=1}^{G}(gMax_g \cdot \mu_g) \geq \overline{dem}_{a,p} \cdot (1+\varepsilon_{a,p}) \tag{30}$$

where $gMax_g$ is the maximum investment (MW) in generator g, μ_g is the peak contribution of generator g, $\overline{dem}_{a,p}$ is the peak demand in period p and $\varepsilon_{a,p}$ is the user-input security reserve factor of area a in period p.

Model-wide investment limits were included to produce model results that better represent the limitations of the current GB system, for example all of the investment in generation cannot happen in a single model year. Two investment limit constraints were included, one limiting the total monetary investment allowed in a given year (31), and one limiting the total investment in capacity allowed in a given year (32):

$$\sum_{g\subset a} inv_{g,p} \leq MaxExp_{a,p} \tag{31}$$

$$\sum_{g\subset a} inv_{g,p} \cdot CAPEX_g \leq MaxInv_{a,p} \tag{32}$$

where $inv_{g,p}$ is the investment in capacity (MW) of generator g in period p, $MaxExp_{a,p}$ is the maximum capacity expansion (MW) allowed in area a in period p, $CAPEX_g$ is the capital cost of generator g and $MaxInv_{a,p}$ is the maximum investment (£) allowed in area a in period p.

In addition to the model-wide investment limits there are also technology-specific investment and generation limits, so that the model produces a suitably diverse generation mix. For example all of the investment in generation in a certain model year cannot come from a single technology type due to supply chain limitations. Two types of technology-specific limits are included, one limiting the annual power generation for each technology type (33),(34) and one limiting the investment in installed capacity for each technology type (35),(36). Annual power generation is limited to represent limitations on coal generation due to the LCPD and biomass generation due to the supply of biomass fuel. All other technologies have a limitation on the investment in installed capacity so that the model does not install any one type of generation in a model year to an excessive degree.

$$\sum_{\substack{g \subset tech \\ b \in p}} g_{g,b} \cdot Dur_b \leq EMax_{tech,p} \tag{33}$$

$$\sum_{\substack{g \subset tech \\ b \in p}} g_{g,b} \cdot Dur_b \geq EMin_{tech,p} \tag{34}$$

$$exists_{g,e} \leq GMax_{\ tech,p} \tag{35}$$

$$exists_{g,e} \geq GMin_{\ tech,p} \tag{36}$$

Where $g_{g,b}$ is the generation of generator g in block b, Dur_b is the duration of block b, $EMax_{\ tech,p}$ is the maximum annual power generation of technology *tech* in period p, $EMin_{\ tech,p}$ is the minimum annual power generation of technology *tech* in period p, $exists_{g,e}$ is the existing installed capacity of generator g in stage e, $GMax_{\ tech,p}$ is the maximum installed capacity of technology *tech* in period p and $GMin_{\ tech,p}$ is the minimum installed capacity of technology *tech* in period p.

Annual emissions targets can also be set as an explicit model constraint (37).

$$\sum_{g \subset z, b \in p} emi_{g,po,b} \leq EmiLimit_{z,po,p} \tag{37}$$

Where $EmiLimit_{z,po,p}$ is the maximum emissions of pollutant *po* in free flow zone *z* in period *p* and the calculation of emissions $emi_{g,po,b}$ is shown in (38).

$$emi_{g,po,b} = \sum_{f} fuel_{g,f,b} . FEmi_{g,f,po} \tag{38}$$

Where $FEmi_{g,f,po}$ is the emissions factor of generator *g* for fuel type *f* and pollutant *po* and $fuel_{g,f,b}$ is the fuel consumption of generator *g* of fuel type *f* in load block *b*.

Other user-defined constraints include renewable energy targets, but these are not featured in this work. The LCF was also an optional constraint for the SEDM but had been added in to the model post-validation and had not been verified. Instead, the model results will be compared to the published LCF values in section 7.1.3.

4.3.2. Representation of carbon reduction policy scenarios

A number of policy tools have been used historically in order to encourage the decarbonisation of power systems. These include direct, legally enforceable limits on emissions, emissions taxes and subsidy support for low carbon generation. The SEDM has the ability to model each of these concurrently or separately. In order to study the potential effectiveness of each of these policies on meeting decarbonisation and renewables targets, three scenarios were run:

1) Contracts for difference

A scenario with no policy intervention except the existing low carbon subsidy regime. This can be represented as an objective function with no additional costs or constraints due to emissions, and subsidies modelled as negative costs, as shown as $EnPay_{g,p}$ in (23), with $EmiCost_{z,po,e}$ set to zero.

2) Carbon Pricing

A carbon pricing scenario in which existing subsidies for low carbon generators are complemented with carbon pricing figures taken from the carbon price floor set out in the UK budget at £70/tCO_2 in 2030 [191], increasing linearly from the £18/tCO_2 cap in 2020 [192]. This can be represented with an objective function including additional operational costs due to carbon pricing, as shown in shown in (23), with $EmiCost_{z,po,e}$ used to represent these carbon pricing figures.

3) Emissions Limits

Carbon pricing and low carbon subsidies are combined with strict emissions limits from 2030 onwards based on input from the Committee on Climate Change (CCC) carbon budgets for GB, in which emissions from power stations are 16MtCO_2 by 2030, with a linear reduction to 5MtCO_2 by 2050 [179]. This can be represented with an objective function including emissions costs due to carbon pricing (used to limit emissions until strict emissions limits occur in 2030) and a constraint limiting the annual emissions produced, as shown in (37).

All carbon reduction scenarios have transmission network constraints enabled between nodes and use historical data to represent interconnectors.

4.3.3. Representation of zonal pricing scenarios

For the zonal pricing scenarios, carbon reduction targets are represented by the current GB framework, with CfD payments to renewable generation and carbon pricing set as per the UK budget carbon price floor. The base case and zonal scenarios are represented in the SEDM as follows:

1) Base case

The base case scenario represents electricity trading in GB in its current form, without taking network constraints in to consideration. As such, the network is represented as unconstrained and the maximum flow constraint $f\max_{i,j,l}$ in (27) is set to an arbitrary number too high to be met (10^6 MW). Subsidy payments $EnPay_{g,p}$ are represented as the difference between the strike price for each generator minus the GB-wide SRMC, as in (24).

2) GB strike price

The GB strike price scenario represents electricity trading in GB with a zonal pricing mechanism and with GB-wide strike prices. The maximum flow constraint between Scotland and rGB $f\max_{i,j,l}$ is set at the National Grid B6 boundary constraint [130], and in demand blocks in which this constraint is hit a separate SRMC is calculated for the two zones. For this scenario subsidy payments $EnPay_{g,p,z}$ are calculated as the difference between the GB-wide strike price for each generator minus the zonal average SRMC in each model year, as in (39).

$$EnPay_{g,p,z} = StrikeP_g - SRMC_{p,z} \tag{39}$$

3) Zonal strike price

The zonal strike price scenario represents electricity trading in GB with a zonal pricing mechanism and zonal strike prices which represent the lifetime costs of wind generation based on the capacity factor of each zone. The most straightforward method of modelling this within the SEDM was to provide identical top-up payments to each technology type in the two zones. To represent the zonal strike price scenario the maximum flow constraint is set to the B6 boundary constraint as described above, but the energy payments $EnPay_{g,p,z}$ are calculated as the difference between the GB-wide strike price for each generator minus the rGB zonal average SRMC in each model year, as in (40).

$$EnPay_{g,p,z} = StrikeP_g - SRMC_{p,zrGB} \tag{40}$$

These zonal pricing scenarios are not set up in quite the same manner as those in the maximum profit without revenues scenario in the two node solver described in section 4.2.3. The zonal strike price scenario in the SEDM is most simply represented as equal top-up payments to generators in both the Scottish and rGB zones, whereas in the two zone solver zonal strike prices were represented as the lifetime costs of wind generation in the respective zones. The two zone solver method would have been too complex within the SEDM as the spatial detail of wind resource allowed for a much more complex representation of the different annual energy production over different regions, with AEP and thus LCOE differing for each model run and iteration. Also, the SEDM does not allow for the inclusion of revenue payments and so the only negative cost (payment) in the cost minimisation is the EnPay component representing the subsidy payments to renewable generation.

4.3.4. Model set-up and data sources

The SEDM has been updated and adapted for use in this work. Originally developed for the Scottish Government in 2012, this includes a complete model update undertaken for the Scottish Government in 2015 to change the model start year and prices from 2012 to 2014. All data sources for the model were reviewed and updated where necessary. The following section describes the data sources used for the updated version of the SEDM. Due to the increase in investment in solar PV in these years it was included as a new technology type, with existing, planned and candidate solar generation and appropriate seasonal availabilities for GB. Additional nodes were also input to represent areas interconnected to GB, i.e. France, the Netherlands and Ireland, with a generation mix appropriate for peak and off-peak generation included in each country. In light of the Conservative Government policies established after the first development of the model in 2012, the option was included for a user-enabled constraint to not provide any subsidy payments to new generation after 2020. Existing generation at this point would still gain their CfD top-up payments for the 15 year contract length.

For the investigation of the impact of two price zones in GB, CfD strike prices were updated from the auction results used by the Scottish Government to the levelised cost of energy (LCOE) for each type of generation receiving CfD payments, calculated using (14). This was to ensure that the model strike price represented the model input costs, and resulted in all generators being able to recover their lifetime costs through CfD payments, as they would in the real world.

4.3.4.1. Demand

The demand profile shape was taken from National grid demand data. The 2013 data set was used as the 2014 data set had gaps and both were similar [193]. Annual demand levels were taken from DECC energy and emissions projections central scenario 2014 [182]. Embedded solar and wind values were added to the annual figures for 2014 and scaled according to demand growth in subsequent years. The DECC projection values provide UK-wide energy consumption. This includes demand from Northern Ireland, but does not represent energy industry use or losses. The following quote comes from the DECC energy and emissions projections report [182] p31:

"Final energy demand gives figures for energy as its final consumers (households, businesses or public bodies) use it. It includes products in the form they are consumed like electricity, burning oil or transport fuels which are manufactured from primary forms of energy. These production processes involve some energy use and energy losses. They include: electricity generation, transmission and distribution; oil and gas production, distribution and refining; and the manufacture of solid fuel products such as coke."

As such, values for additional demand due to energy industry use and transmission losses and a subtraction of demand due to Northern Ireland's consumption were incorporated into the DECC electricity demand projection values in preprocessing. Losses are measured as a percentage of final consumption and figures for both losses and additional demand from energy industry use were taken from the Digest of UK Energy Statistics [51]. The percentage of total consumption from Northern Ireland was input to the model from a DECC report on sub-national electricity figures [185]. Nodal demand profiles are calculated using a nodal demand allocation factor based on historic demand profiles, all nodes in the SEDM have the same demand profile shape but with different load requirements. It should be noted that setting up demand inputs in this way assumes that demand profiles do not change with location within GB or in future years. The limitations associated with these assumptions are discussed further in section 6.3.3.

Generation dispatch is optimised in the long term model by use of aggregated load duration blocks instead of chronological time series. One short peak load block and three longer mid-range and baseload load blocks are used per season, as illustrated in Figure 16. This results in sixteen demand blocks representing each model year. This simplification reduces the number of decision variables and thus allows the model to solve in a reasonable time while still representing variations in demand.

Measures to ensure security of supply can be simulated in various ways using this model. A value of lost load (VoLL) can be input as a high price for energy not served that the cost minimisation will avoid paying. A system derated capacity margin is used to maintain generation adequacy, resulting in a percentage of additional generation that will be available at peak demand, shown previously as the system adequacy constraint (26). This value has been set to correspond to current EMR reports, as an additional 8% derated capacity by 2020 [194]. This represents generation adequacy measures in GB such as reserves and capacity markets. This annual de-rated capacity margin is dependent on technology-specific peak de-rating factors input to the model.

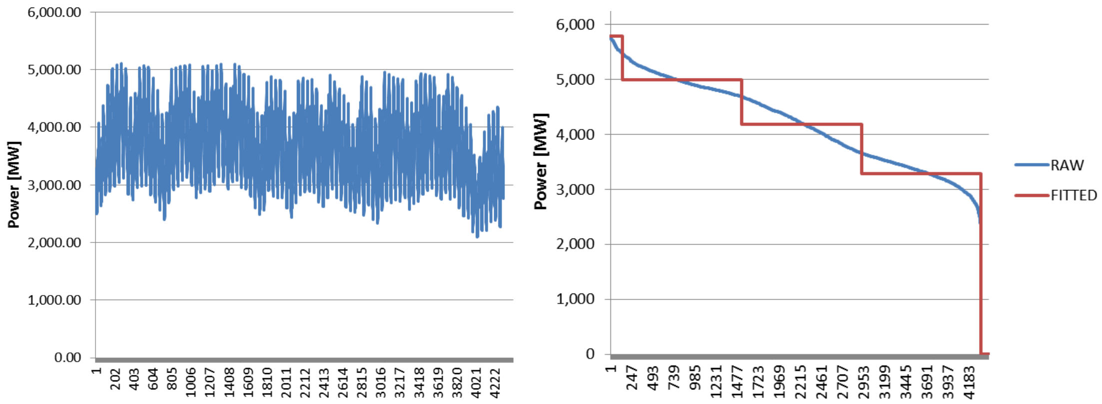


Figure 16 - Comparison of time series (left) with load curve and aggregated load duration blocks (right), from [180]. Note that the plots are intended to be illustrative, and refer to different seasons of data.

Including demand side management in the form of load shifting can be enabled by the user. In the long term model DSM is represented by an ability to move a small amount of demand from peak blocks to off-peak blocks. DSM is only included in the South England node (which contains the majority of GB demand) at a maximum of 5% of the peak block demand for this node. The overall sum of the change in demand is constrained to zero. Costs for DSM are from a Poyry report for DECC, which states that up to 760MW of DSM can be used at £100/MWh [195].

4.3.4.2. Generation

Generation in the model was updated using the National Grid Electricity Ten Year Statement (ETYS) 2014 [196]. Appendix F of the ETYS includes a list of generators and their status (existing, consents approved, awaiting consents and scoping) and their generating capacity each year from 2014-2035. Generators listed as 'existing', 'under construction' and 'consents approved' were input to the model in the appropriate node. Further generation is lumped into regional candidate generation for each technology at each model node, set as a continuous variable. Generators 'under construction' have been added as planned generation and those with 'consents approved' have been added in as candidate generation, with reduced costs due to some development already having taken place. Figure for this were taken from Parsons Brinckerhoff figures for prelicensing, technical and design and regulatory, licensing and public enquiry (£12.4/kW for CCGT and £30.1/kW for CCGT CCS) [197]. Embedded generation is included in Scotland, but not the rest of GB, with the exception of embedded wind and solar PV, which is included in all nodes. Must-run constraints are applied to nuclear generators.

Closure dates for plants with no closure date entry in the ETYS were researched on a generator-by-generator basis, and input to the model manually. Where no closure date is specified by the plant owner, it has been assumed that existing and planned biomass, CCGT, CHP and wind plants have a lifetime of 25 years and that coal and OCGT plants have a lifetime of 50 years. This comes from the original model assumption by Mercados, with a considerably longer lifetime for coal and OCGT plants due to the historic closure date data available. New CCGT was input with a lifetime of 30 years to match the amortisation time input to the model. Commissioning dates for all plants were taken from model preprocessing sheets and updated using DUKEs 2015 table 5.10 Power Stations in the United Kingdom [51].

Availability factors are used to represent maintenance and forced outages. Technology-specific seasonal availabilities were updated using the ETYS 2014 [196]. Technology-specific peak contributions were updated from Ofgem’s Capacity Assessment Report 2014 [198]. Generator thermal efficiencies in the model are used to calculate fuel costs. These come from a report for DECC by Parsons Brinkerhoff [197]. Embedded thermal generation is included in the Scottish nodes of the model. This data was taken from SHEPD and SPD and has been updated with current figures, also using DUKES figures for embedded thermal generation on Scottish islands [51]. Plant still operating under the Large Combustion Plant Directive at the start of 2014 were updated in the model with their remaining operational hours at this point using BM reports data from 2013-12-30 [199].

Thermal generation in the long term model is represented by linear operating costs based on a gross operational efficiency, whereas stochastic renewable generation is modelled a little differently. The wind resource is represented using a mixture of seasonal percentile averages of calibrated capacity factors using mesoscale model wind speed data from 21 onshore weather sites and 20 offshore weather sites, developed by the University of Edinburgh [200]. This is input to the long term model in three wind generation blocks for each demand block, in the ratio 1:2:1 for the ‘high’:’mid’:’low’ percentile averages. This is illustrated in Figure 17. The time series data are compared with historical demand data from 2001-2010, so that wind data corresponding to the maximum 10% demand time series are termed ‘peak’ and the remainder ‘off-peak’, to match the demand blocks in the model.

Existing wind and solar generation in the model is input as an aggregated installed capacity for each model area using the Renewable Energy Planning Database (REPD) [201]. Seasonal solar availabilities in the model were based on the embedded solar time series from National grid demand data [193] availabilities, assuming an overall average load factor of 10.2%, scaled at different nodes from geographical load factors as in DECCs Feed-in-tariff load factor analysis [202].

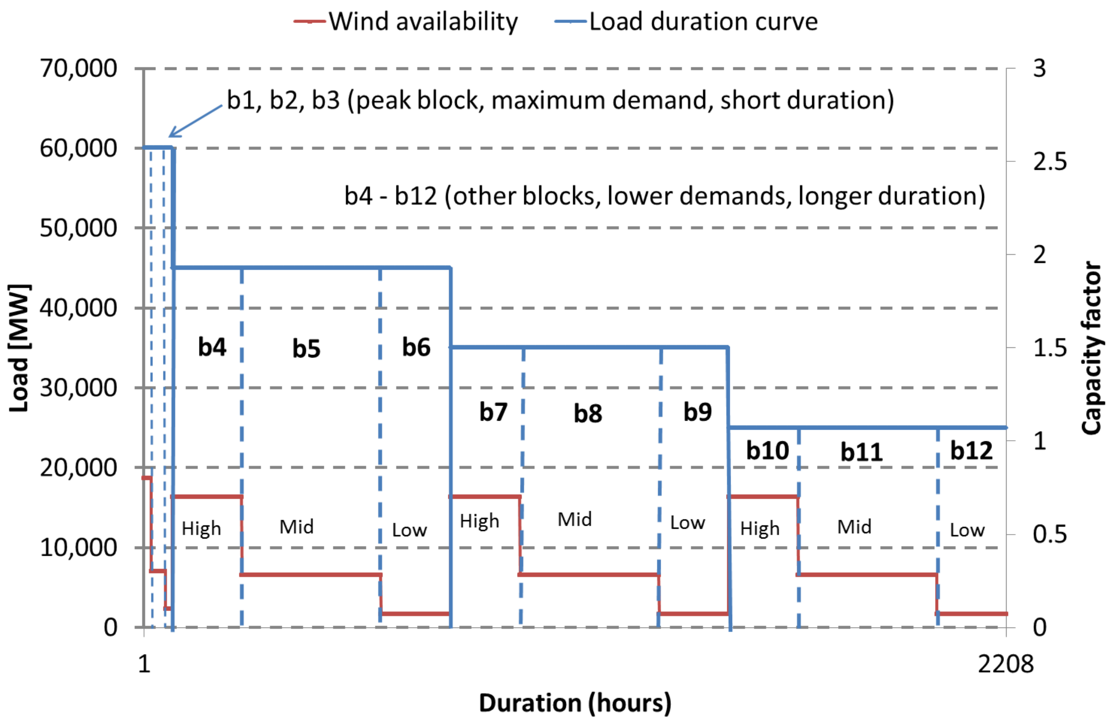


Figure 17 - Wind availability model inputs compared with load duration curve, from [180]

Hydropower with pumped storage is included in the model, but as the energy storage cannot be simulated chronologically in the long term model it is assumed that pumping will take place during baseload blocks and most of the generation will take place during peak blocks. This is illustrated in Figure 18. Run of the river hydro is considered must-run generation in the model and has availability factors based on seasonal load factors.

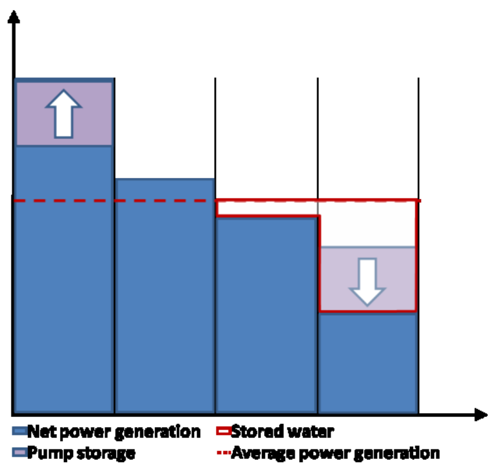


Figure 18 – Graphical representation of pumped hydro storage in SEDM, from [180]

CAPEX and OPEX values for planned and candidate generators came from DECC's Electricity Generation Costs report [177], and are converted from 2012 to 2014 prices using the appropriate GDP deflator [178]. To differentiate the risk associated with investing in various different technologies, technology-specific discount rates (hurdle rates) are modelled by a modification term to the capital costs of specific generators, with operational costs discounted at the social discount rate of 6.5% Technology-specific discount (or hurdle) rates were also updated using DECCs Electricity Generation Costs report 2013, input as an additional capital cost as described in (19). The hurdle rates used are shown in Table 10. It should be noted that these hurdle rates will change significantly with time and further development of these technologies. For example, after the initial SEDM modelling had been undertaken for this work the BEIS Electricity Generation Costs report 2016 had hurdle rates of well below 10% for offshore wind [33]. Operational costs are discounted at the social rate, meaning long run marginal cost (LRMC) values may differ from other models, which use technology-specific discount rates to calculate operational costs [177].

Table 10 – Technology specific hurdle rates used in the SEDM, from [177]

Technology	Hurdle Rate
Biomass Conversion	10.9%
Dedicated Biomass	12.7%
Hydropower	6.7%
Offshore Wind	9.6%
Offshore Wind R3	11.3%
Onshore Wind	7.9%
Tidal range	6.6%
Tidal stream (pre-commercial)	7.3%
Wave (pre-commercial)	7.4%

Fuel prices were updated using DECC's fossil fuel price projections. Biomass fuel projections were taken from the central value of a set of DECC estimates [203], scaled to the end of the model time horizon using an EA Energy Analyses report on Danish biomass prices [204], assuming the price projection of biomass would be similar for GB and Demark.

Constraints used to impact on investment decisions include the maximum total annual monetary investment, maximum installed total generation capacity and technology-specific maximum installed generation capacity. These constraints are described in more detail in section 4.3.1. Constraint limits are based on a number of commercially sensitive confidential reports and internal expertise at Mercados when creating the model, and so are not able to be made publically available.

Dispatch is represented by minimising the investment and operational costs of generation whilst meeting the energy balance constraint. As such, the cheapest generation will be dispatched first, and the total operating cost minimised. In this way the model represents perfect competition by dispatching based on the cheapest operational costs of available generation for each demand block, a simplified version of the merit order.

The wholesale price for each node is an output of the model and is represented by the system marginal price, i.e. the price to dispatch another MWh or the shadow price of the energy balance constraint at each node and block, energy-weighted to give an annual figure. When the model transfer capacity constraints are reached, i.e. the power transfer between nodes is equal to the maximum transfer capacity, each node experiencing transfer capacity constraints will have a different marginal price based on the locational generation mix.

4.3.4.3. Transmission

As described in section 4.3.1, the transmission network can be set as unconstrained, in which all inter-area transfer limits are set to a nominal high level (100,000MW). It can also be set as constrained, in which inter-area transfer limits are set using National Grid data [130]. In constrained mode, the model optimises transmission expansion alongside new generation, with planned and candidate upgrades to inter-area transfer capacities input as decision variables. For the purpose of this work, the model is unconstrained between all nodes except the Scotland-rGB boundary. The SEDM models the total transfer capability at this boundary, not as the sum of all of the thermal ratings of all the lines crossing one boundary, but the NG provided boundary transfer capability.

Transmission lines have been updated in the model from the NG Electricity Ten Year Statement (ETYS), updating line capacities based on the NG boundary transfer capabilities and inputting lines listed as under construction and in planning [196]. Those lines listed as ‘under construction’ in the ETYS were input to the model as planned and those listed as ‘in planning’ were input to the model as candidate. Line CAPEX was updated, using individual project costs were used from reports for Ofgem by Redpoint [205] and Parsons Brinckerhoff [206]. For those projects not listed in these reports, generic reinforcement prices were provided for various transmission boundaries in the Redpoint document. Transmission charging includes initial connection cost and locational costs due to Transmission Use of System (TNUoS) charging as part of fixed costs to generation in the unconstrained case. These values were represented in all years by National Grid data for locational TNUoS charges from 2015 applied to the relevant model node [207].

Interconnectors are assumed to be completely reliable (100% availability) and are not retired. As part of the model update interconnectors were set up as separate nodes with peak and off-peak generation to represent the generation mix of the interconnected country. Transmission capacity between GB and the interconnector nodes is limited to the interconnector net transfer capacity.

4.3.5. Representation of carbon reduction policies

Various low-carbon incentives are included in the model to capture current government policy. Carbon pricing is included as an additional operational cost for each thermal generator based on their emissions production, depending on their fuel source and generator efficiency. Government subsidies to low carbon generation are included in the form of Renewables Obligation Certificates and CfDs. These are included as a negative variable cost or 'payment' to generation built before and after 2015 respectively. Finally, the Large Combustion Plant directive has also been included, with all plants opting-out having been given reduced running hours until 2015, and retired at the end of 2015.

CfD strike prices were input at the levelised cost over the model lifetime for each technology type, calculated as in (14). The levelised cost values were used instead of the auction CfD values to ensure that lifetime costs were met in the model time horizon, as CfDs are intended to do. These calculated levelised costs are compared with the CfD auction results and other publically available sources of levelised costs in the following section. CfD contract lengths were set at 15 years, with nuclear generation contract lengths set at 35 years based on the contract length of the Hinkley C project. ROC values were set at the 2014/15 buyout level [208], and technology-specific ROC bands were set according to the DECC published values [209].

As mentioned in section 2.1.3.3, the future for CfDs and the LCF is uncertain. However, the UK Government has a legal obligation to meet renewables and carbon reduction targets out to 2050, and at the time this work was undertaken low carbon generation faced significant challenges in becoming competitive with carbon producing generation. As such, this work has been developed on the basis that medium and large scale projects will have access to CfDs beyond 2020.

4.3.6. Representation of zonal pricing scenarios

Zonal pricing scenarios have been represented in SEDM in a similar way to the method used for the two node solver in section 4.2.3. The base case scenario represents current trading in GB by use of an unconstrained model, with CfD top-up payments to all new low carbon generation set up as described in (24) in section 4.3.1.

To represent the zonal scenarios the transmission constraint between Scotland and the rest of GB is enabled, with the transfer capacity from the ETYS input as the maximum flow and the total flow between the two nodes limited as in (27). The energy payment term 'EnPay' in (23) is used as the CfD top-up payment amount and is altered depending on the scenario being represented.

For the GB strike price scenario, CfD top-up payments are calculated as the annual average zonal SRMC subtracted from the generation-specific GB-wide strike price, shown in (39):

$$EnPay_{g,p,z} = StrikeP_g - SRMC_{p,z} \tag{39}$$

where $StrikeP_g$ is the GB-wide strike price for each type of generation and $SRMC_{p,z}$ is the short-run marginal cost in each period and zone.

For the Zonal strike price scenario, CfD top-up payments are calculated as the annual average zonal SRMC in rGB subtracted from the generation-specific strike price, shown in (40). The zonal strike prices are calculated specifically so that the total top-up payments are equal in both zones for each type of generation. This equal top-up payment in both zones represents equal uplift to generation in both Scotland and rGB.

$$EnPay_{g,p,z} = StrikeP_g - SRMC_{p,zrGB} \tag{40}$$

Where $SRMC_{p,zrGB}$ is the short-run marginal cost in each period in the rGB zone.

There is an option to set a limit to the total spend from CfD top-up payments, representing the LCF. However, in the two zone solver it was necessary to include theLCF limit to install more than a single type of generation and represent the current GB energy mix. In the SEDM there are numerous other constraints already discussed which represent limitations on investment such as the supply chain and renewable resource, such that the LCF limit is not exceeded by 2020 even when no limit is explicitly set. A discussion can be found in 7.1.3 comparing the SEDM total spend on subsidies to renewable generation up until the period of 2020 with the current LCF budget.

4.3.7. Validation

Some validation was undertaken by Mercados on the production of the SEDM, comparing output installed capacity and generation results from the long term model to the National Grid Future Scenarios [210] and the Redpoint Market Reform analysis up to 2030 [211] and comparing output SRMC results from the short term model compared with GB output system prices from the Elexon portal [212]. In this validation work, results from the model were found to compare reasonably well with published sources, with the SEDM short term model tending to slightly underestimate the system price, which was assumed to be due to the modelling assumption of perfect competition. The differences in installed capacity and generation were assumed to be due to different assumptions with plant closures and derated capacity margins between the different models [180].

During the process of updating the model for the Scottish Government and for this work, some additional comparisons were performed to compare updated model inputs and outputs to published figures. Among those compared were the levelised costs used as strike prices and output installed capacity and generation.

Levelised costs were calculated for all low carbon technologies included in the SEDM. These were used to represent technology-specific strike prices within the model, as the CfD strike price is intended to represent the lifetime cost of the generator. In reality, each generating project has to estimate their lifetime costs when bidding in the CfD auction process to ensure that their project can make profit before it goes ahead. As future costs and revenue streams such as fuel prices, TNUOs charges and PPA contracts cannot be guaranteed, the CfD process still involves a certain amount of risk for investors. In the SEDM however, the investment cost optimisation inputs capital and operating costs for all years of the model time horizon, and the model makes investment decisions with perfect foresight. This means that strike prices can be chosen which represent the generator lifetime costs by calculating the levelised cost of each type of generation in the SEDM.

The calculation of levelised costs is the net present value of total costs for the generator divided by the net present value of electricity production over the generator lifetime, resulting in a cost per MWh of generation, as shown in (14). Table 11 shows the calculated levelised costs for each type of generation included in the SEDM. These were calculated using the input data described in the previous sections for capital costs, operational costs, fuel costs, emissions costs, technology-specific hurdle rates and generator availability. Wind generation capacity factors come from model outputs averaged over all generation for each class of wind generator (onshore, offshore round 1-2 and offshore round 3).

Table 11 also shows the current CfD auction results for each technology, and the levelised cost results from calculations undertaken by Mott MacDonald and DECC. Output levelised costs are very sensitive to their input parameters, as well as the discount rate used to calculate the net present values. As such, Mott MacDonald and DECC provide a range of levelised cost figures for each technology, based on low, central and high input cost parameters and different values for the discount rate. It can be seen that most of the calculated values fall in to the Mott MacDonald and DECC ranges, with the exception of Biomass, which does not fall within the Mott MacDonald range but agrees with the other figures. The Mott MacDonald report was produced in 2010 and so it could be that the assumed prices for biomass fuel did not agree with the more recent figures.

Table 11 – Levelised costs for various technologies, calculated and compared with CfD auction results [62] and administrative strike prices [213] from the first CfD allocation round in 2015 and reports from Mott MacDonald [32] and DECC [177]

Levelised Costs (£/MWh)	**Calculated figures:**		**Sources:**			
Technology	**2016 start date**	**2020 start date**	**CfD auction results (2015)**	**Administrative strike prices (2015)**	**Mott MacDonald range (2010)**	**DECC range (2013)**
Onshore wind	**84.75**	**81.08**	79.99 - 82.5	-	71.3 - 93.9	69 - 115
Offshore R1-2	**119.74**	**116.10**	114.39	155	93.7 - 160.9	90 - 168
Offshore R3	**121.14**	**116.24**	119.89	155	107.6 - 190.5	104 - 208
Biomass	**126.49**	**125.69**	-	125	66.4 - 93.2	106 - 157
Biomass conversion	**77.23**	**76.78**	-	105	-	105 - 117
Solar	**111.61**	**101.17**	50 - 79.23	120	-	101 - 116
Hydro	**119.84**	**122.59**	-	100	-	-
Tidal Range	**-**	**149.94**	-	-	-	-
Tidal Stream (shallow)	**-**	**196.63**	-	305	-	-
Tidal Stream (deep)	**-**	**131.08**	-	305	-	-
Wave	**-**	**223.88**	-	305	-	-
nuclear	**-**	**89.77**	-	-	53.4 to 99	79 - 102
CCS Coal (ACS)	**-**	**136.51**	-	-	93.3 to 142.1	97 - 159
CCS Coal (IGCC)	**-**	**145.79**	-	-	90 to 147.6	116 - 209
CCS Gas	**-**	**130.66**	-	-	67.7 to 123.8	94 - 118

When first compared with the Mott MacDonald and DECC levelised cost ranges, the original CCS values calculated from the model input data were very low (less than offshore wind) and so the input data was changed to reflect the upper input cost ranges for CAPEX and OPEX and include CO_2 transport and storage costs from the Mott MacDonald report.

It is important to note when looking at these figures that all of this work was undertaken using DECC's Electricity Generation Costs report from 2013, as the updated Generation costs report was not published until late 2016. Some levelised costs, particularly solar PV and wind generation have fallen a great deal since this work was completed [33]. The 2017 and 2019 CfD auction results have reflected this reduction in costs [63].

Another form of validation undertaken was a comparison of the SEDM output installed capacity and generation in certain years to those predicted by National Grid in their Future Energy Scenarios (FES). Overall these compared well, with installed capacity and dispatch results for most technology types falling within the range of the FES. Figure 19 shows the installed capacity and dispatch results for wind generation from the base case scenario compared with the FES scenarios. It can be seen that the overall wind installed capacity is similar to that of the FES Slow Progression scenario until 2020 and then similar to that of the No Progression scenario from 2025-2030. The wind generation dispatch results are also similar to Gone Green until 2020 and then fall between No Progression and Low Carbon Life until 2030. The difference between these two sets of results could be due to the assumptions made of installed capacity location and capacity factors, as the unconstrained SEDM prioritises installing wind generation in areas of high capacity factors in the north of Scotland and Shetland. It was not expected that the results would fall exactly into one of the FES scenario categories, as the input assumptions for demand are not the same for National Grid as DECC figures are used in the SEDM.

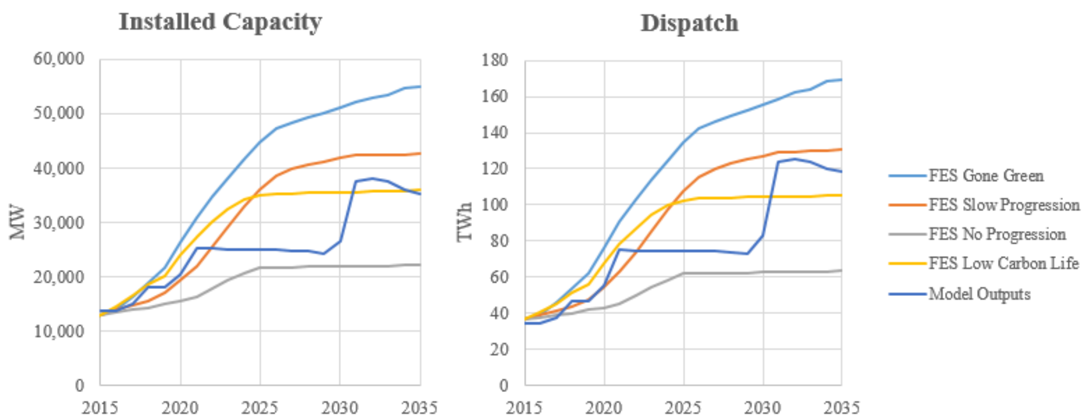


Figure 19 – SEDM base case results output installed wind generation capacity and dispatch from 2015-2035 compared with National Grid's 2014 FES results

Chapter 5.

Modelling zonal pricing in GB – a two node solver

In this chapter the two node solver results are explored. Two types of modelling are undertaken, with the objective function representing 1) the minimum cost to society and 2) the maximum profit to generators. Due to the simplifications and assumptions involved, scenario comparison is the most valid way to derive insights from the investment modelling undertaken for this work. The differences produced by running the two zonal scenarios are investigated, with the installed capacity, dispatch and carbon emissions production results compared with a base case in which GB trades as a single zone. Two sensitivity analyses are also included, investigating the sensitivity of the maximum profit results to the inclusion of 20% headroom in the Levy Control Framework (LCF) and the inclusion of the additional transfer capacity between Scotland and rGB from the Western HVDC Link. All of the scenarios modelled and discussed in this chapter are shown in Table 12, with the type of objective function, inclusion of revenue payments, LCF constraint and inter-zonal transmission capacity constraint.

It should be noted that while the inclusion of negative cost terms to represent 'revenue payments' are included in the profit maximisation objective function to properly represent the potential impact of zonal pricing on investment in generation, it would not be accurate to include positive cost terms to represent such payments in the cost minimisation objective function, as these costs to the consumer are already represented in the CAPEX and OPEX figures.

Table 12 – Scenarios investigated using the two node solver

Scenario	Objective function	Includes revenues	LCF	Transmission capacity
Minimum cost to society – base case	Cost minimisation	No	£32.8bn	unconstrained
Minimum cost to society – GB wide strike price	Cost minimisation	No	£32.8bn	3.3 GW
Minimum cost to society – zonal strike price	Cost minimisation	No	£32.8bn	3.3 GW
Maximum profit to generators – base case	Profit maximisation	Yes	£32.8bn	unconstrained
Maximum profit to generators – GB wide strike price	Profit maximisation	Yes	£32.8bn	3.3 GW
Maximum profit to generators – zonal strike price	Profit maximisation	Yes	£32.8bn	3.3 GW
Sensitivity analyses				
Max profit with LCF +20% - base case	Profit maximisation	Yes	£39.4bn	unconstrained
Max profit with LCF +20% - GB wide strike price	Profit maximisation	Yes	£39.4bn	3.3 GW
Max profit with LCF +20% - zonal strike price	Profit maximisation	Yes	£39.4bn	3.3 GW
Max profit with Western HVDC Link – base case	Profit maximisation	Yes	£32.8bn	unconstrained
Max profit with Western HVDC Link – GB wide strike price	Profit maximisation	Yes	£32.8bn	3.3 - 6.5 GW
Max profit with Western HVDC Link – zonal strike price	Profit maximisation	Yes	£32.8bn	3.3 - 6.5 GW

5.1. Minimum cost to society

This section displays results from the scenarios undertaken assuming that the key priority in system planning is minimising the possible cost to society. The two node solver model set-up represents current policy in GB, including carbon pricing and the LCF. As described in detail in Chapter 4, all of these costs are minimised in this set of scenarios, including additional subsidy payments to low carbon generation in the form of CfD top-up payments.

The scenarios explored in this section are a base case scenario in which there is no zonal pricing and the two zonal pricing scenarios representing a GB-wide strike price and Zonal strike prices, previously discussed in Chapters 3 and 4. The subsidy terms for these scenarios are discussed in more detail in section 4.2.3.

The resultant six-year average revenue streams of low carbon generation in the two zonal scenarios are compared with the base case scenario in Figure 20. These represent the years 2015-2020 in the model set up.

There are two sets of results shown for the GB strike price scenario, labelled (a) and (b). This is because the iteration process for determining the SRMC and thus the top-up payments for renewable generation did not converge, resulting in two sets of results that repeat rather than converging to a single solution. The iteration process begins with input SRMCs and top-up payments assuming that CCGT will be the marginal generator in both zones in all model years. The iteration process is run using the SRMC outputs from a previous run as the inputs for the following run. In this case, the two results sets (a) and (b) both have market splitting. In the case of results set (a), due to the larger capacity factor in Scotland and thus the comparatively lower levelised cost, wind capacity is built in Scotland in model years 1-3 until the transmission constraint is met in the off peak demand block. After year 3 the LCF constraint has been hit and no more wind can be installed. In years 1-5 transmission flows are in the direction of Scotland to rGB, hitting the maximum transfer capacity in the off-peak demand block. As a result, market splitting occurs in years 1-5 in this larger demand block and the resultant Scottish zonal SRMC is low in all years, as wind is the marginal generator in Scotland. Low output SRMCs result in higher top-up payments to Scottish generators in the next iteration (b), and Scottish wind is seen as comparatively more expensive than wind in rGB. As such, in iteration (b) the LCF constraint is used up by wind generation only installed in Scotland. In this case, net flows occur in the direction of rGB to Scotland in every year, hitting the transmission constraint in years 3-5 in the off-peak block. In the next iteration, the results are the same as in (a) as the higher marginal price in years 1 and 2 in the Scottish zone means that top-up payments are lower and wind is again invested in to a greater extent before meeting the LCF constraint. The solutions continue to repeat (a), (b), (a), (b) and do not converge. This failure to converge to a single solution is discussed in more detail in section 5.4.2.

In Figure 20 it can be seen that the GB strike price (a) and Zonal strike price scenarios produce a lower average zonal price (represented by zonal SRMC) in Scotland. This is due to market splitting occurring in every model year except for the final year, in addition to a high investment in wind in Scotland (where capacity factors are higher and thus lifetime costs per unit of generation are lower) driving down the Scottish SRMC when market splitting takes place, i.e. when exports from Scotland reach the network transfer limit. In the base case scenario the transfer capacity is set higher than demand in either node to represent an unconstrained system and so no zonal splitting takes place and the SRMC remains the same in both zones. In the GB Strike Price (b) scenario the average SRMC is higher in the Scottish zone than in (a), but still lower than the rGB zonal average SRMC. Market splitting occurs in model years 3-5 in this scenario as the maximum export capacity is reached from Scotland to rGB, with lower zonal SRMCs in the Scottish zone. Six-year average top-up payments are the highest in the Scottish zone in the GB strike price (a) and Zonal strike price results at £94.53/MWh, as the six-year average zonal SRMC drops to £9.87/MWh. The average price for these blocks is greater than zero as wind generation only sets the marginal price in the off-peak block, with

CCGT setting the marginal price in the peak block. In the GB strike price (b) scenario results, six-year average top-up payments in the Scottish zone are £80.43 from an average SRMC of £23.97. In the base case and the rGB zone for the zonal scenarios the six-year average top-up payments are £58.41/MWh from an average SRMC of £45.99/MWh as CCGT is marginal in both demand blocks.

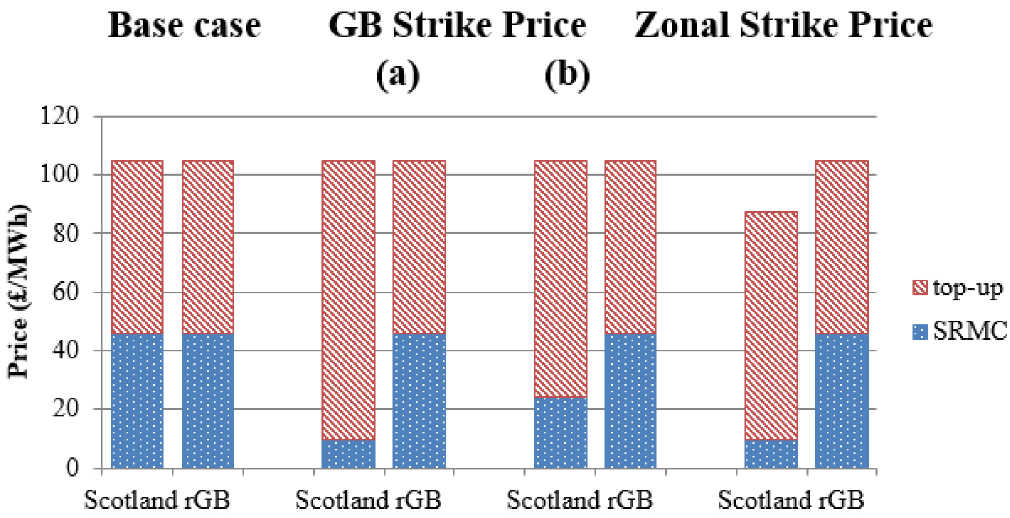


Figure 20 – Resultant output model average SRMC and top-up payments for each zone in each of the scenarios, from an objective function minimising total cost to society.

The total installed renewable capacity for each model year in the base case and zonal scenarios is shown in Figure 21 and the final year installed wind capacity for each zone is shown in Figure 22. It should be highlighted that this model has a greenfield set-up, with no prior installed capacity assumed, to best illustrate the impact of the model set up to each of the scenarios results. The base case and zonal strike price scenario results show an annual increase in wind installed capacity until year 4, as the model demand increases each year and new capacity is installed in each year to meet this constraint. After year 4, the LCF constraint has been reached, and so no further wind is installed in model years 5 and 6. The GB strike price scenario results follow a similar pattern with an annual increase in wind installed capacity up until year 3. In the base case all of the installed wind capacity is located in Scotland as the higher capacity factor results in an overall lower levelised cost and there is no transmission constraint limiting the total Scottish generation. The resultant net flows between Scotland and rGB are greater than the B6 boundary limit set in the zonal scenarios in all model years, with the direction of flow from Scotland to rGB. In the zonal scenarios the wind capacity cannot be entirely installed in Scotland to meet the LCF constraint as this would surpass the transmission constraint, and so some wind capacity is also installed in rGB. This is shown in Figure 22.

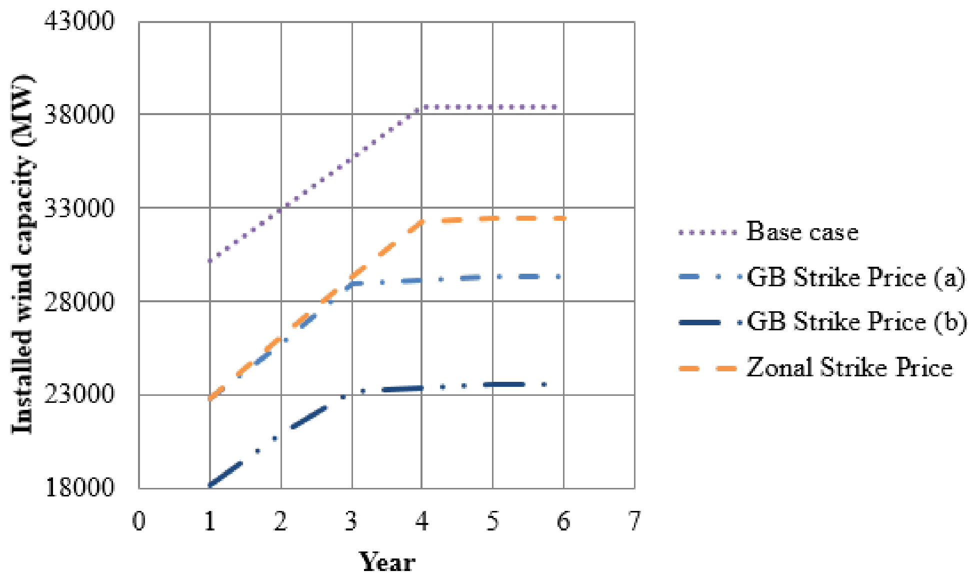


Figure 21 - Installed wind capacity in each year for all scenarios, from an objective function minimising total cost to the consumer

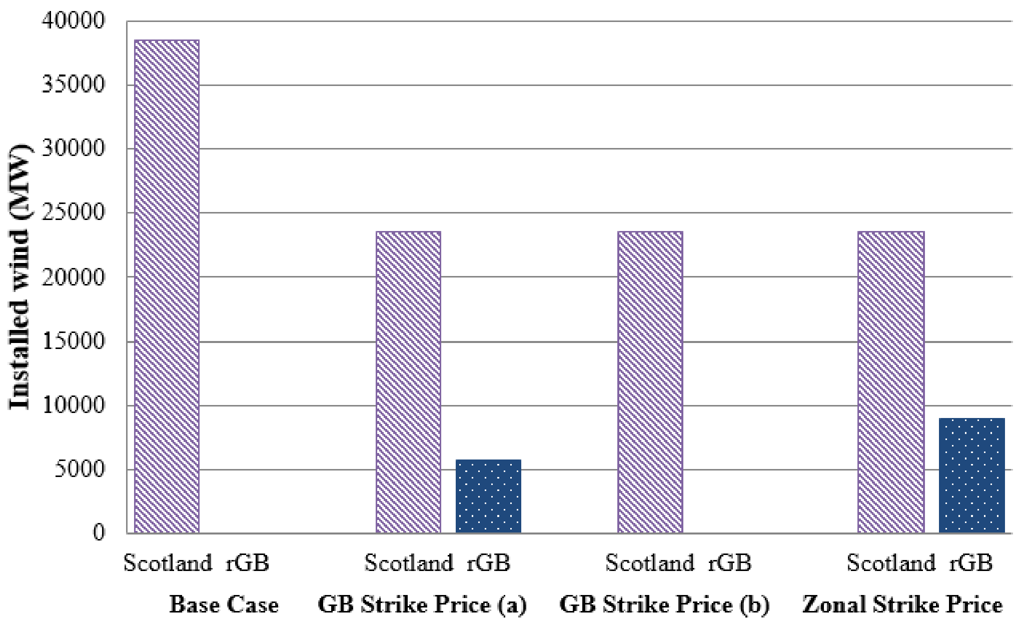


Figure 22 - Total installed capacity over the six-year modelling horizon in Scotland and rGB in all scenarios, from an objective function minimising total cost to the consumer

The Zonal strike price installed capacity results are different to those for the GB strike price (a) scenario, as the top-up payments per MWh are different in both zones in every year due to the differing zonal prices. This means that wind in Scotland seems comparatively cheaper than that in rGB due to the lower zonal price and the higher capacity factor. Wind is installed in Scotland in year 1 until the transmission constraint is hit in the off-peak block and no more generation can be exported to rGB. Additional wind is installed in Scotland each year until year 5 to meet the rising Scottish demand. The remainder of the LCF constraint is met by wind installed in rGB in model years 2-4. At model year 5 the total amount of wind generation meets the LCF constraint and so no more wind can be installed in year 6. As the transmission constraint is hit in the off-peak block in model years 1-5, market splitting occurs in this block and the resultant Scottish SRMC is low in these years. In the zonal scenario, the output SRMCs are used as an input for the following iteration of the model and in this case the model converges with these results as the only solution.

The difference between the installed renewable capacity in the scenarios is due in part to the zone in which the wind generation is installed, which is dependent on the total cost of top-up payments in each of the zones, the maximum capacity factors in each zone and thus the total cost of installing and dispatching wind generation. It can be seen from Figure 21 that the GB strike price scenario results has the lowest installed wind capacity. This is because of the high top-up payments in the Scottish zone, and the LCF constraint limiting the total subsidy spend. Figure 22 shows the total installed capacity in each zone in the final model year in each of the zonal scenarios and the base case scenario. It can be seen that the zonal scenarios install as much wind generation as possible in Scotland before hitting the maximum generation constraint due to the transmission capacity between Scotland and the rest of GB. The amount of wind installed capacity in rGB in the zonal scenarios depends on the available LCF budget. The zonal strike price scenario has the highest installed wind capacity in rGB as the Scottish zonal price is lower here, meaning more of the LCF budget is available. The base case scenario has the highest installed wind capacity, as top-up payments for the Scottish zone are considerably less and there are no transmission constraints to limit dispatch in this zone.

It can be seen that the final installed wind capacity also differs greatly between scenarios. This is in part due to the differing capacity factors in both zones resulting in a higher installed capacity required in rGB to produce the same generation as a lower installed capacity in Scotland. In the base case scenario, with no transmission constraints included, the installed capacity of wind is greater than in the zonal scenarios as it is entirely located in Scotland. This does mean that power flows are in excess of the B6 boundary constraint, however. The installed capacity of wind in the zonal scenarios is consistently lower than the installed capacity of wind in the base case scenario, as the top-up payments are greater in the Scottish zone where the majority of wind capacity is installed.

Figure 23 shows the comparative total cost to the consumer and cost to the producer for each of the zonal scenarios and the base case scenario over the six-year modelling horizon. The cost to the consumer is represented by the costs that will be reflected in the consumer's energy bills: the total market revenues plus the total LCF spend. The cost to the producer is represented by the costs that the energy producer will incur, including capital costs, O&M costs, fuel costs and carbon costs. It can be seen that the lower installed capacity of wind in the zonal scenarios leads to a lower total cost to the producer for each of these scenarios compared with the base case. The carbon emissions produced in the zonal scenarios are much higher than the base case, reflecting the higher amounts of CCGT generation in these scenarios. It would appear that the base case scenario is the least cost-effective for the producer and the consumer however, due to the higher installed capacity and dispatch of wind. The GB Strike price (a) and Zonal strike price scenarios are most cost effective for the consumer, while the GB strike price scenario (b) is the most cost effective for the producer. As the LCF spend is the same, the difference in cost to the consumer must be due to the difference in wholesale market price of electricity, represented here by the zonal SRMC. However, without a representation of the actual transmission constraint between Scotland and rGB in the base case no final conclusions can be drawn. In reality, it would be impossible to utilise all of the wind generation capacity available in Scotland in this scenario, which would mean that the LCF target is not met. More wind generation capacity must be built in rGB or there must be investment in upgrading the transmission system. This is discussed further in section 5.4.1.

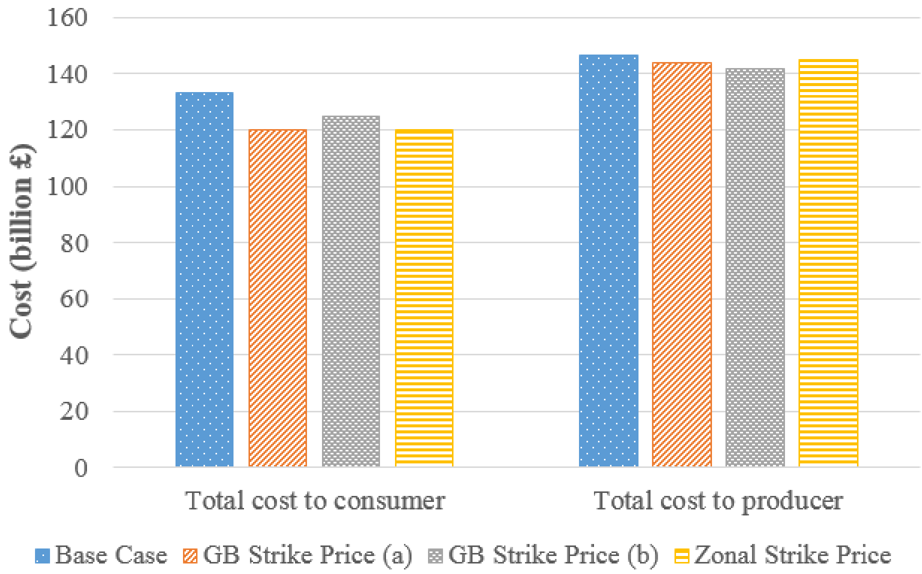


Figure 23 – Comparative total cost to consumer and total cost to producer in all scenarios, from an objective function minimising total cost to the consumer

The total cost to the producer is greater than the total cost to the consumer for each of the scenarios. This is due to the inability of CCGT generation to recover their long term costs with revenues represented by short run marginal costs (SRMCs). This is discussed further in section 5.4.4.

Figure 24 shows the comparative carbon emissions produced over the six year modelling horizon for each of the scenarios. It can be seen that the base case scenario results have the lowest carbon emissions. These results are not surprising given the wind installed capacity results in and , in which the base case has the highest wind installed capacity and thus requires the least amount of carbon producing CCGT to meet the remainder of model demand. It can also be seen that the GB strike price (b) scenario results have the highest carbon emissions, as this model run resulted in the least installed wind capacity and thus requires the most CCGT to meet the remainder of demand. It should be noted that the carbon emission figures shown in Figure 24 should not be taken to be representative of GB system output, as this simplified model is only representing two forms of generation, wind and CCGT.

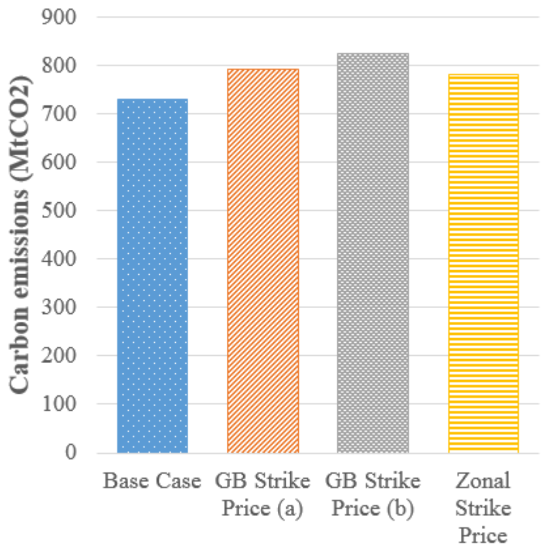


Figure 24 – Total carbon emissions over the six year modelling horizon for all scenarios, from an objective function minimising cost to the consumer

5.2. Maximum profit to generators

This section displays results from scenarios undertaken assuming that the key priority in investment planning is the maximisation of profit to developers. As in the previous section, the scenarios explored are a base case scenario in which there is no zonal pricing and the two zonal pricing scenarios representing a GB-wide strike price and a Zonal strike price, as previously discussed in Chapters 3 and 4. The subsidy terms for these scenarios are discussed in more detail in section 4.2.3.

Figure 25 shows the resultant six-year average SRMCs and top-up payments for each of the scenarios modelled, representing the years 2015-2020 in the model set up. Again it can be seen that the GB strike price zonal scenario results do not converge to a single solution in the SRMC iteration process. The results show that market splitting occurs in every model year in the GB strike price (b) and Zonal strike price scenarios and that the SRMC results are lower in Scotland in every model year due to wind generation setting the marginal price in the off-peak block.

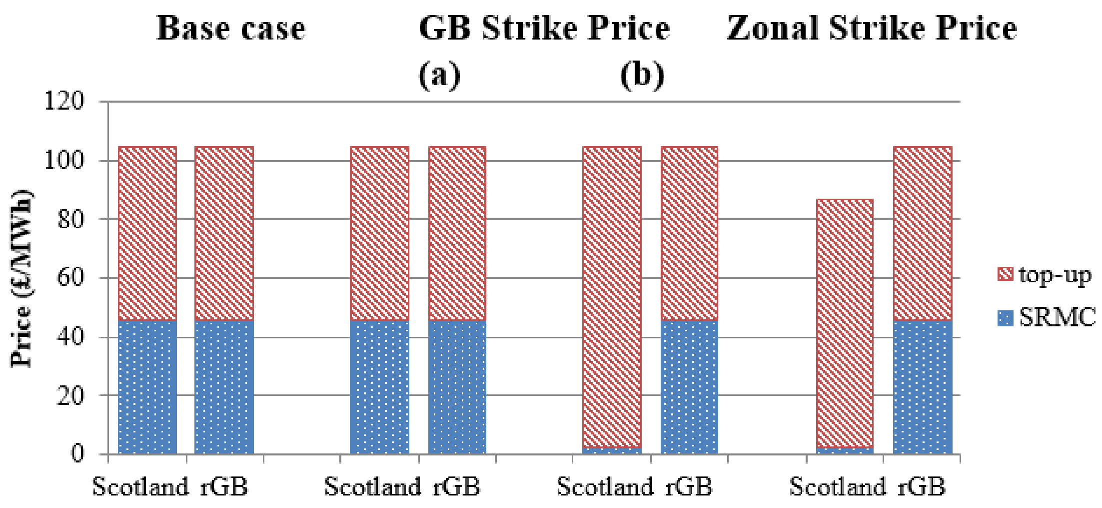


Figure 25 - Resultant model average SRMC and top-up payments for each zone in each of the scenarios, from an objective function maximising profits to generators and with revenue payments

Figure 26 shows the installed wind capacity in each year for each of the results sets and Figure 27 shows the total installed wind capacity in each zone over the six-year modelling horizon. The base case scenario results again install all of the wind capacity in Scotland. However, this time it is all installed in the first model year until the LCF constraint is met. Net power flow is from Scotland to rGB, at a level greater than the transmission constraint imposed on the zonal scenarios in every model year.

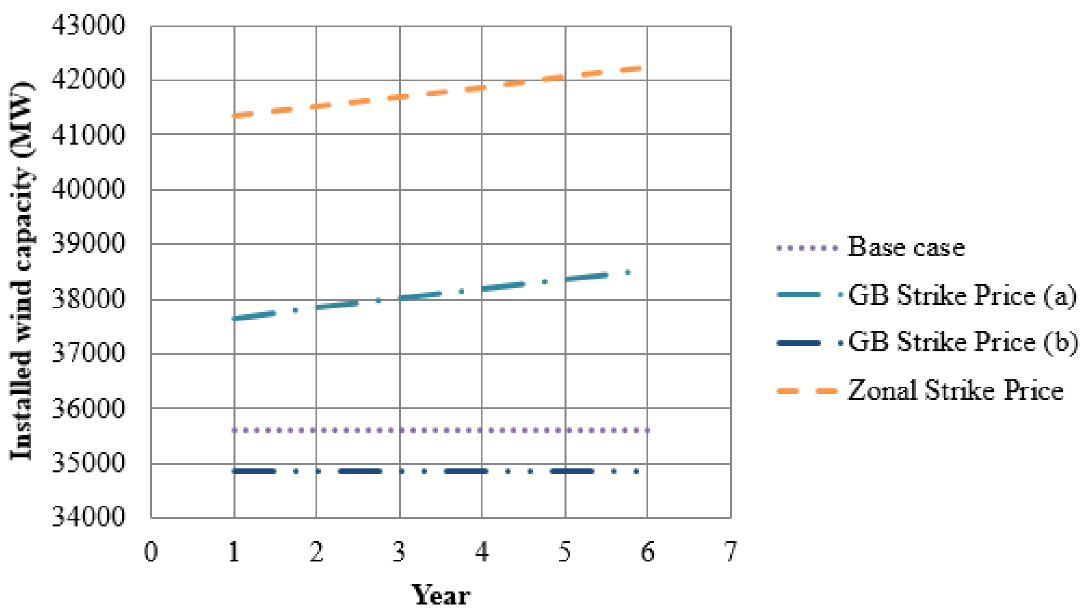


Figure 26 - Installed wind capacity in each year for all scenarios, from an objective function maximising profits to generators and with revenue payments

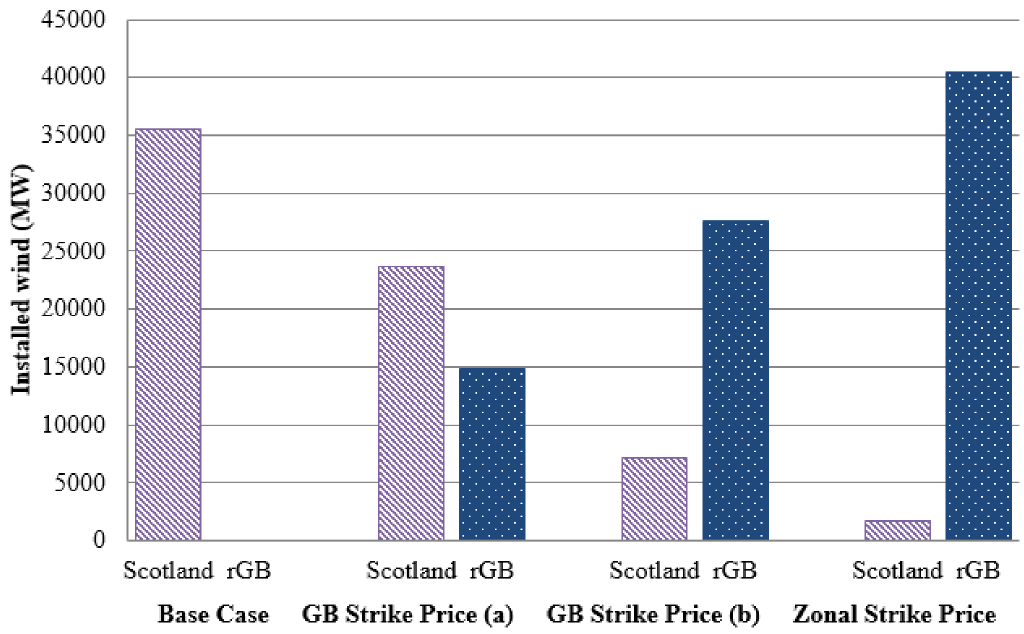


Figure 27 - Total installed capacity over the seven-year modelling horizon in Scotland and rGB in all scenarios, from an objective function maximising profits to generators and with revenue payments

In the GB strike price (a) scenario we again see that the SRMC iteration process has not converged. However, the results displayed here differ greatly from the cost minimisation results displayed previously. In the first iteration (a), the SRMC in each year is set to that assuming CCGT is marginal in every model year. Wind is installed in the Scottish zone until the transmission constraint is reached in the off-peak demand block in every model year, and then in the rGB zone until the LCF constraint hits. Net transmission flows are in the direction of Scotland to rGB in all years. Wind is comparatively more profitable in Scotland, having a higher capacity factor and producing more generation per MW of installed capacity than wind in rGB. As market splitting happens in all years, the SRMCs for the Scottish zone are low in all years, and these feed in as the input SRMCs in the following iteration. In the GB strike price (b) results, wind generation is installed in much greater proportions in the rGB zone, as the lower SRMC in the Scottish zone means that the top-up payment is much higher and would use up the LCF constraint with much lower installed capacity. The output SRMCs of this run are equal to the short run costs of CCGT in both zones, as market splitting does not take place. The solutions continue to repeat (a), (b), (a), (b) and do not converge. This failure to converge to a single solution is discussed in more detail in section 5.4.2.

The Zonal strike price scenario results also differ in this set of profit maximisation scenarios from the previous cost minimisation results. In this case, with the difference in the zonal strike prices resulting in a different uplift in £/MWh on top-up payments in both zones and a higher marginal price in rGB included as revenue payments, the wind generation in rGB generates more revenues per MWh than wind generation in Scotland. Wind is thus mostly installed in rGB, and the transfer limit is hit between rGB and Scotland in all blocks and years, with rGB exporting to Scotland in all cases. Some wind generation is installed in Scotland so that the Scottish off-peak demand block is met only by imports from rGB and Scottish wind. The model only builds CCGT in Scotland to meet the additional peak block generation as due to the comparatively cheaper capital costs and more expensive variable costs (e.g. fuel), CCGT has a much lesser levelised cost when only running 5% of the time in the peak block compared with wind generation.

Figure 28 shows the comparative total cost to the consumer and cost to the producer for each set of results. The GB strike price (b) results have the lowest cost to the consumer and the GB strike price scenario (a) and the base case results have the highest cost to the consumer. Cost to the consumer is directly related to wind installed capacity, so this result is unsurprising. Conversely, the base case results have the lowest total cost to the producer and the zonal scenarios have higher costs to the producer. This is due to the comparatively higher installed wind capacity in the zonal scenarios. As found in the cost minimisation results section, the total cost to the producer is greater than the total cost to the consumer for each of the scenarios. This is due to the inability of CCGT generation to recover their long term costs with revenues represented by short run marginal costs (SRMCs), discussed further in section 5.4.4.

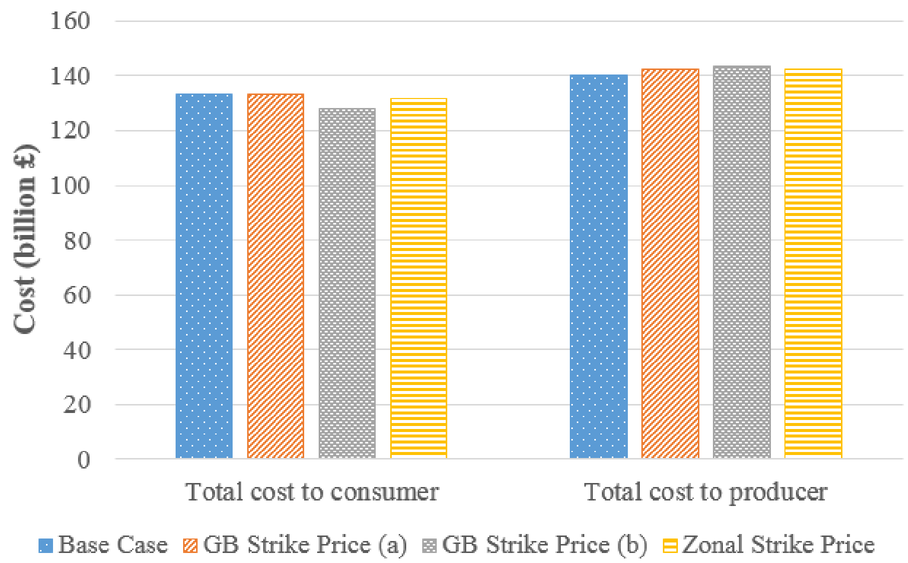


Figure 28 - Comparative total cost to consumer and total cost to producer in all scenarios, from an objective function maximising profit to generators and with revenue payments

Figure 29 shows the comparative carbon emissions produced over the six year modelling horizon for each of the scenarios. The carbon emissions output are highest for the GB strike price (b) scenario and lowest for the GB strike price (a) scenario and the base case, reflecting the higher wind generation and lower CCGT generation in these scenarios.

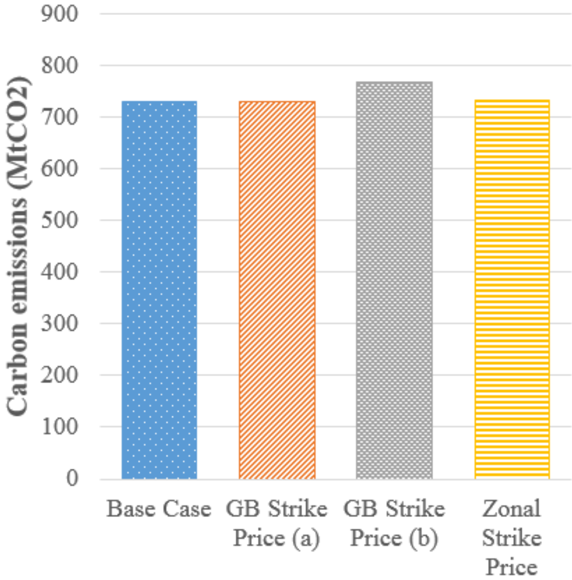


Figure 29 - Total carbon emissions over the six year modelling horizon for all scenarios, from an objective function maximising profit to generators and with revenue payments

5.3. Sensitivity Analyses

This section presents two sensitivity analyses, investigating the impact on results from the zonal scenarios with an objective function maximising the profit to generators by an additional 20% headroom in the LCF budget and by the addition of transmission capacity between Scotland and rGB, in the form of the Western HVDC Link. For the LCF budget sensitivity analysis the $LCF_{\lim}$ term in the objective function is increased by 20% in all scenarios and for the Western HVDC Link sensitivity analysis the $PTC_{y,b}$ term in the objective function is increased by 2.2GW in the zonal scenarios.

5.3.1. Sensitivity Analysis Results – LCF budget

Figure 30 shows the resultant model six-year average SRMCs and top-up payments from the set of model runs maximising profits to generators with the LCF budget increased by 20%. It can be seen that for this sensitivity analysis, both of the zonal scenarios have failed to converge the SRMC iteration process. Figure 31 shows the annual installed wind capacity for all scenarios with the additional 20% in the LCF budget constraint and Figure 32 shows the total installed wind capacity in each zone for each of these scenarios. Both begin with iteration (a) in which SRMCs are set to the short run costs of CCGT. Both then install as much wind as possible in the Scottish zone until the transmission constraint is met, with the remainder of wind generation installed in rGB until the LCF constraint is met. More wind can be installed in rGB in the Zonal strike price scenario as the lower strike price in the Scottish zone means that the LCF is less impacted by the Scottish generation. In both zonal scenarios the Scottish wind generation hitting the transmission constraint results in market splitting in every model year, and thus low zonal SRMCs in the Scottish zone output from (a) and input to (b). This lower SRMC results in the high top-up payments in the Scottish zone, meaning wind capacity installed in rGB is a more cost effective way of meeting the demand and LCF constraints. The zonal strike price scenario sees more installed wind capacity in rGB than the GB strike price scenario for iteration (b) as the higher strike price in the rGB zone means that wind generation dispatched in rGB will produce higher revenues per MWh and thus a higher profit in the profit maximisation objective function.

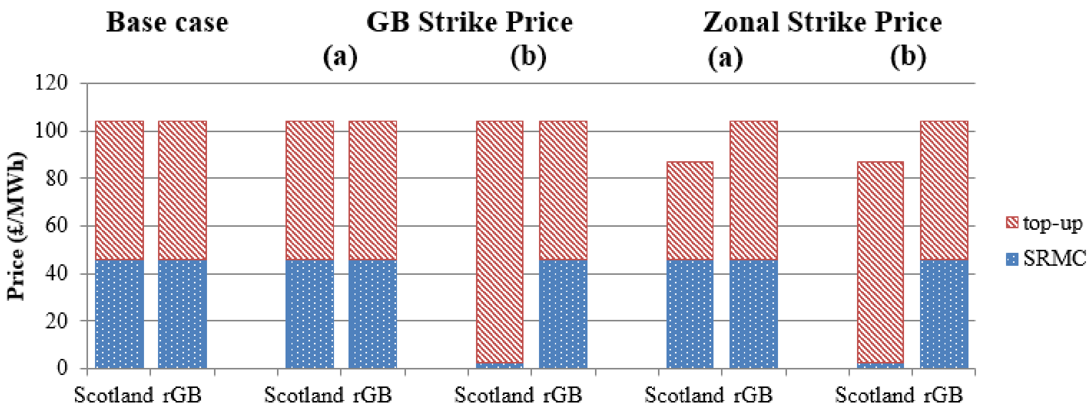


Figure 30 - Resultant model average SRMC and top-up payments for each zone in all scenarios, from an objective function maximising profits to generators, with revenue payments and 20% larger LCF budget

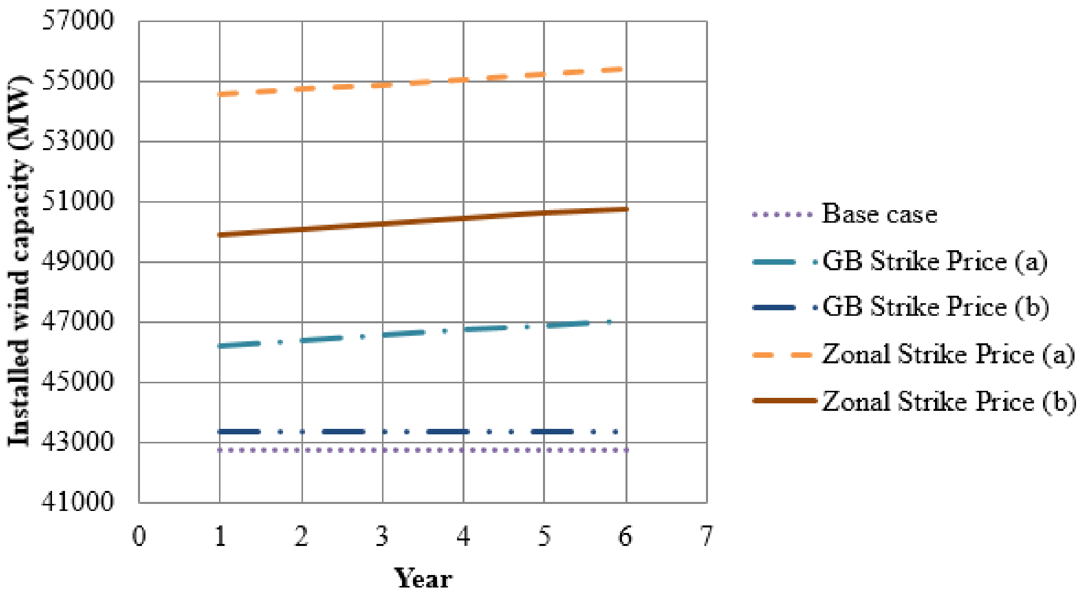


Figure 31 - Installed wind capacity in each year for all scenarios, from an objective function maximising profits to generators, with revenue payments and 20% larger LCF budget

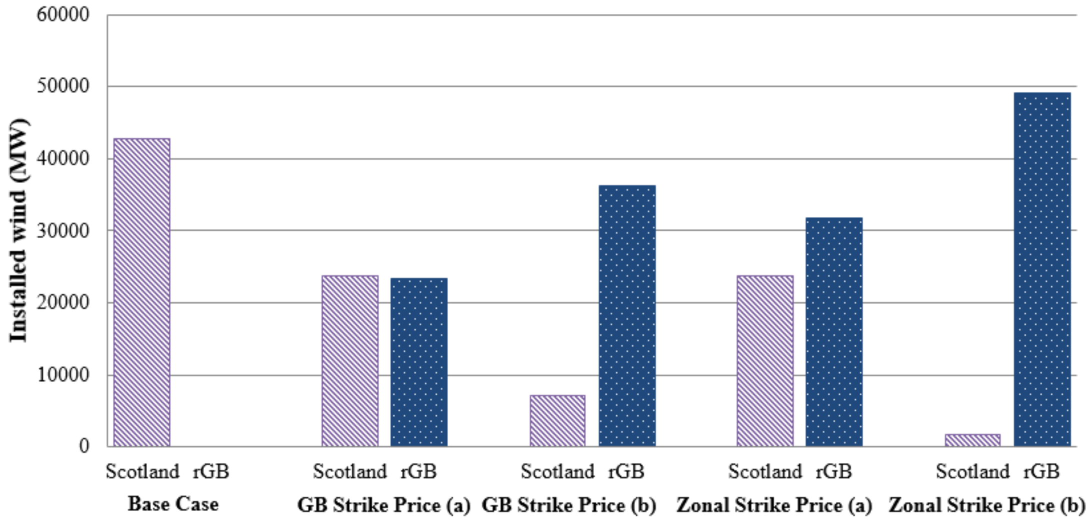


Figure 32 - Total installed capacity over the seven-year modelling horizon in Scotland and rGB in all scenarios, from an objective function maximising profits to generators, with revenue payments and 20% larger LCF budget

By comparing Figure 32 with Figure 27**Error! Reference source not found.** it can be seen that in the results set with additional headroom, the additional wind generation in Figure 32 is installed in Scotland in the base case scenario (without transmission constraints) and in rGB in the zonal scenarios. This is due to the fact that the maximum installed capacity installed in Scotland to meet demand plus export in the off-peak block in the GB strike price scenario and to meet demand minus export in the off-peak block in the zonal strike price scenario has already been achieved between Scotland and rGB in both of the zonal scenarios in the previous results set and so additional wind capacity is built in rGB in this sensitivity analysis to meet additional demand in this zone.

Figure 33 directly compares the installed wind capacity with the previous results set without the additional headroom, discussed in section 5.2. It can be seen that increasing the LCF allows a greater installed capacity of wind generation in all scenarios, as under the profit maximisation wind generation produces a higher profit than CCGT and will be installed over CCGT. This also leads to a greater cost to the consumer and the producer in all scenarios and lower carbon emissions than the scenarios without the 20% headroom.

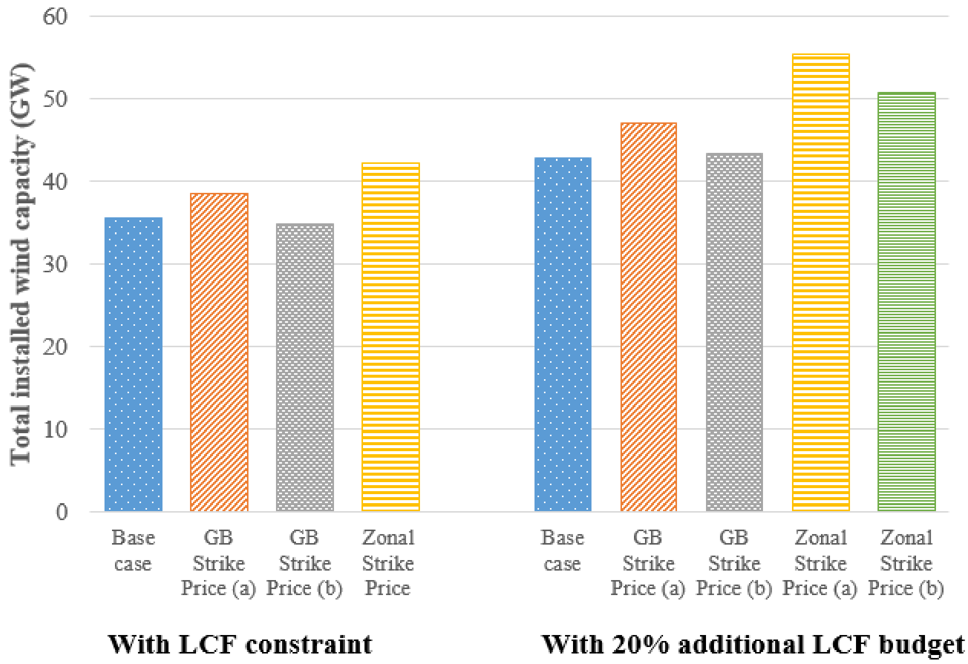


Figure 33 – Total installed wind capacity for all of the scenarios, from an objective function maximising profits to generators, with revenue payments and with and without the 20% additional LCF budget

5.3.2. Sensitivity Analysis Results – Western HVDC Link

This final sensitivity analysis investigates the impact of additional transmission capacity on the base case and zonal scenario results. As with the previous sensitivity case, a profit maximisation objective function is used. The National Grid B6 boundary data from 2014 [214] has 3.3GW transfer capacity, which is the figure that has been used in all of the previous model runs. This set of model runs also includes the series and shunt compensation works in 2016, increasing the transfer capacity by an additional 1GW in model year 2, and the Western HVDC Link, increasing the B6 transfer capacity by 2.2GW in 2018, taking the total transfer capacity to 6.5GW in model year 4. This has been done by altering the $PTC_{y,b}$ term in the transfer capacity constraint in equation (4). Figure 34 shows the resultant six-year average revenue streams from SRMC and top-up payments in each of the scenarios. In this set of results, a case has again been revealed in which both the GB strike price scenario and the Zonal strike price scenario SRMC iteration processes have not converged to a single solution. Market splitting occurs in every year in the GB strike price and Zonal strike price (b) solutions, and not at all in the GB strike price and the Zonal strike price (a) solutions. This failure for the iterative process to converge to a single solution is discussed further in section 5.4. It is interesting to note that the six year average SRMCs in Figure 34 are the same as those in , as in both cases the input reference prices to iteration (a) are those representing the marginal price of CCGT and the output results of these runs install enough wind generation in the Scottish node to result in price splitting.

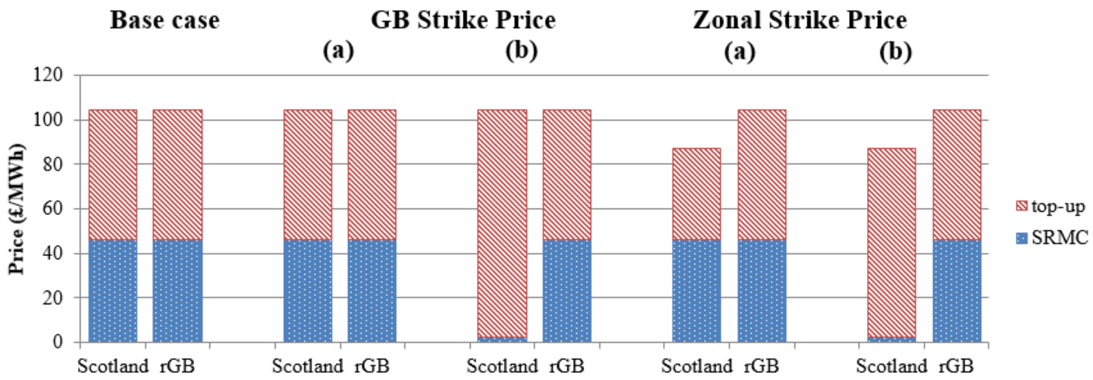


Figure 34 - Resultant model average SRMC and top-up payments for each zone in each of the scenarios, from an objective function maximising profits to generators, with revenue payments and additional transfer capacity due to the Western HVDC Link

Figure 35 and Figure 36 show the total installed wind capacity in each model year and the location of the total installed wind capacity in the final model year for all of the solutions respectively. It can be seen that the base case scenario results are unchanged from before, as this scenario is run unconstrained. In both the GB strike price (a) and Zonal Strike price (a) scenarios, SRMCs are set assuming that CCGT is the marginal generator in each year. Most of the wind generation installed in these scenarios is in Scotland, in year 1 until the transmission constraint has been met and then again in years 2 and 4 where the transfer capacity increases. The maximum amount of wind capacity is installed in Scotland in each of these years until the transmission constraint has been met, with the additional wind capacity installed in rGB until the LCF constraint has been met.

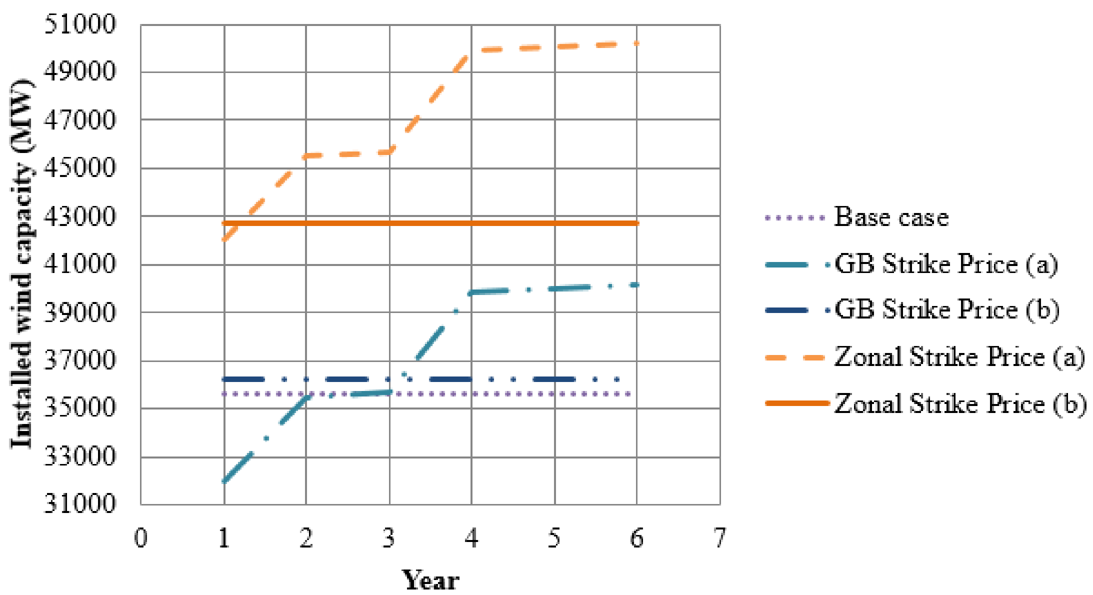


Figure 35 – Installed wind capacity in each year for all of the scenarios, from an objective function maximising profits to generators, with revenues payments and additional transfer capacity due to the Western HVDC Link

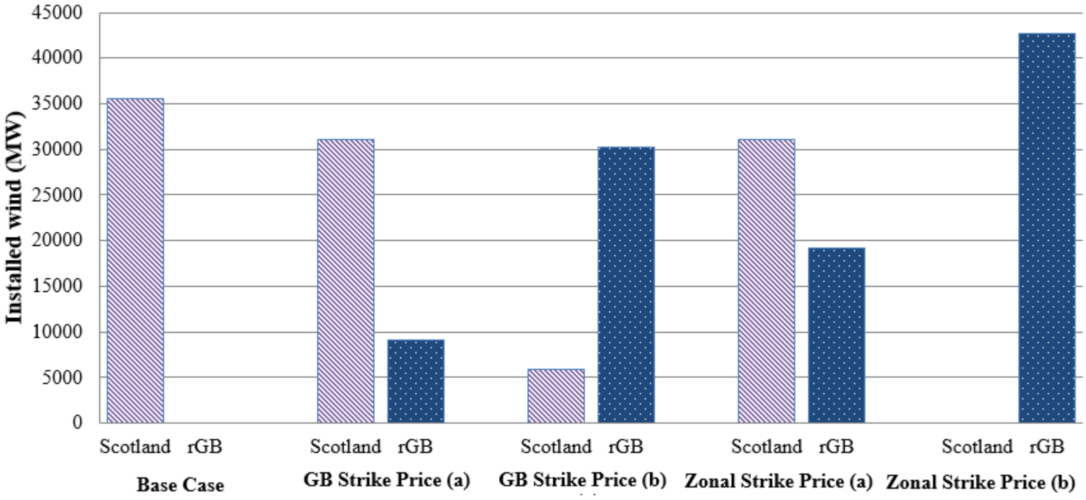


Figure 36 - Total installed capacity over the seven-year modelling horizon in Scotland and rGB in all scenarios, from an objective function maximising profits to generators, with revenue payments and additional transfer capacity due to the Western HVDC Link

In this case, the iteration process has not converged in both of the zonal scenarios. In both cases, the high installed capacity of wind in the Scottish zone in the (a) iteration causes market splitting in every year and low output zonal SRMC's in Scotland. The following iteration for these scenarios runs with top-up payments to Scottish wind generation calculated from these low zonal SRMCs. These comparatively higher top-up payments to wind in the Scottish zone mean that it is preferable within the profit maximisation to install wind in rGB, as wind generates a higher profit per MWh than CCGT and more wind can be installed in rGB before meeting the LCF constraint.

Figure 37 compares the installed wind capacity results from the model runs with the additional transfer capacity to the previous results from section 5.2. It can be seen that the all of the results have a greater amount of installed wind capacity in the final model year with the additional transfer capacity, as higher amounts of installed capacity occur in the later years where the transmission constraint increases. Due to this the model solutions with the additional transfer capacity also produce higher cost to the consumer and producer and lower carbon emissions than the previous solutions without the additional transfer capacity.

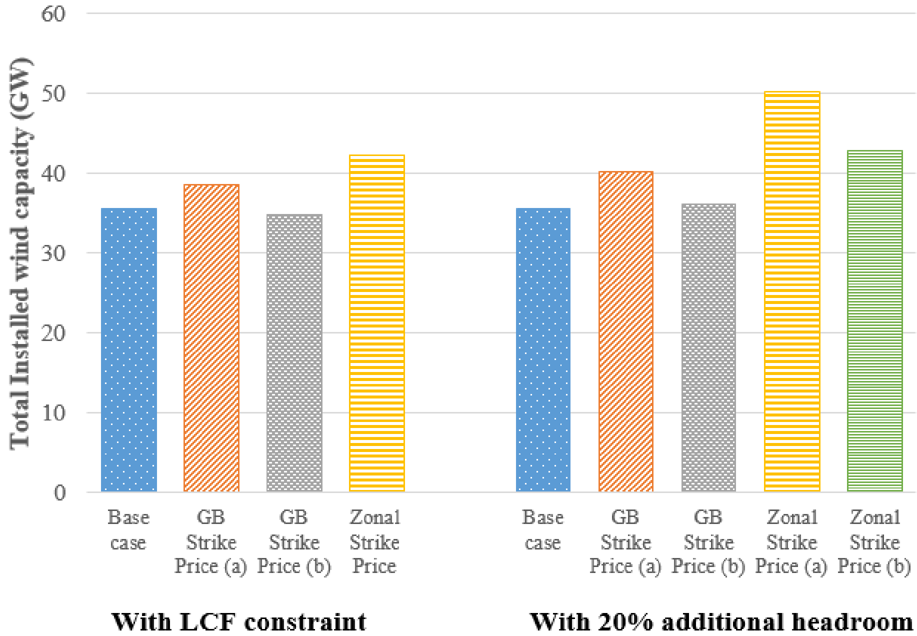


Figure 37 - Total installed wind capacity for all of the scenarios, from an objective function maximising profits to generators, with revenue payments and with and without the additional transfer capacity due to the Western HVDC Link.

5.4. Discussion

5.4.1. Key results

The previous sections have displayed the key results for each of the scenarios in both sets of model runs featured in this chapter: minimum cost to society and maximum profit to generators. Due to the simplifications associated with modelling the GB system in the two node solver (as two nodes, with two types of generation capacity and with two demand blocks) these results are best considered in terms of scenario comparison. As such the previous sections have discussed the qualitative difference in results between scenarios rather than focusing on the quantitative figures coming out of the model.

In these results, the base case scenario installed wind capacity is always entirely in Scotland, as the higher Scottish capacity factor results in a lower cost per MWh of generation produced and transmission constraints are not modelled. However, it has been seen that the installed capacity of wind differs greatly between scenarios, as well as the location of the installed wind capacity. The maximum profit to the producer results have noticeably higher installed wind capacity than the minimum cost to society results due to the comparatively higher profits associated with subsidised wind generation. The zonal scenarios are consistently cheaper for the consumer overall compared with the base case scenarios because the lower zonal revenues in Scotland at times of market splitting lead to lower costs for the consumer. The cost to the producer differs based on the installed capacity of wind, with higher costs to the producer in scenarios with higher installed wind capacity, as wind is comparatively more expensive to install and dispatch compared to CCGT. It can be seen that the cost to the consumer is consistently lower than the cost to the producer for every results set. This would seem to be counterintuitive, as in reality the producers costs have to be recovered and some net profit generated for production to continue. The difference in these costs is due to the fact that the two zone solver has been run assuming perfect competition with generators bidding in and gaining their short-term costs as market revenues. Wind generation receives subsidies in the form of CfD top-up payments so that it can gain its long-term costs, but CCGT generation does not. This is discussed more fully in section 5.4.4.

It is important to be careful when interpreting the results produced by the two zone solver, however. The objective function minimises all costs (including negative 'payments' to generators) while meeting the input constraints which best represent each scenario. When comparing results it is worth keeping in mind that these constraints are causing the differences between the scenarios results, and worth discussing how well these constraints represent real life systems. For example, using the Levy Control Framework constraint to set the minimum total spend on renewable generation is required in the cost minimisation scenario to ensure that the model invests in renewable generation in addition to the much cheaper CCGT. In reality the LCF budget could be under- or over-spent due to the inaccuracies in the prediction of market prices within the 15 year CfD timeframe. The limitations involved with using this model are discussed further in section 5.4.4.

Another interesting result is that the zonal scenario results differed greatly due to the model set-up: with an objective function minimising cost to society or maximising profit to generators. Figure 38 shows the installed wind capacity results for the GB strike price scenario for both of these different model set-ups and Figure 39 shows the installed wind capacity results for the Zonal strike price scenario. The base case installed capacity results remained the same in each case, with all of the installed wind capacity occurring in Scotland, as this produces a lower overall cost compared with installing wind in rGB and there are no transmission constraints limiting dispatch from Scottish generation. These graphs illustrate the effect that changes in the objective function set-up have on the zonal results.

In Figure 38 it can be seen that the GB strike price scenario results for the first iteration (a) for the minimum cost objective function have wind generation installed in both of the Scottish and rGB zones, whereas in iteration (b), wind is only installed in the Scottish zone. Both of these iterations have market splitting in some model years, and so SRMCs in the Scottish zone are lower than those in the rGB zone. In this case of the second iteration (b), the input SRMCs in Scotland are much lower than those in rGB and so the top-up payment to the GB-wide strike price is higher in the Scottish zone than in the Scottish zone previously in iteration (a). In the minimum cost to society case the total top-up is also to be minimised, and so wind generation is entirely installed in Scotland until the LCF constraint is met. In the maximum profit to the producer results, the two iterations again differ greatly in their results. The first iteration (a) is run from SRMCs assuming CCGT is the marginal generator in both zones. Wind is installed in the Scottish zone until the transmission constraint in met, and then in the rGB zone until the LCF constraint is met. The second iteration (b) produces very different results. These results are potentially more interesting as they explore the possible investment profile with low Scottish zonal prices. In this case the input SRMCs in Scotland are much lower than those in rGB and so the top-up payments to the GB strike price are much higher in the Scottish zone. As wind generation creates greater revenues per MWh, in this iteration wind is installed in rGB to a much greater proportion as a greater amount can be dispatched before hitting the LCF constraint.

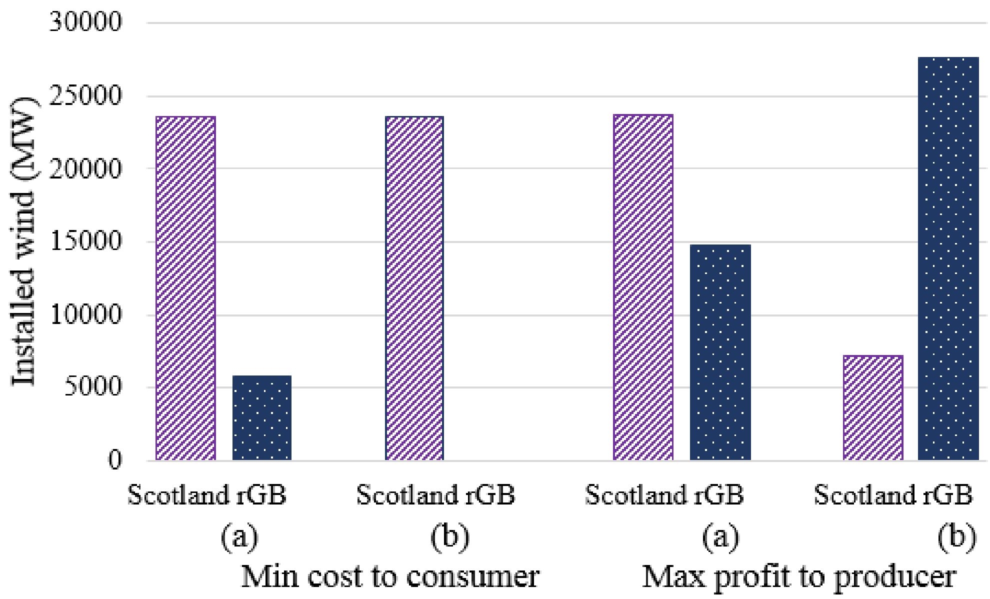


Figure 38 – Installed wind capacity results for the GB strike price scenario for both of the different model set-ups

In Figure 39 it can be seen that different installed capacity results are produced for the minimum cost to society and the maximum profit to producers model set-ups for the Zonal strike price scenario. The minimum cost to the consumer results install most of the wind capacity in Scotland, because when minimising cost to the consumer, generation in Scotland gains lower overall revenues (and thus imposes less cost to the consumer) and so as much capacity is installed in Scotland as possible, limited by the transmission constraint. In the case of maximum profit to the producer, the revenue payments are higher in rGB and so capacity is installed in rGB where possible. A small amount of wind is still installed in Scotland to meet demand in the off-peak block entirely from Scottish wind and imports from rGB.

It can be concluded that the difference in objective function set-up impacts greatly on the final results, with markedly different installed generation capacity results produced for the zonal scenarios depending on the objective function set up. This is a particularly interesting result as long term investment models used to investigate the impacts of different policy measures are for the most part cost minimisation models, as shown in Section 4.1. However, it could be argued that profit maximisation models better represent project developers investment decisions in real life liberalised markets. As such, using cost minimisation models could produce results which are not consistent with real life decision making, which would be of less value to policy makers.

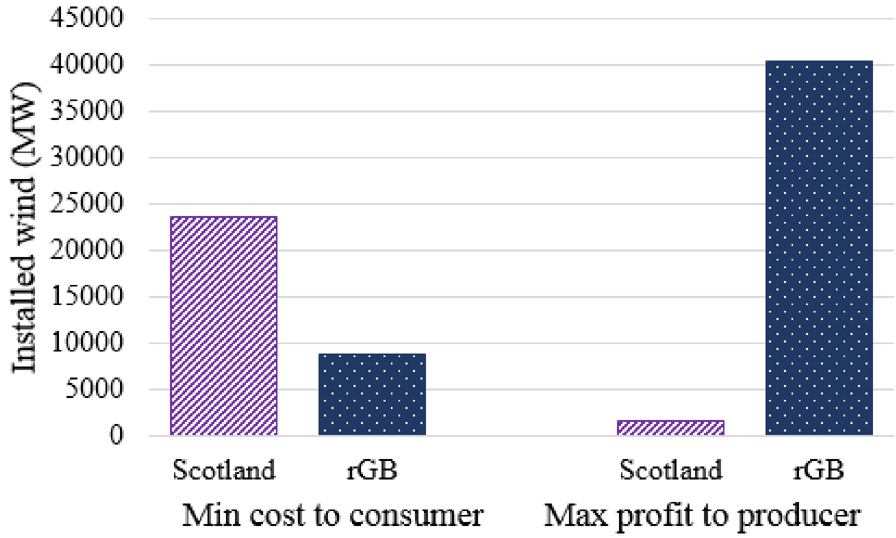


Figure 39 – Installed wind capacity results for the Zonal strike price scenario for both of the different model set-ups

5.4.2. Model convergence

Several scenario results have been highlighted in which the SRMC and top-up payment iterative calculation failed to converge. This occurred in the GB strike price scenario in every model run, and in the zonal scenarios in the sensitivity analyses.

In both of these results sets, the model fails to produce a single solution due to the interaction between the LCF limit constraint and the CfD mechanism. The top-up payments (difference between the strike price and zonal price) are calculated using the output zonal SRMC from one iteration as the input reference price for the following iteration, with the zonal SRMC calculation based on the amount of wind generation in each zone when a transmission constraint is present, as explained in more detail in section 4.2.1. The LCF constraint limits the total top-up, and so a feedback loop has been created that results in wind being installed where SRMCs are high and top-up payments are low to meet the LCF limit, which in turn lowers the SRMCs and raises the top-up payments for the next iteration, resulting in a scenario where convergence is not possible.

Figure 40 illustrates the issue preventing convergence between iterations for some scenarios. When total model wind penetration is greater than 27.30% wind generation becomes the price maker for the Scottish off-peak block, meaning that the SRMC drops to the marginal price of wind in this block, and as the off-peak block accounts for 95% of the year the average SRMC the average SRMC drops to less than £2.5/MWh. As shown in Figure 40 the SRMC can only take one of two values in each year in the Scottish zone, depending on if CCGT or wind is setting the price in the off-peak block. As previously discussed, CCGT is always used to meet demand in the peak block because of the comparably cheaper running costs. As such, a non-convex relationship between the proportion of installed capacity from wind generation and the resultant SRMC occurs. Although each separate model run converges to a solution in terms of installed capacity and dispatch, the iteration process alternates between two output values for Scottish SRMC without reaching a single solution, depending on the percentage installed wind capacity in Scotland. If there were a more varied mix of generation types or a greater amount of demand blocks included in the model, a smoother variation of SRMC would occur and this problem would not have arisen. Limitations on the number of variables able to be included within the excel solver prevented a more detailed model from being created for this work. This failure to converge between model iterations for this simple solver has also been discussed in Pennock et al [176].

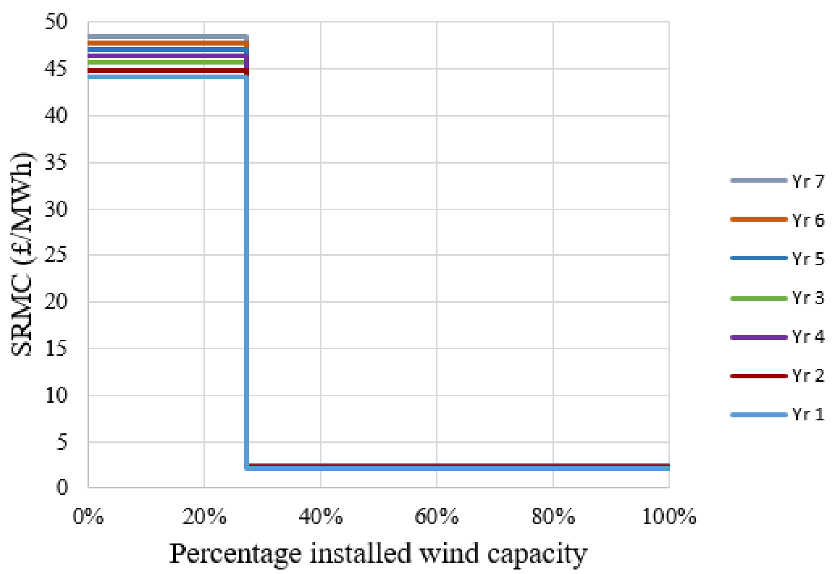


Figure 40 – Percentage installed wind capacity versus SRMC in the Scottish zone

5.4.3. Scenario limitations

Each scenario modelled within these results sets have their own limitations. This section will discuss key limitations with the base case and zonal scenario set-ups.

The unconstrained base case has been modelled to represent trading within GB, which occurs without taking account of transmission constraints, but does not accurately represent the balancing mechanism or the costs associated with this. In reality, there would be additional costs associated with the transmission network, balancing and redispatch [215]. In the real world, transmission constraints exist on different network boundaries in Scotland and rGB at different times of the year and increased installed capacity of generation in Scotland would result in greater instances of redispatch and increased cost to the consumer [216].

This additional cost associated with redispatch can be approximated with regards to the base case scenario results shown in the previous sections. In the base case scenario for the maximum profit to generators results set, the additional wind generation over the six year modelling horizon surpassing the B6 boundary transmission constraint set in the zonal scenarios was 237.82TWh. This equates to 10.92% of the total GB generation over this modelling period. Assuming that in reality this additional wind generation would be constrained and replaced by dispatchable CCGT generation, the additional cost of this transmission constraint would be the dispatch costs of the additional CCGT generation required to meet the additional demand resulting from the constrained generation, plus bids accepted from wind farms in order to reduce their output, the price per MWh of which would be expected to be at least equal to the lost revenue resulting from reduced production, i.e. equal to the strike price. Within the model, CCGT has a levelised cost of £45.99/MWh, resulting in an additional £10.94bn in cost to the consumer due to the transmission constraint. Applying this additional cost to the consumer to the results in Section 5.3.2 gives an overall cost to the consumer for the base case scenarios of £143.97bn, making the base case 9.1% more expensive to the consumer than the next most expensive scenario (Zonal strike price – max profit to producer).

The GB strike price scenario represents a case in which zonal pricing has been introduced but a single auction process is still used to decide CfD strike prices, with generation in both zones gaining top-up payments to a single GB-wide strike price from zonal wholesale prices. The Zonal strike price scenario represents a case in which zonal pricing has been introduced and generation in either zone gains a strike price specific to that zone. In reality this could take the form of two separate CfD auctions for either zone with their own budget and MW requirements. For the purpose of this work, the Zonal strike price scenario has been represented by calculating top-up payments to generation in either zone based on the LCOE of wind generation in each zone. With varying capacity factors but equal costs, the LCOE is less in Scotland where annual energy production per installed MW of capacity is higher. This produces comparatively lower overall revenues to wind generation in Scotland compared with wind generation in rGB. This is an 'ideal' representation of CfD auctions, as in reality Scottish generation would have to bid for separate strike prices without perfect foresight as to when and if market splitting would take place.

The zonal scenarios are modelled with revenue payments included in the profit maximisation model set-up. This is because it is arguable that representing a scenario without revenue payments does not truly represent the potential costs to the consumer and profits for the producer resulting from zonal wholesale prices. If revenue payments were not included in the zonal scenarios then higher top-up payments to Scottish generators would occur at times of market splitting, when in reality the overall revenues per MWh including the wholesale price would be the same for generators in both zones.

5.4.4. Model limitations

This simple two-node model has allowed for a qualitative comparative discussion of the results, with the simplified set up making it clear which constraints are being hit in each year and why each type of generation is installed in a particular area in a particular year. As the model has been kept fairly simple, a discussion of its limitations is also useful. A number of assumptions, simplifications and limitations have been involved in the creation of this model. Generator availability is modelled using generator capacity factors, which does not represent thermal generator start-up, ramping rates, forced outages and scheduling of reserve or the stochasticity of the wind resource, in addition to the costs associated with these. The higher wind resource in Scotland is represented by a higher capacity factor for Scottish wind generation compared with wind generation in rGB. While on average this might be the case, it will not be the case for every wind farm, as capacity factor is highly dependent on site selection. Both wind and CCGT plants are assumed to have 25 year lifetimes for the amortisation calculations, which will not be accurate for all generators. In addition to this, the model primarily focuses on direct costs, such as capital costs associated with generator installation and operation and maintenance costs. However, there are various indirect costs which the model does not include, as these are much more difficult to estimate. Indirect costs not modelled include balancing costs, connection charges, transmission network use of system charges, market transaction costs and policy implementation costs (e.g. additional costs associated with the capacity market). By not including all of the costs associated with generator operation, the model could produce results which favour one type of generation or location which does not represent a realistic picture of investor decisions. This impact could be minimal, however, as it has been stated that indirect costs are comparatively much smaller than direct costs, making up less than 10% of total costs [217].

The transmission system and the physical constraints related to its operation are heavily simplified in the two-zone solver, with no representation of transmission constraints in the base case and only a single transmission constraint in the zonal scenarios at the Scotland-rGB boundary. This is to represent the way that wholesale markets currently trade in GB without price impacts due to generator location, and the way that zonal pricing could be introduced to GB with two separate zonal prices occurs during times of congestion and market splitting. The costs associated with redispatch and the balancing mechanism are not modelled here, but have been discussed and an example calculated in Section 5.4.3.

The installed capacities of two types of generation do not properly represent the generation mix in GB, nor do two demand blocks represent a realistic demand profile. These model inputs have been kept deliberately simple in order to illustrate the impacts that zonal pricing could have on investment in generation in GB, where a simple choice is made between a low carbon generator and a carbon producing generator. As such, the results have been discussed qualitatively with regards to which locations more or less wind generation has been installed. In addition to these simplifications, the number of constraints allowed within the excel linear solver was a highly limiting factor once the model had been developed, causing the model runs to be over only six model years, when a longer modelling horizon would have given a more interesting solution. The constraints also limited the granularity of the representation of demand and wind resource. Only a peak and an off-peak demand block could be included in the solver. Modelling more demand blocks with different availability for wind generation would have been a more realistic way of modelling the variable wind resource. For example, if a short block at peak and a short block at off-peak were included with low wind resource, additional CCGT would have to be built to meet demand at these times. Modelling these scenarios also included having to represent the LCF as a hard equality constraint so that the model would invest in some low carbon generation and represent the generation mix and policy goals of the UK. It could be argued that this explicit LCF constraint over-constrains the model, leaving little choice as to the final generation mix.

The GB electricity market is mostly bilateral and comparatively illiquid [39], whereas the market represented by this two node solver assumes perfect competition, in which generation bids into the market at its short run costs and clears at the cheapest option available to meet demand at each model time-step. Output short run marginal costs (SRMCs) are used to represent revenues to generators and calculate CfD top-up payments, when in reality there are various other factors impacting the price of electricity e.g supply chain limitations, market liquidity and power purchase agreement (PPA) contract conditions. This work also assumes that changes in zonal prices are reflected in the cost of electricity to the consumer. In reality reductions in wholesale prices of electricity are often argued to be absorbed into the profits of the electricity supplier. An example of this is occurred in 2014 when suppliers in GB were accused by Ofgem of not reducing tariffs to represent the reduction of forward prices for gas and electricity on the wholesale market [218].

The use of marginal short-run costs in representing market revenues has resulted in overall costs to the consumer being less than overall costs to the producer. In reality it would be expected that the producers costs would be recovered and some profit generated. However as the largest revenues that a CCGT generator can receive within the two zone solver is that of their short run costs, the recovery of lifetime costs is not being represented. In reality, generators recover their long term costs by bidding into competitive markets or entering PPA agreements at higher prices than their short run costs and through mechanisms such as balancing markets, ancillary services and reserves markets and capacity markets. Figure 41 and Figure 42 below represent the overall cash flows (sources of revenues and outgoings) of

CCGT and wind respectively, both in reality within GB and as represented in the two node solver. It can be seen from Figure 41 that only the marginal short run costs are used to represent revenues for CCGT within the two node solver, which would cover fuel costs and operational costs, but not the lifetime costs associated with CAPEX payback. However, for wind within the two zone solver (illustrated in Figure 42) the representations of revenues and subsidy payments are sufficient to cover long term costs. As within the two zone solver CCGT is incapable of recovering its long term costs through the revenues represented by marginal short run costs it is arguable that the representation of additional sources of revenue should be included, such as from the capacity market. However, for the purpose of this work, as the long term costs of CCGT are still cheaper than those of wind generators it is unlikely that adding additional costs and sources of revenues would have majorly impacted on the overall results.

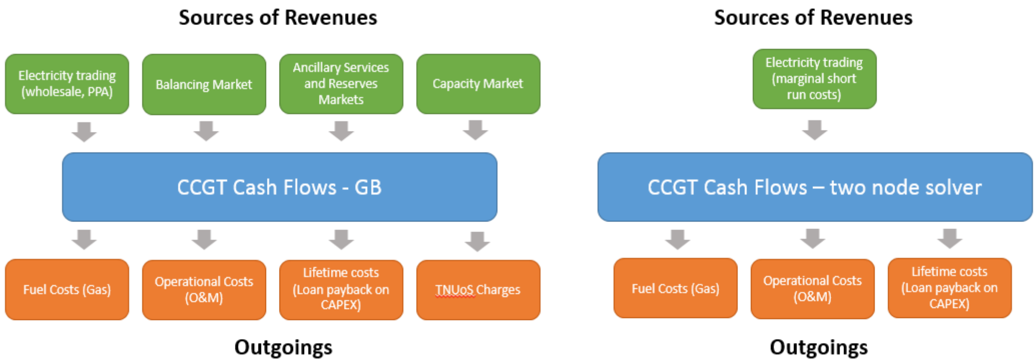


Figure 41 – Block diagrams of CCGT cash flows in GB (left) and those represented in the two node solver (right)

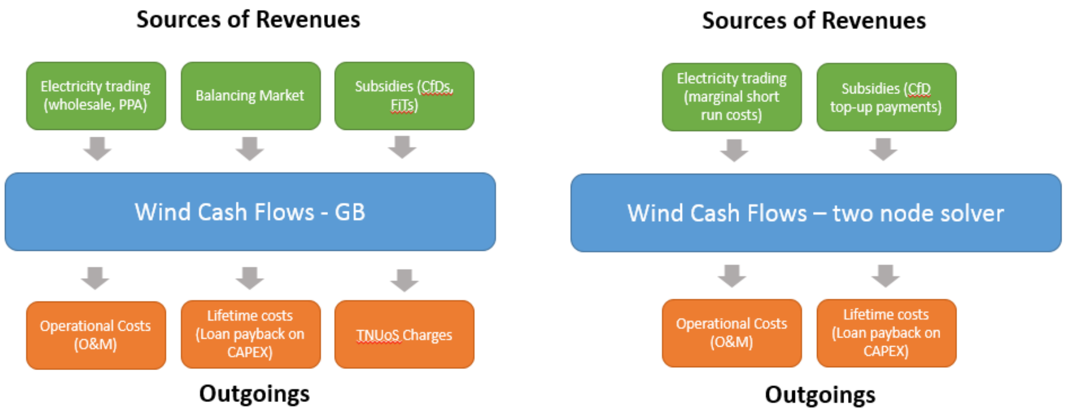


Figure 42 – Block diagrams of wind cash flows in GB (left) and those represented in the two node solver (right)

One key limitation of the model has been its inability to converge the SRMC iteration process for all simulations due to the non-convex function between the proportion of installed capacity from wind and the output SRMC. This highlights the issues associated with using a cost-minimisation algorithm with CfDs and generator revenues as negative cost terms which relies on an external iterative process to calculate top-up payments, which themselves are also constrained by the LCF budget. This inability to converge could potentially have been avoided if more generation types were included in the model, giving more than two potential market prices for electricity. Also, the inclusion of more demand blocks to better represent the demand curve could have resulted in more consistent average annual SRMCs. This would also involve reducing the number of model years reprresented, as the number of constraints able to be included in the excel solver was a key limitation of this method. It was not possible to explore these options more fully in this work due to time constraints.

In the literature, many papers discuss the social welfare in terms of the consumer and the producer surplus [169],[219], i.e. the difference between the energy price and the price which consumers and producers would be willing to accept. The modelling completed in this work does not produce results with respect to consumer surplus as there are no assumptions made in these models about how much consumers would be willing to pay for their energy. In the absence of a well-defined and agreed demand curve, the minimisation of the total cost of generation to meet demand within certain constraints is used to represent the most cost effective solution. Also although profit maximisation scenarios occur with a representation of wholesale revenues based on the marginal price calculated from the short run costs of the marginal generator, there is not enough complexity in the two zone solver to properly define producer surplus as investment decisions are made only between onshore wind and CCGT generation.

Chapter 6.

Modelling zonal pricing in GB – SEDM

This chapter features results from the Scottish Electricity Dispatch Model (SEDM). The SEDM is a sophisticated, professionally developed model housed at the Scottish Government [220]. As such, the SEDM has been developed as a cost-minimisation power system optimisation model with the aim of increased resolution over issues related to the Scottish section of the GB power system. Revenues from the wholesale market are not represented in the SEDM objective function, and so the impact from zonal pricing is not explored in the same way as in the two node model in the previous chapter. As such, SEDM does not model profit maximisation including the zonal revenues gained from wholesale market trading. However, SEDM can still be used to model the difference in subsidy payments caused by different zonal prices, and the impact that this has on the long term investment in generation capacity, and still produces interesting and relevant results for this work. The limitations associated with the SEDM model set-up is discussed in more detail in Section 6.3 and Section 7.2.2. CfD top-up payments are represented by a negative cost term within an objective function minimising the cost of installing and dispatching generation to meet GB demand, subject to various constraints as outlined in Chapter 4.

This chapter first displays results illustrating the SEDM's ability to explore the impact of policy drivers using scenario analysis. Combinations of implicit and explicit representations of carbon-reduction policies are included within the model set-up, namely representations of CfD top-up payments to renewable generation, additional costs associated with carbon production and explicit emissions limits. Next, a representation of the zonal pricing scenarios discussed in Chapters 4 and 5 is modelled and the results are compared with a base case scenario representing trading in GB at present. The scenarios explored in this chapter are summarised in Table 13. These results are then discussed in section 6.3 in relation to the modelling limitations associated with the SEDM.

Table 13 – Scenarios investigated using the SEDM

Scenario	Carbon reduction policy representation	Strike price	Transmission capacity
Carbon Reduction Scenarios			
Contracts for difference	CfD top-up payments	GB-wide	Fully constrained
Carbon Pricing	CfD top-up payments, carbon pricing	GB-wide	Fully constrained
Emissions limits	CfD top-up payments, carbon pricing, explicit emissions limits	GB-wide	Fully constrained
Zonal Pricing Scenarios			
Base case	CfD top-up payments, carbon pricing	GB-wide	Unconstrained
GB strike price	CfD top-up payments, carbon pricing	GB-wide	3.3 GW at B6 boundary
Zonal strike price	CfD top-up payments, carbon pricing	Zonal	3.3 GW at B6 boundary

6.1. Carbon Reduction Scenarios

In this section, results of SEDM runs investigating the impact of low carbon policies on carbon emissions, generation portfolios and system costs are displayed to illustrate the capabilities of the SEDM in representing different policy mechanisms. The SEDM objective function and relevant constraints have been described previously in (18) - (36) in Chapter 4 and the model set up for the carbon reduction scenarios has been described in section 4.3.2

Three sets of outputs for the three scenarios modelled are shown here for each model year from 2015 to 2050. These are: total installed generation capacity, installed renewable generation capacity and CO_2 emissions. Installed capacity in 2015 represents the historical generation fleet in GB in 2015, whilst future years include the model investment decisions for new generation capacity in subsequent years and the retirement of existing plant. Some planned new installed capacity is also included between 2015-2020 as an input.

Figure 43 shows the total installed renewable capacity for each of the carbon reduction scenarios. The contracts for difference results show continued growth in renewables until 2020 due to wind projects already in development and planning, and then effectively no further investment in renewables after 2020. The reduction in capacity in future years is due to the retirement of existing capacity. The carbon pricing scenario shows a moderate increase in renewable installed capacity until the early 2020s, which is noticeably larger than the low carbon subsidies scenario by 2020. In the carbon pricing scenario results there follows a little new capacity development until the late 2020s and then a sharp peak in development at 2030 due to the higher carbon price coming into effect in this year. There is then a steady decline in renewable capacity until 2050, as capacity is retired. The carbon pricing scenario has 37.9% greater installed capacity than the low carbon subsidies scenario by 2030 and 425.7% by 2050. Other, non renewable, low carbon generation (nuclear and carbon capture and storage technologies) also increase in installed capacity, by 178.9% in 2050 compared with the contracts for difference scenario.

In Figure 43 the emissions limits scenario shows a similar trajectory to the carbon pricing scenario until 2030. This is due to the fact that both scenarios include carbon pricing across the period, whilst emissions limits are only binding after 2030. For 2028 to 2032 the emissions limits scenario sees a huge expansion of renewable generation with installed capacity rising by approximately 23GW over four years, as the model invests to meet the emissions targets in 2030 and beyond. Renewable capacity then declines due to retirement of existing assets until 2045, before increasing again until 2050. The emissions limits scenario has 54.5% greater installed capacity of renewables by 2030 when compared with the base case, and this figure is 1812% by 2050 – 81.7GW compared with 4.3GW. This scenario also has an increase of non-renewable low carbon technologies (nuclear, CCS) by 2050 of 243.4% compared with the contracts for difference scenario.

Figure 43 - Installed capacity from renewable generation for the contracts for difference, carbon pricing and emissions limits scenarios, from 2014-2050

The difference in installed capacity between these three scenarios is because without any financial incentives or constraints for low carbon technologies, the model will invest in the generation with the lowest long run costs (coal and gas) rather than renewable generation with comparatively higher long run costs. Carbon pricing and emissions limits scenarios are similar until 2030 because prior to this the emissions limits are above the level achieved via the use of carbon pricing and the residual impact of existing renewable generation.

Whilst Figure 43 shows the capacity of all renewable generation, it is interesting to identify the component of this provided by wind, which uses locational data for available resource in the

SEDM. Figure 44 illustrates the installed capacity from wind generation in each of the scenarios. In this case the emissions limits and carbon pricing scenarios produce similar results until 2040, at which point there is 255% more installed wind capacity when compared with the low carbon subsidies scenario. When compared with Figure 43 it is clear that a major component of the spike in renewable capacity is the emissions limits scenario at 2030 is due to technologies other than wind. The model contains build limits for each technology to represent supply chain constraints. As such, the model must invest in a varied mix of low carbon technologies such as solar PV, biomass, wave and tidal. In this particular case all the Round 1 and 2 offshore wind projects input to the model as candidate generation are built to maximum capacity, as well as the Scottish Round 3 offshore wind projects. At this point the model builds solar power in the south of England rather than investing in the more southerly Round 3 offshore sites, as the lower capacity factors compared with the Scottish wind resource result in an increased levelised cost.

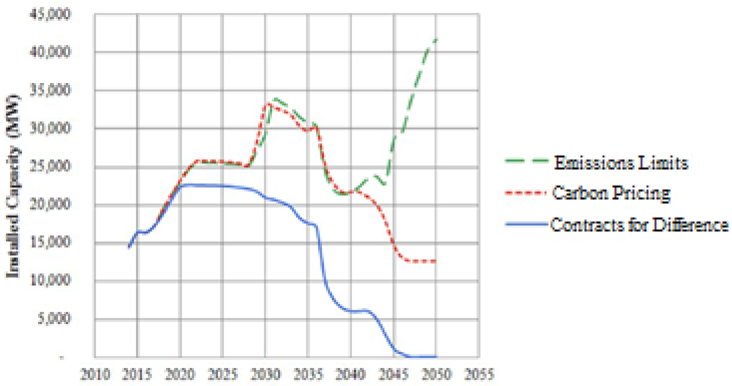


Figure 44 – Installed capacity from wind generation for the contracts for difference, carbon pricing and emissions limits scenarios from 2014-2050

Figure 45 shows the annual CO_2 emissions for each of the three scenarios. It can be seen that the low carbon subsidies scenario annual emissions increase steadily from 2025, once the renewables projects currently in planning have been completed. In the carbon pricing scenario annual emissions decline until 2023 and then remain fairly steady. In the emissions limits scenario annual emissions decline until 2030 before a shallower decline until 2050, meeting emissions targets constraints in each year. Carbon emissions are found to reduce by up to 95.6% by 2050 when comparing the emissions limits scenario with the contracts for difference scenario.

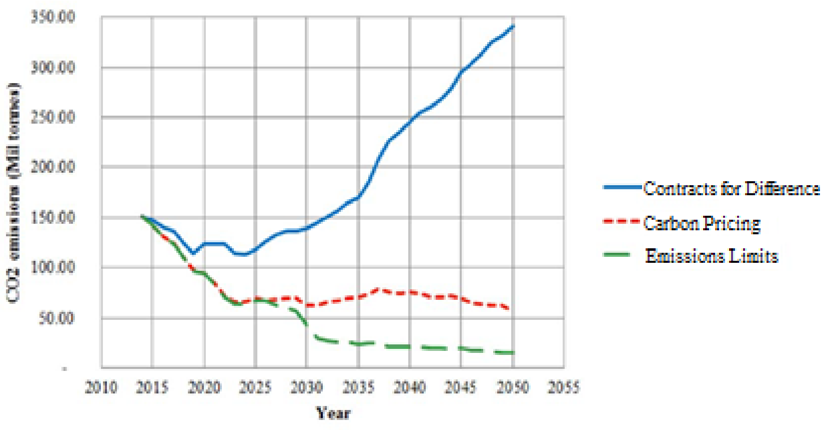


Figure 45 – Annual carbon emissions for the base case, carbon pricing and emissions limits scenarios, from 2014-2050

System costs increase by 23.4% between the emissions limits and the low carbon subsidies scenarios by 2050. This is due to the additional model constraints resulting in the investment of more expensive generation technologies, and there being no cost associated with carbon emissions in the contracts for difference scenario.

Overall the results suggest that long term carbon reduction will not occur in a simulation representing the current GB system and including current subsidies to low carbon technologies. Simulations representing policies such as carbon pricing or the legal enforcement of emissions limits did result in the reduction of carbon emissions, through increased investment in renewable and low carbon generation technologies. Only the results explicitly constrained to meet CCC emissions targets reached this goal.

6.2. Zonal Pricing Scenarios

This section will outline a representation of the zonal scenarios described in the previous chapters, using the SEDM. As discussed in detail in section 4.3.1, the SEDM objective function minimises the total cost of investing in and dispatching generation and transmission to meet GB demand up until 2035, including investment costs and variable and fixed generation costs. CfD subsidies are represented as a negative variable cost for low carbon generation, resulting in lifetime costs that are competitive with carbon producing generation. The SEDM set up for each of the zonal scenarios is described in detail in section 4.3.3.

For the zonal pricing scenarios, the SEDM has been run over twenty-two model years representing the generation mix in GB from 2014 up until 2035. The model has been run over less model years for the zonal scenarios compared with the carbon reduction scenarios to reduce simulation times and to keep results focused on a more relevant near-term time frame. Figure 46 and Table 14 show the average SRMC and top-up payments in each zone to an onshore wind generator with a strike price of £84.75 over the twenty-two year SEDM time horizon. It can be seen that market splitting has occurred in both of the zonal pricing scenarios, as the average SRMCs differ between the two zones. In the GB strike price scenario results market splitting occurs in fifteen of the twenty-two years in the model time horizon and in the Zonal strike price scenario results market splitting occurs in twelve of the twenty-two years.

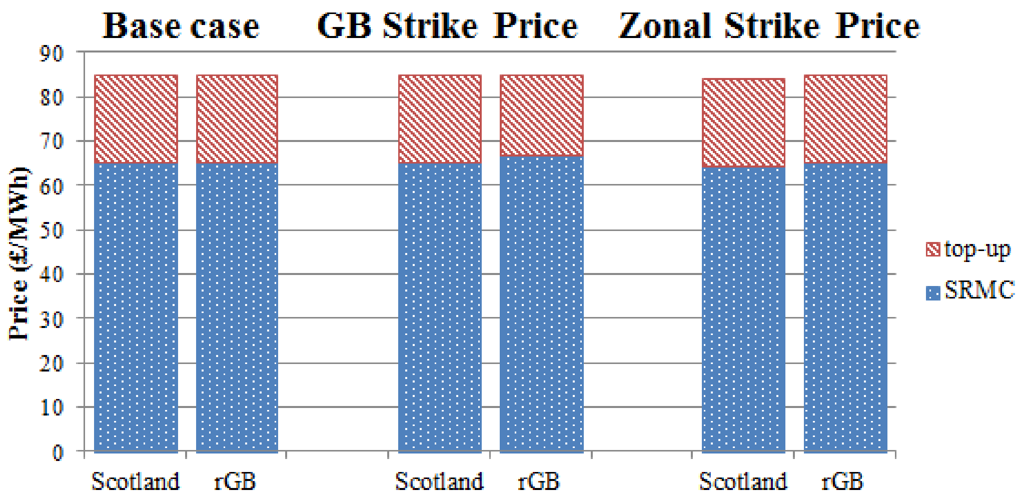


Figure 46 – Resultant SEDM average SRMC and top-up payments for each zone in each of the scenarios up until 2035

Table 14 – Values for resultant SEDM average SRMC and top-up payments for each zone in each of the scenarios up until 2035

(£/MWh)	Base Case		GB Strike Price		Zonal Strike Price	
	Scotland	rGB	Scotland	rGB	Scotland	rGB
SRMC	65.11	65.11	65.15	66.79	64.40	65.27
top-up	19.64	19.64	19.60	17.96	19.48	19.48

Figure 47 shows the installed low carbon capacity (made up of wind, hydro, biomass, marine, nuclear, CCS and solar PV generation) in each SEDM year and each of the scenarios. It can be seen that the base case scenario has a consistently greater installed capacity of low carbon generation than the zonal scenarios. Table 15 shows the installed capacity figures for both low carbon generators and carbon producing generators (made up of CCGT, OCGT and coal generation) in the final year of the SEDM time horizon. The GB strike price scenario has 4.48% less installed low carbon capacity than the base case by this year, and the zonal strike price scenario has 0.64% less installed low carbon capacity than the base case. This results in 9.02% greater installed carbon producing capacity in the GB strike price scenario compared with the base case and 0.68% greater installed carbon producing capacity in the Zonal strike price scenario compared with the base case.

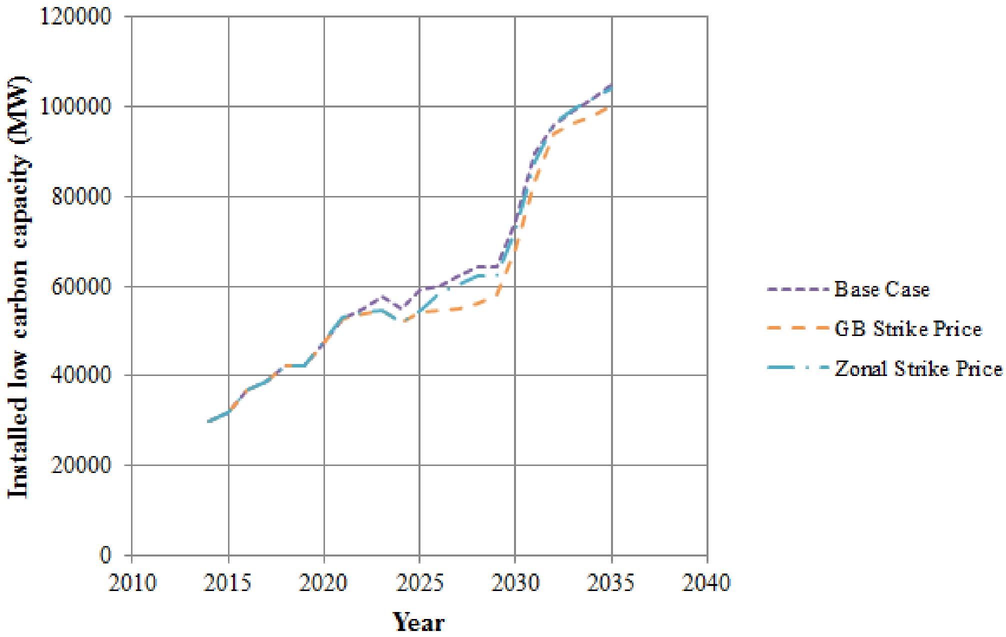


Figure 47 - Installed low carbon capacity in GB in each year for each of the scenarios up until 2035

Table 15 – low carbon and carbon producing installed capacity up until 2035 for the scenarios, and percentage comparison with base case

	Low carbon installed capacity (GW)	% diff from base case	Carbon producing installed capacity (GW)	% diff from base case
Base case	104.92	-	38.85	-
GB Strike Price	100.22	-4.48%	42.36	9.02%
Zonal Strike Price	104.24	-0.64%	39.11	0.68%

Table 16 shows the production from low carbon and carbon producing generation in MWh over the twenty-two year model time horizon. The comparative results with the base case are similar to the installed capacity results already discussed, with the GB strike price scenario producing 5.21% less low carbon generation and 6.89% more carbon producing generation than the base case and the Zonal strike price scenario producing 0.89% less low carbon generation and 1.27% more carbon producing generation than the base case.

Table 16 - low carbon and carbon producing generation up until 2035 for the scenarios, and percentage comparison with base case

	Low carbon generation (GWh)	% diff from base case	Carbon producing generation (GWh)	% diff from base case
Base case	4508722	-	3075132	-
GB Strike Price	4273786	-5.21%	3286950	6.89%
Zonal Strike Price	4468584	-0.89%	3114098	1.27%

Figure 48 shows the total installed low carbon capacity in each zone and scenario in the final year of the SEDM time horizon, split over the different technology types. Although the overall installed capacity of low carbon generation in the GB strike price scenario in Figure 47 is lower than the other two scenarios, it can be seen in Figure 48 that the GB strike price scenario has the highest Scottish low carbon installed capacity.

In Figure 48 the GB strike price scenario builds biomass, CCS and marine generation in Scotland, whereas in the other scenarios these technologies are built to a greater extent in rGB. This is because of the way that the GB strike price scenario has been set up, where low carbon generation in Scotland will gain a higher top-up payment due to the lower zonal price, and thus these generators look cheaper to build in Scotland than in rGB. As the objective function includes CfD top-up payments as a negative cost within the cost minimisation, the model will maximise the installed capacity in the region with the higher top-up payments. The types of generation chosen are modelled to be more dispatchable in the model than wind, and so will be able to generate in all blocks, including the low wind resource blocks. As such, these generators can still achieve a high enough capacity factor to be a more cost effective choice to install in Scotland rather than rGB. The limitations of modelling zonal pricing without revenue payments are discussed further in section 6.3.3. The results for other low carbon generation show more solar PV is built in rGB in all scenarios as the capacity factors are highest in the south of England, and CCS and nuclear are built in rGB as most of the candidate generation is located there for these technologies (all of the candidate generation in the case of nuclear, which has no candidate generators for new build nuclear in Scotland)

Looking at wind, which has the highest proportion of all of the installed low carbon generation technology types in GB, the installed capacity is lower in Scotland in the zonal scenarios when compared with the base case and higher in rGB in the zonal scenarios than in the base case, as shown in Figure 48. This is because the transmission constraint enabled in the zonal pricing scenarios means that wind generation in Scotland can only be used to power generation in rGB up until the transmission constraint hits, after which dispatch will be constrained and the capacity factor will reduce. The wind generation built in Scotland first invests in candidate generators with the highest capacity factors, for example Shetland where capacity factors are in excess of 50%, before investing in candidate generators located in areas with lower capacity factors. The SEDM also assumes that a sufficiently large connection between Shetland and the mainland exists, which is not currently the case.

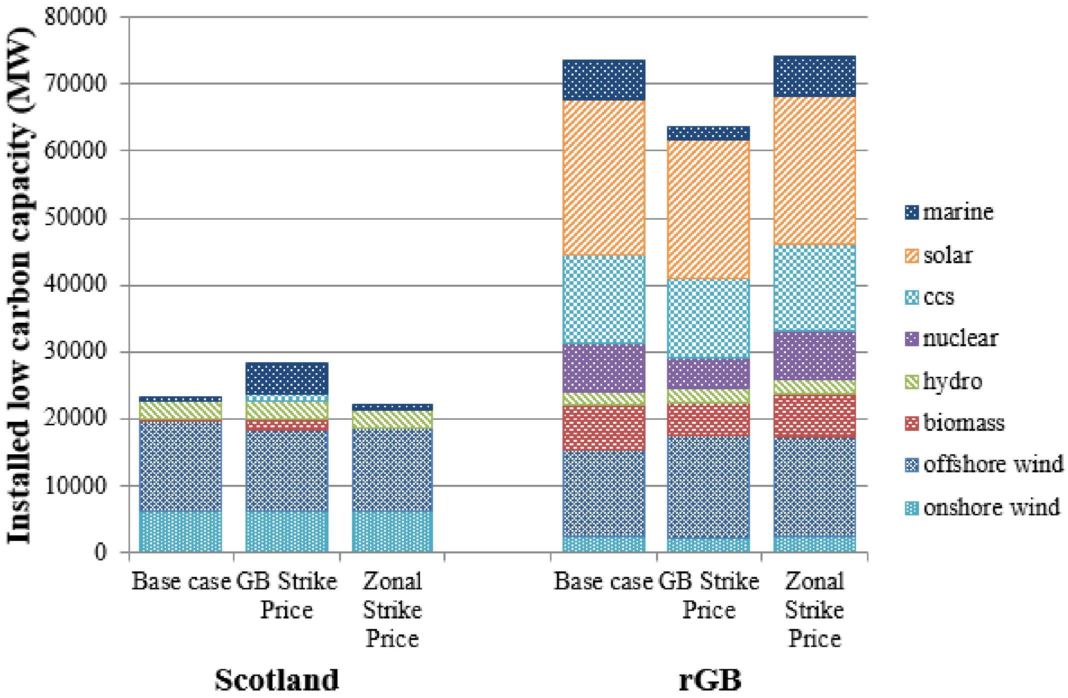


Figure 48 - Total installed low carbon capacity split by technology type over the twenty-two year modelling horizon in Scotland and rGB in each of the scenarios

Table 17 – total installed wind capacity, both onshore and offshore in the base case and zonal scenarios until 2035

Installed Capacity (GW)	Base Case		GB Strike Price		Zonal Strike Price	
	Scotland	rGB	Scotland	rGB	Scotland	rGB
onshore	6.41	2.45	6.41	2.20	6.41	2.45
offshore	13.44	12.40	12.45	14.20	11.97	14.44
Total	**19.85**	**14.85**	**18.86**	**16.40**	**18.38**	**16.89**

Table 18 shows the total installed wind capacity, percentage of installed wind capacity in Scotland, percentage of total energy production from wind, total cost to consumer, total cost to producer and total carbon emissions for each of the scenarios. The cost to the consumer is represented by the costs that will be reflected in the consumer's energy bills: the total market revenues plus the total spend on CfDs and ROCs. The cost to the producer is represented by the costs that the energy producer will incur, including capital costs, O&M costs, fuel costs and carbon costs.

Table 18 - Installed wind capacity, percentage of installed wind capacity in Scotland, percentage of generation from wind, total cost, subsidy spend and carbon emissions for the SEDM results to 2035

Results set	Installed wind capacity (GW)	Percentage of installed wind capacity in Scotland	percentage of total energy production from wind	Total cost to consumer (billion £)	Total cost to producer (billion £)	Total carbon emissions ($MtCO_2$)
Zonal pricing SEDM results						
Base case	34.70	57.21%	19.95%	694.74	500.29	1637.80
GB strike price	35.26	53.48%	19.67%	694.07	501.14	1728.00
Zonal strike price	35.27	52.11%	19.73%	693.43	500.74	1653.30

It can be seen that both of the zonal scenarios have a lesser total cost to the consumer and lesser proportion of installed wind capacity in Scotland than the base case, although the Zonal strike price scenario results are very similar to that of the base case. The GB strike price scenario results in 0.09% lower total cost to the consumer and 6.52% less installed wind capacity in Scotland than the base case and the Zonal strike price results in 0.19% lower total cost to the consumer and 8.91% less installed wind capacity in Scotland than the base case. Both of these scenarios also result in higher carbon emissions than the base case, with the GB strike price scenario resulting in 4.52% higher total carbon emissions than the base case, and the Zonal strike price results in 0.94% higher total carbon emissions than the base case, because of the difference in carbon producing generation due to transmission constraints.

In Table 18 the installed wind capacity results are slightly higher in the zonal pricing scenarios than in the base case scenario. Although the total installed wind is greater in the zonal pricing scenarios, the percentage of installed wind capacity in Scotland is less in both of the zonal scenarios compared with the base case. The percentage of total generation from wind is also greatest in the base case scenario, as the Scottish installed wind generation has a higher capacity factor than that installed in rGB. The total cost to the consumer and the total subsidy spend is less in both of the zonal scenarios compared with the base case, but the total carbon emissions and total cost to the producer are greater than the base case.

These results suggest that introducing zonal pricing to GB could reduce the amount of wind generation installed in Scotland. The base case has the highest proportion of installed wind in Scotland and produces the least total carbon emissions over the model lifetime, but does involve a higher total cost to the consumer due to the higher installed capacity of low carbon technologies, which have higher capital costs than the carbon producing technologies. These results are largely in agreement with the maximum profit two zone solver results in the previous chapter. However, as revenue payments cannot be represented in the SEDM, it is arguable that the SEDM runs do not fully represent the zonal scenarios as either a cost minimisation or profit maximisation problem. A comparison of the results from these two models can be found in section 7.1.3.

6.3. Discussion

6.3.1. Carbon reduction scenarios

The carbon reduction scenarios have been undertaken as model runs using the SEDM to show the capabilities of the model as a complex, sophisticated tool designed to inform policy decisions. These scenarios explore both implicit and explicit modelling methods representing carbon reduction policies. Carbon targets can be modelled implicitly by use of subsidy payments to low carbon generation and as additional payments based on emissions output to carbon-producing generation. They are also modelled explicitly here as set limits on emissions reduction which cannot be exceeded.

There are some limitations associated with modelling carbon reduction scenarios in this manner. Representing subsidy payments as negative costs by reducing the short run costs of generation and making the model more likely to invest in low carbon generation due to the cost minimisation has not been shown before in the literature and means that the optimisation problem falls somewhere between a cost minimisation and profit maximisation.

Furthermore, the inclusion of explicit emissions targets in the Emissions Limits scenario is an interesting way of exploring the electricity mix that could be possible to meet these targets. However, it does not represent a direct policy mechanism which could be utilised to ensure that emissions limits are not exceeded.

6.3.2. Zonal pricing scenarios

The three scenarios modelled using the SEDM each have their own limitations, as has already been discussed in relation to the two node solver in section 5.4.3. The base case has been modelled as unconstrained to represent wholesale electricity trading within GB. However, as all dispatch occurs without limitation due to the transmission network, the need for redispatch for system balancing is not captured within the model, nor are the costs associated with this. In the two zonal scenarios a transmission constraint is modelled at the Scottish-rGB border, and so generation dispatch occurs taking account of this constraint. However, congestion within these zones is not modelled, and the costs associated with system balancing and redispatch within zones are not included. The Zonal strike price scenario has been modelled using equal top-up payments in both zones to represent a case where different strike prices in Scotland and rGB result in equal total uplift per MWh production because zonal capacity factors (and thus annual energy production and LCOE) were dependent on location of installed wind capacity within the zone, and change based on scenario inputs. This is unlike the two node solver in which it was possible to represent zonal strike prices as zonal levelised costs of wind, as wind in Scotland and in rGB each had a single zonal capacity factor.

In Chapter 5 two cases were found in which the two zone solver did not reach a single solution during the SRMC iteration process. In the results sets explored in this chapter, the SEDM iteration process of input and output zonal SRMCs do converge, to a convergence criteria of no greater than £0.10/MWh difference between iterations in any model year. This convergence is possible because of the additional complexity of the problem and the many additional constraints, as the range of generation technology types and number of demand blocks in the SEDM mean that the SRMC will fall within a large range of figures, instead of the two technology types giving only two options from marginal technology in the two node solver.

6.3.3. SEDM model limitations

There have been various assumptions, simplifications and limitations involved in the SEDM modelling process. Some very basic assumptions include the conversion factors used when representing European carbon prices from generation over interconnectors or converting fuel costs from US dollars per barrel. In these cases the conversion factors of €1.1/£ and $1.6/£ were used based on the exchange rate at the time of the model updates. In addition to this, annual fuel price forecasts and annual carbon price forecasts were input to the model assuming that the sources (publically available documents from DECC and the CCC) would be an accurate forecast. A social discount rate of 6.5% was used, as assumed by AF Mercados during model creation, with technology specific hurdle rates represented as an additional CAPEX figure but not applied to variable costs, as discussed in Section 4.3.4.2. For comparison, DECC and BEIS reports use a discount factor of 10% in their analysis [33], [177].

As with the two zone solver, the SEDM primarily focuses on the direct costs associated with the installation and operation of various types of generation, in the form of CAPEX and OPEX. Indirect costs are not modelled, for example balancing costs, grid costs, market transaction costs and policy implementation costs. Strike prices have been assumed at the levelised cost of energy (LCOE) for each technology type, calculated using input cost data and output generation data from various model runs.

In the SEDM, the dispatch of thermal units is simplified by assuming that each generator has a single operating point on the efficiency curve, and as such variable operating costs are linear. This also means that different emissions levels at different generator efficiencies are not captured. Emissions have an impact on the investment in generation in the model, as carbon pricing is an element of the cost minimisation. Availability is modelled using average availability factors, and so the model does not distinguish between scheduled and forced outages and the different times of year at which they might occur. Hydroelectric generation, particularly with pumped storage, cannot be optimised chronologically or over seasons. However, as GB has only limited amounts of hydroelectric generation (about 4% of capacity) representing this in a more complex way would most likely not greatly impact upon results.

Technology-specific constraints on annual build and generation are used to represent supply-chain capabilities, resources and planning issues. These figures are based on the Carbon Trust practical resource estimates [221] and DECC 2050 Pathways Analysis [222], but have been altered based on results from model runs and experience from the consultants at Mercados. No source has been provided for the model limits on total annual investment, and it has been assumed that this is based on a best-guess assumption.

Annual demand in the model is based on DECC demand predictions from 2014 [182], as discussed in section 4.3.4.1. Annual demand for GB in TWh from 2014-2035 in the SEDM is shown in Figure 49. It can be seen that model demand falls in the first few years of the SEDM simulation, in line with DECC demand projections, and does not rise to 2014 levels again until 2026.

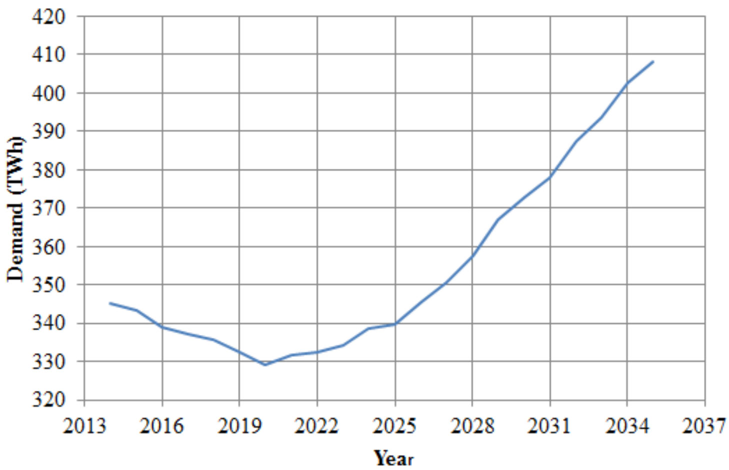


Figure 49 – SEDM GB-wide demand in each year from 2014-2035

Figure 50 shows the installed low carbon capacity from the SEDM results between 2014 and 2020. As model demand reduces up until 2020, new installed capacity is only required in the first seven years of the scenarios to replace some retiring generation. Furthermore, generation built up until 2016 is included in the SEDM as planned generation, and so the model is only required to make investment decisions from 2017-2020. In fact, market splitting does not occur in the SEDM until 2021 in both of the zonal scenarios. It can be seen that all scenarios have identical installed low carbon capacity until 2018, after which there is only a slight difference in installed low carbon capacity between scenarios until 2020. There is less than 1% difference in low carbon installed capacity between the zonal scenarios and the base case scenario in 2020.

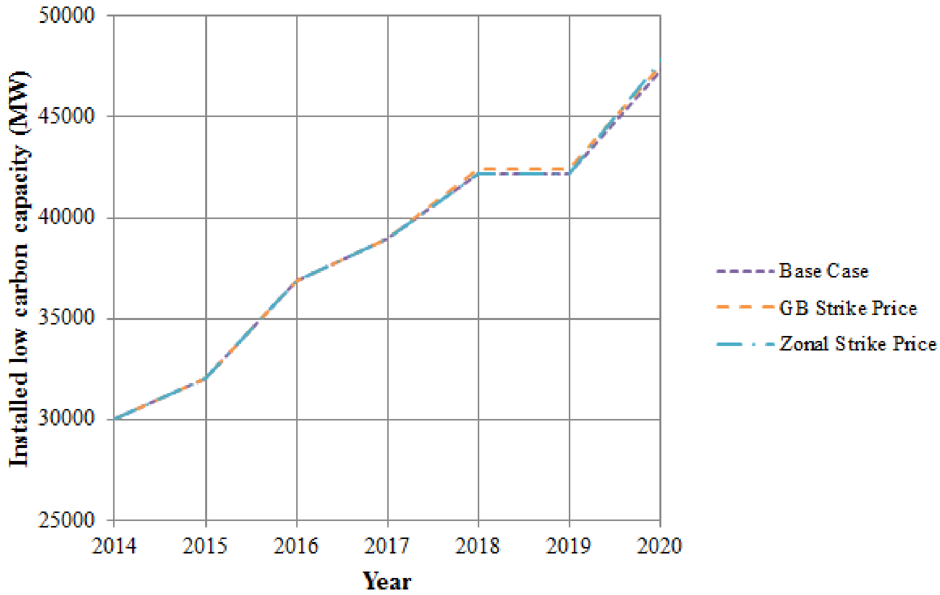


Figure 50 - Installed low carbon capacity in each year for each of the scenarios up until 2020

Demand profile shapes at different nodes are likely to differ slightly, for example the south of England will have a different demand pattern to the north of Scotland due to regional variations in demand for heating or cooling. The model does not capture this, assuming one demand profile for all nodes with different total energy demand at each. Demand profiles are also likely to change in the future with increased penetration of renewables and the increasing electrification of the transportation system. The modelling and projection of future demand profiles is still in its infancy [223] and thus beyond the scope of this work, so the model merely scales a current demand profile into the future. This also fails to take into account the potential move towards more flexible demand in later years of the simulation. This could result in the model underestimating the amount of renewable generation it is able to invest in, meeting a demand-supply matching constraint that is based on a single demand profile for all years and does not account for increasing flexibility associated with electricity demand.

All new renewable generation in the model after 2015 is assumed to be awarded a CfD. This assumption has been made as without such a contract, investment in low carbon generation would not go ahead based on the current input cost data. There is also only a very limited representation of technology learning rates, with cost figures for 2016, 2020 and 2030 input from the 2013 generation costs report [177]. The more recent update to this report in 2016 [33] has shown significantly lower lifetime costs for many technologies, including offshore wind, which were not predicted in the 2013 figures.

The SEDM does not have the capability to include revenue payments and so the only model runs possible are those which only include CfD top-up payments as negative costs. The limitations of this representation of zonal pricing without zonal revenues is discussed in section 7.2.2.

The SEDM assumes perfect competition, installing and dispatching generation which minimises all costs. As such it assumes a central market clearing and dispatch process that does not occur in GB, which mainly relies on bilateral trading and self-dispatch. The model manual assumes that the current GB setup compares reasonably well to perfect competition, with the same investment influences [180]. The forward markets for bilateral trades are impacted by the same factors as the wholesale prices in the long term model, such as fuel and carbon prices, and are dependent on upcoming investments, retirements and demand. There are limitations to investment modelling in this manner when considering a system such as GB. Market power, bilateral trading agreements, government targets, policy instruments and planning procedures all impact on investment in generation, and cannot be represented explicitly in the SEDM. Technology-specific constraints on annual investment and generation are used to represent the capabilities of the supply chain, available resources and planning procedures, but it is impossible to fully predict how these factors could impact on investment and dispatch of generation in the future.

A representation of Transmission Network Use of System (TNUoS) charging is included in the base case SEDM run, but not in the zonal pricing scenarios. This is because SEDM runs which include transmission constraints have the option to invest in new transmission capacity rather than pay TNUoS. For the base case run, TNUoS charges were input at the 2015 values in each zone for every model year. It is arguable that this oversimplifies these charges, as in reality if more intermittent generation with lower load factors was installed in the Scottish regions, the TNUoS charges would increase in these zones. This would potentially have a similar impact as the zonal pricing scenarios, disincentivising investment in intermittent generation in Scotland. As model investment decisions do not impact on TNUoS charges for future model years, their impact on investment is not fully represented in this study.

This work has revealed some general issues with large scale optimal modelling of power systems, reflected in the setup of the SEDM. This includes the issue of meeting computation requirements, such as reasonable simulation times. For example, enabling transmission constraints results in a more realistic dispatch, but also takes a great deal more time to run scenarios than the unconstrained model. A single SEDM run with full transmission constraints between the 14 nodes enabled can take up to four hours, whereas with an unconstrained network run takes 10-15 minutes. When modelling large complex systems there is a trade-off involved with simplifying the simulation problem to reduce the number of decision variables, and developing a model which accurately represents the system.

Another example of the simplification of inputs in SEDM to maintain a reasonable simulation time is the temporal characterization of demand by aggregation of load duration curves and renewable generation availabilities into blocks. Demand is simplified into load blocks and so the modelled demand does not quite represent chronological load. This is illustrated in Figure 51.

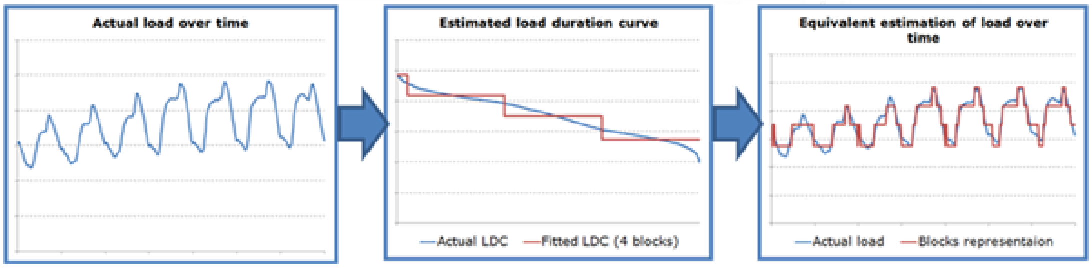


Figure 51 – Comparison of blocked duration curve with load duration curve in representing load over time, from the SEDM design document [180]

Chapter 7.

Discussion and Conclusions

The key premise of this thesis is that introducing zonal pricing to GB could negatively impact upon the ability to meet carbon reduction targets in the most cost-effective way. This is because stochastic resources such as wind generation would not be able to locate in areas with the highest capacity factors, as their optimal locations would be too far away from load centres. This concept has been investigated by the use of two investment optimisation models, a simple two node solver and the more complex Scottish Electricity Dispatch Model, by comparing two zonal scenarios with a base case representing the current GB system. The zonal scenarios represent the case in which CfD auctions still occur to a single GB-wide strike price and the case in which zonal CfD auctions are introduced in Scotland and rGB. This modelling work aims to begin to fill a gap in the literature, as no work has previously been published modelling the interaction between a subsidy framework with contracts for difference and the introduction of zonal pricing. This chapter will summarise the main results, discuss the key differences and similarities between the two models and the advantages and limitations of the modelling methods used in this work, before concluding by discussing the relevance of these results and limitations in relation to the thesis concept.

7.1. Results summary

7.1.1. Two-node solver

The two-node solver results are discussed in full in Chapter 5. Two model set-ups were explored with the two-node solver, running the base case and two zonal scenarios for each. These model set-ups used objective functions representing both minimum cost to society and maximum profit for the developer. The two-node solver results revealed various cases in which the SRMC iteration process did not converge, but instead iterated between two discrete solutions labelled (a) and (b).

The model set-up representing minimum cost to society included CfD subsidy payments as positive terms in the cost-minimisation, to minimise the costs that would be passed on to the consumer. A constraint was included to ensure that the LCF expenditure limit was met, so that renewable generation uptake was appropriately represented in GB. These two node model runs resulted in market splitting in both of the zonal scenarios. It was found that both of the zonal scenarios had a lower installed capacity of wind generation in Scotland, as a greater amount of lower capacity factor wind generation was installed in rGB due to the changes in trading. This did result in a lower overall cost to the consumer and to the producer for the zonal scenarios, and higher total carbon emissions compared with the unconstrained base case.

The model set-up representing maximum profit for the developer included subsidy payments and a representation of generator revenues as negative cost terms in the cost minimisation, reducing the variable cost of wind technology due to the top-up payments and wholesale market revenues. These two node model runs also resulted in market splitting in both of the zonal scenarios. It was again found that the installed capacity of wind in Scotland was lower and the installed capacity of wind in rGB was higher in the zonal scenarios than in the base case scenario. As such, the zonal scenarios were more expensive to the producer, but less than or equal in cost to the consumer compared with the base case scenario. The zonal scenarios also produced higher carbon emissions than the base case scenario.

The sensitivity analyses undertaken with the two node solver explored the inclusion of an additional 20% headroom in the LCF budget and the inclusion of additional transfer capacity due to the Western HVDC Link to the set of model runs maximising profit to the developer. These both produced results sets in which neither of the zonal scenarios converged during the iteration process for input and output SRMCs. Results showed that increasing the LCF budget led to additional installed wind generation in Scotland for the base case and in rGB for the zonal scenarios, with the zonal scenarios still installing less wind in Scotland than the base case. Costs to the consumer and the producer are of course higher with a higher LCF budget due to additional spend on subsidies and new installed capacity respectively. The total emissions produced in the scenario with a higher LCF budget are lower. Increasing transfer capacity due to the Western HVDC Link allows for more wind to be built in Scotland in most of the scenarios. This result is supported by multiple studies in the literature which analyse the benefit of additional transmission capacity in increasing the amount of installed wind capacity which is able to be utilised [137], [168]. The scenario runs with the additional transmission capacity were higher in cost or equal to the scenarios without the additional transmission capacity in terms of both cost to the consumer and cost to the producer, and had lower carbon emissions. This also does not account for the cost of increasing the transmission capacity. The zonal scenarios with additional transmission capacity also still install less wind in Scotland and produce comparable or greater carbon emissions compared with the base case.

It was concluded that the difference in objective function set-up impacts greatly on the final results, with very different installed capacity results produced for either type of objective function. This is supported in the literature by Cerda and del Rio, who by means of mathematical modelling show that functions minimising cost to the consumer do not necessarily minimise cost to the generator and vice versa [217]. However, in each of the two node solver model set-ups and sensitivities, wind generation was installed to a lesser extent in Scotland in the zonal scenarios compared with the base case scenario. For the scenarios with a cost minimisation objective function, the cost to the producer and the consumer were lower for the zonal scenarios than for the base case, while the emissions produced were higher. For the scenarios with a profit maximisation objective function, the base case was more expensive in terms of total costs to the consumer than the zonal scenarios, but consistently produced equivalent or lower costs to the producer and lower carbon emissions than the zonal scenarios.

7.1.2. SEDM

The SEDM results are discussed in full in Chapter 6. The SEDM did not have the capacity to include revenue payments, and so results are not directly comparable to the two-node solver results. The limitations of this approach have been discussed in detail in section 6.3.3. However, SEDM can still be used to model the difference in subsidy payments caused by different zonal prices, and the impact that this has on the long term investment in generation capacity, and therefore still produces interesting and relevant results for this work. The SEDM simulations all converged to a difference of no more than £0.10 between iterations due to the additional temporal and spatial complexity involved with the model set up.

The SEDM emissions reduction scenarios introduced three methods for modelling carbon reduction policy - subsidies to renewable generation, carbon pricing to carbon producing generation and explicit emissions limits. Results showed that within the SEDM setup, renewable subsidies and carbon pricing were not sufficient to meet CCC emissions targets in the long term. Furthermore, carbon emissions were found to be 95.6% greater in the scenario only modelling subsidies to renewable generation compared with the scenario with explicit emissions limits. This result is comparable to various studies in the literature which show that carbon pricing and subsidies in their current form are not sufficient to meet long term carbon reduction targets [139], [172], [224], [225].

The zonal scenarios modelled in the two-node solver were also represented in the SEDM, although as the SEDM does not include the ability to model revenue payments the zonal scenarios were represented by the difference in CfD top-up payments. Overall, the amount of installed wind capacity in Scotland was less in the zonal scenarios compared with the base case scenario and the cost to the consumer was very slightly less in the zonal scenarios. This results in GB strike price scenario having 9.13% lower wind generation (in MWh) in Scotland compared with the base case scenario, and the zonal strike price scenario having 8.38% lower wind generation in Scotland. There is also a consistently lower installed capacity of low carbon generation in the zonal scenarios compared with the base case, leading to a greater amount of energy production from carbon producing generation and thus greater carbon emissions from these scenarios.

7.1.3. Results comparison

A direct numerical comparison of installed capacity, generation and spend between the SEDM and two node solver results is not a useful exercise, as the two models have different input conditions, demand profiles and constraints. However, the overall results showed some similarities, which are useful to discuss in the context of the existing academic literature.

The results for both models found that market splitting occurred in all of the zonal scenarios, even in the case of additional transfer capacity due to the Western HVDC Link, included as a sensitivity analysis in the two-node solver and in all scenarios in the SEDM runs. In every case this market splitting resulted in lower zonal prices in the Scottish zone compared with the rGB zone, and thus higher top-up payments to generators in Scotland for the GB strike price scenario. This leads to all of the model results installing less generation in Scotland in the zonal scenarios compared with the base case.

This work compliments a range of studies in the literature focusing on the impact of using zonal pricing for congestion management within the single European energy market. Italy is a particularly interesting case study due to its historically high wholesale electricity prices and instances of high congestion before market coupling was introduced. Pellini used the optimal dispatch model ELFO++ to represent market coupling in central-south Europe, finding that higher price regions such as Italy could greatly benefit through increased access to low cost generation, resulting in higher social welfare [219].

Even more relevant to this work is the case of Germany. It has been suggested that Germany could also be split into two price zones due to large amounts of wind generation causing congestion between the north and the South. This has obvious parallels with GB and with this work. However, there is also a key difference between modelling multiple price zones within Germany and GB, as Germany is not an island it is much more interconnected with neighbouring countries. Plancke et al use a cost minimisation dispatch model to analyse the impact of splitting Germany into two price zones, finding that the split reduces instances of redispatch actions but increase instances of loop flows occurring in neighbouring regions [14]. Plancke et al do not comment on the impact of introducing two price zones on market signals to low carbon generation, however.

It can be concluded that while there is a great deal of discussion and literature on the optimal bidding zone configuration in Europe in terms of minimising redispatch actions [21]–[24], there is very little on the impact of introducing new price zones in terms of most effectively achieving long term carbon reduction targets. As these targets continue to get more ambitious it should be ensured that electricity market design in general and market based methods for congestion management in particular do not negatively impact on efficient carbon reduction in energy systems.

It can thus be seen that this work provides a significant additional contribution to the literature. No other studies have yet been produced which model the impacts of an additional price zone within GB or any other region on investment in low carbon generation, or which model the potential interaction between introducing multiple price zones within a region and a subsidy framework incorporating contracts for difference.

7.2. Discussion

In addition to the key results produced in this work, a discussion of the modelling methods is a useful output. This section compares the two models used to obtain these results, and goes on to discuss the modelling methods used throughout this work.

7.2.1. Comparison between the SEDM and the two node solver

The mathematical set-up of both the SEDM and the two-node solver have been detailed in Chapter 4. When comparing the two, it is important to note their purpose. The SEDM has been professionally developed by the consultancy AF Mercados for the Scottish Government, with the purpose of better understanding the impacts of policy decisions such as carbon pricing, carbon and renewables targets and the CfD mechanism on the long term investment of generation. The SEDM has four demand blocks (and twelve wind generation blocks) per season over the twenty-two year time horizon, makes investment decisions between twenty-six technology types over fourteen model nodes and has multiple constraints for each year, representing policy, supply chain and technical limitations. These include constraints on annual investment for each technology type and overall spend and annual generation for technologies such as coal and biomass to represent carbon reduction policy and the supply chain for biomass fuel. This complex, sophisticated model has been adapted for the purposes of this work in many ways, including a representation of CfD strike prices as technology-specific levelised costs calculated using model inputs and outputs and a representation of the appropriate payments to generators due to the zonal pricing scenarios. As such, the results presented here do not reflect those output by the version of SEDM used currently at the Scottish Government, which has itself been updated since this work was completed.

The two node solver has been developed for the purpose of this work, to illustrate the impacts that zonal pricing scenarios could have on the investment of generation where model decisions are not impacted on by as many constraints as the SEDM. By contrast, this simpler modelling framework has two nodes, two demand blocks per year over six model years, makes investment decisions based on two technology types and has significantly fewer constraints, which are only used to represent supply-demand matching, transmission net transfer capacity and the LCF. As such, the two node solver has been set up with a much simpler approach, with the focus on illustrating the problem rather than representing the GB power system in a detailed, accurate manner. It has been set up with demand increasing linearly each year, with the choice of only two types of generation and with a few simple constraints so it is clear in every model year why a certain type of generation has been installed at a particular node. The installed capacity mix for the first year of the model time horizon is not fixed, as it is in the SEDM, but instead the model can decide the capacity it needs to install based on the constraints to be met. As such, the two node solver can be described as a greenfield model, whereas the SEDM is a brownfield model. This has resulted in model outputs which vary more significantly between scenarios than the SEDM outputs, to illustrate the potential impacts of zonal pricing further. Due to this, results from the two node solver are best described using a qualitative comparison between scenarios rather than comparing the quantitative outputs to the current GB system.

An example of the additional complexity involved with the SEDM set-up is the modelling of wind generation. Generator availability due to wind resource is modelled in much greater detail in the SEDM compared with the two node solver, with low, medium and high wind resource blocks for every demand block, to represent that low wind resource can occur at any time. In addition to this, the spatial complexity of the wind resource is represented by thirty-nine wind site data sets. Due to its complexity, the SEDM takes up to two hours to run a single iteration for the zonal scenarios where the transmission constraint at the Scotland-rGB border is included. The two zone solver by comparison takes seconds, as the model is much simpler and involves the computation of fewer decision variables. The two node solver does not take account of the intermittent nature of wind generation, however, as generator availability is modelled by capacity factors alone.

Another key difference between the two models is the modelling time horizon. The SEDM runs for twenty-two years from 2014-2035 whereas the two node solver runs for six years from 2015-2020. From the results in Chapters 5 and 6 it can be seen that the levelised cost of onshore wind (used to represent the strike price) differs between £84.75/MWh in the SEDM and £87.01-£104.40/MWh in the two node solver. This is due to the levelised cost calculation only taking into account the model lifetime rather than the generator lifetime with respect to the O&M costs and energy delivery. The capital costs are discounted to account for the amortization period, and the fixed and variable O&M costs only apply for the model lifetime. Table 19 shows the two node solver, SEDM, DECC and BEIS levelised cost figures for CCGT and offshore wind. It can be seen that the two node solver CCGT levelised cost is much lower than the other values stated, as the two node solver only runs for a six year timeframe and thus the model lifetime cost does not account for the additional years of fixed and variable costs. Ideally, to fully represent the lifetime costs associated with the CCGT generation, it would be modelled for the period of the full generator lifetime. However, it is unlikely that this will have impacted greatly on the results of this study, as they use the short run marginal costs of generation to represent zonal wholesale prices and the short run costs of both CCGT and wind are consistent between the two models.

Table 19 – Levelised costs for CCGT and wind generation in the two-zone solver, SEDM, DECCs generation costs report [177] and BEIS generation costs report [33]

£/MWh	two-zone solver	SEDM	DECC 2013	BEIS 2016
CCGT	46.21	93.08	75.00	66.00
Onshore Wind	87.01-104.40	84.75	104.00	63.00

The costs used as model inputs for CAPEX and OPEX were based on available data in 2013. However, as Table 19 shows since this time these costs have changed considerably. Based on the BEIS 2016 data the apparent gap between the levelised costs of energy of wind and CCGTs has reduced greatly and, depending on what is assumed for the price of gas, could perhaps be reversed. Indeed, the 2017 CfD auction results shown in section 2.1.3.1 have 2.33GW of offshore wind projects winning a CfD at £57.5/MWh, suggesting that the levelised cost of onshore wind could be lower still. This is in fact lower than the SEDM average marginal price in the base case run, so to try and model this as a strike price could result in the generator having to pay back considerably more than it receives in subsidy. Further to this in 2019, following the conclusion of this research, the third CfD auction round saw strike prices for offshore wind and remote island onshore wind projects falling even further to as low as £39.65/MWh. This is lower than the average wholesale market price in GB, and the fact that projects submitted bids so low illustrates the value of mitigating price risk to project developers.

The results for the two models also show different average short-run marginal costs, with the two node solver output zonal average SRMCs at £2.21/MWh for the short run marginal cost of wind generation and £47.82/MWh for the short run cost of CCGT. The SEDM output zonal average SRMCs ranged from £56.02/MWh to £68.00/MWh. For comparison Ofgem's wholesale market indicators show monthly average day-ahead baseload contract prices ranging from £33.85-67.54/MWh over the period of 2010-2016 [39]. Prices vary between the two models as the marginal generator in the two node solver peak block is always CCGT, whereas in the SEDM the marginal generator is OCGT or Oil in the peak blocks, which have higher short-run costs. This illustrates the impact of using a more complex model, which better represents the wider range of generation sources within GB, compared with a more simplistic model which only represents two forms of generation. The representation of short run costs is vital in this analysis to calculate the different zonal prices, CfD top-up payments and the overall impact to the LCF. The simplifications associated with the two node solver are the main reason that these results have been discussed qualitatively rather than quantitatively in this work.

Perfect competition is assumed in the modelling work completed here. That is, the system marginal price is assumed to be sufficient to represent the wholesale price of electricity in the CfD top-up payment calculations. Generators are assumed to bid in their short run marginal costs and the marginal price is calculated as the highest SRMC required to meet demand in each model demand block. It is true that if there were no grid losses, network congestion did not occur and there was no market power, a centralised market based on the marginal price would yield the true electricity price, the optimal dispatch and the optimal investment incentives. However, the largely bilateral GB wholesale market is not perfectly competitive, and network congestion often results in the process of balancing and redispatch post gate closure. Assuming perfect competition with generators gaining the system marginal price of the highest short-run marginal costs required to meet demand means that generation without a subsidy does not recover its capital costs, as other revenue streams to carbon producing generation such as capacity contracts, capacity market revenues and participation in balancing and ancillary services markets are not modelled. Table 20 shows the cost and revenue streams of onshore wind and CCGT generators per MWh of generation produced from both the two node solver and the SEDM. It can be seen that in both models the total average revenue is less than the levelised cost of generation, meaning that CCGT generation in either model does not cover the costs of generation from revenue payments of the average system marginal price.

Table 20 – Cost and revenue streams for onshore wind and CCGT in the two node solver and SEDM base cases

(£/MWh)	Levelised cost	Average system marginal price	average top-up payment	Total average revenue	Levelised cost minus average revenue
two node solver					
onshore wind	104.40	45.99	58.41	104.40	0.00
CCGT	46.21	45.99	0.00	45.99	0.22
SEDM					
onshore wind	84.75	65.11	19.64	84.75	0.00
CCGT	93.08	65.11	0.00	65.11	27.97

In the SEDM the LCF subsidy spend was not constrained, as the limited choices in investment in capacity up until 2020 mean that the current budget is not exceeded. In the SEDM this figure also includes ROCs and small scale FiT payments to existing generation. The subsidy spend from 2014-2020 in all three scenarios is approximately £30billion. The LCF budget to 2020 is almost £38billion in 2014 prices, and so it has not been exceeded in these results. The two node solver uses the LCF as an equality constraint for the top-up spend to ensure a level of investment in low carbon generation representing the current GB generation mix.

There are various challenges involved with the interpretation of results from such a large, complex model as the SEDM, compared with the relatively simple framework of the two node solver. The results produced are highly sensitive to the enabled constraints and other inputs such as demand forecast, fuel prices and carbon prices. It is important to consider which results are the most appropriate to display when comparing different scenarios and sets of model results. For example, using the installed capacity of a particular year of the model runs for results comparison does not give an indication of the generation capability of a particular technology throughout the model lifetime. Figure 52 shows the new build installed capacity in each year for the SEDM base case. It can be seen that in some years large chunks of capacity are installed and in some years very little or no capacity is installed. The amount of new build installed capacity in any model year is sensitive to the changes in demand due to the predicted demand profile and to retirements in the generation fleet. This graph also illustrates two years in which the constraints limiting total annual new build installed capacity are met, 2030 and 2031. This is similar for the two zone solver results sets, in which the minimum cost to society scenarios install wind generation in every year until the LCF budget constraint has been met, resulting in a much higher final installed capacity of wind in the last year of the model time horizon than the maximum profit to developers scenarios, which tend to install wind as a large chunk of capacity in the first year of the model, so that the largest amount of wind generation can be dispatched over the model time horizon to gain top-up and revenue payments. As such, the total energy production over the model lifetime can be a more interesting result for scenario comparison than the installed capacity in a particular model year.

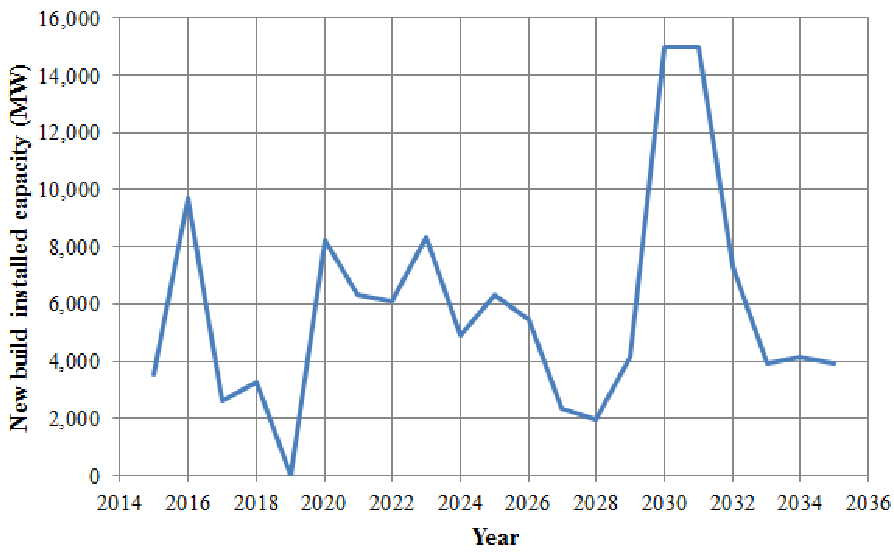


Figure 52 – New build installed capacity in every year of the SEDM base case

Electricity markets have been traditionally based on the trade of dispatchable, predictable thermal generation with low capital costs and high operational costs. Renewable generation is less able to respond to locational signals than traditional dispatachable thermal generation, as its energy production is heavily reliant on geography and renewable resource. Wind generation in particular is less predictable, often best sited in geographically disperse locations and has high investment costs and very low operational costs. As such, wind generation has different requirements from the market than conventional generation, being supply-driven rather than demand-driven. Redispatch and balancing were not explicitly modelled in this work, but there will also be instances where wind is used for redispatch (or bids in at less than the total possible output to hedge for non-delivery penalties and takes the system sell price), and if we are looking for the lowest cost solution with the most installed wind capacity then introducing zonal pricing could heavily impact on this.

In GB some locational signals are already provided to generation from Transmission Network Use of System charges, which have not been modelled in the zonal scenarios explored in this work. When developing these charging arrangements, the impacts of locational signals on low carbon generation was discussed in an academic review of the transmission charging arrangements for Ofgem by the University of Exeter, highlighting the importance of wind generation in meeting 2020 targets:

"*it is clear that wind is the only renewable technology that can currently be deployed to scale and is therefore crucial in terms of delivering the UK's immediate renewable and low carbon objectives. Onshore wind will be required to make a significant contribution to the 2020 target and it is therefore particularly important that strong locational signals contained within use of system charges do not close down otherwise viable onshore siting options"* p9 [226]

Appropriate investment in transmission capacity is also key in ensuring the optimum utilisation of low carbon generation. Market splitting should not only be a signal to generation investors on where to locate new capacity, but also to network owners on where reinforcements might be justified. Such network investment should not be assumed to remove all network congestion at all times but to reduce it up to the point at which the marginal cost of additional transmission equals the marginal benefit in terms of reduced cost of electricity.

7.2.2. Modelling methods

Chapter 4 described a number of different models used to optimise investment and dispatch of electricity generation in the long term. The models featured were chosen to highlight the range of modelling methodologies currently used by researchers and policy makers to investigate the impact of market signals on investment in generation. As the premise of this thesis was to investigate the impact of zonal price signals within GB on investment in generation, the models chosen for this work primarily optimised long term investment decisions within GB. The SEDM was chosen as a complex, professionally developed model which represented Scottish generation, demand and transmission with more detailed spatial complexity than the rest of GB. The SEDM was specially developed for the Scottish

Government, to allow policy makers to better understand the impacts of policy decisions on investment in generation. As this work focused on the impact of introducing zonal pricing to GB on investment decisions in Scotland and aimed to produce results of relevance to policy makers, the SEDM was a logical choice of tool to use.

However, a key limitation of using SEDM for this work was that the model set-up did not enable the user to investigate profit maximisation objective functions and include a representation of market revenues. CfD top-up payments could be represented as negative 'payments' within the cost minimisation but it was not possible to extend this to also include zonal revenues as negative terms. It is arguable that to fully represent the impacts due to zonal pricing, zonal market revenues must be included in the objective function. To fail to represent this income which is proportional to energy output and which differs depending on the location of the generator results in a distortion between the fixed and variable costs impacting on the generators revenue stream. In the SEDM runs, revenues to generators are represented only by the CfD top-up payments. In the Zonal strike price scenario, wind generators located in Scotland and in rGB gain equal revenues per MWh of output in every model year, and Scottish wind generation looks comparatively cheaper to the model in the long term due to its higher capacity factor. In reality, due to market splitting, in a zonal pricing scenario generators in Scotland would gain lower market revenues than generators in rGB and so this case does not fully represent the impacts of zonal pricing on investment in generation.

As such, although the SEDM results are a useful way of exploring the impact of zonal pricing on top-up payments to generators and the resultant signals to investment in generation, a model including a representation of zonal revenues would allow for a fuller representation of price signals to investors due to zonal pricing.

The two node solver was created especially for this work to further illustrate the impact of zonal pricing within a simple framework, where investment decisions were made between two technologies: CCGT and wind. In the two node solver, both top-up payments and revenue payments can be included in the objective function, with the zonal average SRMC in each year representing wholesale market revenues. In the zonal strike price scenario profit maximisation results considerably more low carbon generation capacity was invested in rGB, where zonal market revenues were higher. This change in results compared with the SEDM zonal strike price scenario reflects the importance of properly representing the correct revenues to developers in zonal pricing scenarios.

A key limitation of the two node solver was its inability to converge in the iterative process which calculates top-up payments as inputs based on a previous runs SRMC outputs. This meant that several sets of results were produced for many scenarios run. The two node solver results are of use for this work, however, as they consistently support the thesis premise that introducing zonal pricing would result in less wind being installed in the Scottish zone, despite having higher wind resource.

It can be concluded that although these two models produced interesting results which supported the thesis premise, in future to model the impacts of introducing zonal pricing within GB then ideally a suitably complex model of the GB system should be used which can also include a representation of revenue payments, if profit maximisation objective functions are to be explored.

It is difficult to judge how the modelling methods shown in this work compare to those undertaken by policy makers, for example when conducting a bidding zones review, as these methods are often not shared publically in detail. However, the commercial tools described in this work such as Ordena plus, BID3 and Plexos all have a similar format, minimising the cost of generation given certain constraints used to represent power system operation. E. Cerda and P. del Rio discuss that the definition of 'cost effectiveness' is described in multiple ways across the available literature: as a minimisation of the cost of low carbon generation, as a minimisation of the cost of support to generation and as a minimisation of consumer costs [136]. It is argued that various styles of modelling are used by different policy makers to reach the most 'cost effective' solution, but that modelling results minimising cost to the consumer do not necessarily also result in minimising cost to the generator, and vice versa [217]. This work models investment in generation with regards to both minimising cost to society and maximising profit to the developer and the results also show very different solutions in several scenarios, as discussed in section 5.4.1.

7.3. Further work

As has been highlighted in section 7.2.2, for further investigation as to the impacts of zonal pricing within an area such as GB with a CfD subsidy mechanism, it would be beneficial to create or use a more complex model which allows for the exploration of all scenarios with a representation of zonal market revenues, represents the wind resource and demand profiles with the appropriate temporal and spatial detail and also appropriately represents intra-zonal redispatch and the associated costs. The two node solver described in this work was created to illustrate the potential impacts of introducing zonal pricing to GB, and increasing the temporal and spatial complexity would more accurately represent the GB power system whilst also resulting in convergence between output SRMCs and input reference prices.

This work has focused on the use of subsidies in the form of CfD top-up payments as a policy instrument to meet low carbon targets. It is also arguable that a sufficiently high carbon price would incentivise low carbon generation and result in no need for additional subsidies, as carbon producing generation would be comparatively more expensive to install and run. For example, in the two zone solver the carbon cost necessary to incentivise onshore wind generation over CCGT with no additional subsidies is £28.83/MWh or £63.92/tonneCO_2. This is over three times the current carbon price floor figure of £18/tCO_2. Further work could explore the impacts of higher carbon pricing on the future power system, and the sensitivity of zonal pricing results to the carbon price.

One of the things this kind of idealised modelling has not explored is the uncertainty associated with model inputs. In the modelling it is assumed that CAPEX and OPEX costs are known and that investors will invest even if they only gain the SRMC and do not completely cover their long term costs. In practice, future costs are somewhat unknown, presenting risk in terms of how a strike price is set and in what average wholesale prices will be. Further work could explore the sensitivity of the modelling results to these inputs.

Additionally, the scope of this work did not include the development of new interconnectors between GB and Europe, although many are currently in planning. Investigating the impacts of additional interconnection on the zonal pricing results, for example the North Sea Link between Norway and Blyth in the North of England, would have been an interesting additional sensitivity analysis. Additional development in the transmission system was shown to reduce emissions without impacting very much on the total costs to the consumer and producer in section 5.3.2. In the literature Fursch et al used the long term investment model DIMENSION to conclude that improving interconnection capacity within Europe would allow the utilisation of the most efficient renewable generation sites and result in cost savings of €57 billion by 2050 [157].

7.4. Conclusions

This thesis has explored the concept that the introduction of zonal pricing could occur within GB due to the single European Electricity Market stipulation for regular bidding zone reviews and the known transmission constraint at the Scotland-rGB border. It was postulated that this could result in additional locational signals to generation which could disincentivise wind generation from installing in locations with superior wind resource. Modelling work has shown consistently less installed wind capacity in Scotland in scenarios representing zonal pricing compared with scenarios representing the current GB system, and has thus backed up the thesis premise. While zonal pricing could improve system efficiency in the short term and lower the requirement for redispatch, in the long term it could negatively impact on the investment of low carbon generation in locations with the best renewable resource, which would be the most cost-effective method of meeting carbon reduction targets.

This work has aimed to begin to fill several gaps found in the literature as no modelling results have been published which represent zonal pricing within GB or which explore the impacts of multiple price zones on a subsidy framework including a contract for difference. The modelling methods have included representing a range of objective functions, which has been shown to significantly affect the zonal results. Cases have also been revealed in which the SRMC iteration process did not converge for the two zone solver, highlighting the potential issues involved with modelling a subsidy framework like the CfD mechanism within multiple price zones.

To summarise the key conclusions and recommendations from this work:

1. Introducing multiple price zones to GB could negatively impact on investment in wind power in areas of highest resource. Modelling results found that wind generation was consistently installed to a lesser degree in Scotland when included as a separate price zone to the rest of GB, despite the higher resource availability in the Scottish zone. This resulted in higher carbon emissions in the zonal scenario results compared with the representation of GB as a single price zone. It is recommended that policy makers and system planners considering the introduction of multiple price zones within country borders consider the potential impact that this could have on meeting long term carbon reduction targets.

2. Model objective functions have a significant impact on output results. This work has shown that cost minimisation and profit maximisation objective functions produce very different outputs in terms of installed capacity and dispatch. It is important to be aware of this when deciding on a modelling methodology and when analysing modelling results. Modelling investment in power systems is most often done using a cost minimisation objective function, but this may not always be the most realistic representation of investment signals in a competitive market. To represent zonal pricing fully it is arguable that zonal revenues have to be included in the optimisation. It is recommended that modellers clearly state the limitations of their modelling methodologies in representing real power systems and markets when using modelling results to influence and impact on policy decisions.

3. A suitably complex modelling framework is required to model zonal pricing within GB. Representing zonal pricing in a region which utilises a subsidy framework with contracts for difference can result in cases where the iterative process of calculating top-up payment inputs from output SRMCs does not converge to a single solution. This was observed particularly in the simplified two node solver model in this work. As such, the use of more complex modelling tools which represent the full range of generation technologies present in the power system is recommended for any further work modelling zonal pricing within GB.

Point 1 is of most relevance to policy makers. Modelling results have shown that zonal pricing decreased the amount of installed wind capacity in Scotland and increased the carbon emissions produced. Introducing zonal pricing also often reduced the total cost to the consumer due to the comparative price of wind and CCGT technologies within these models. This suggests that higher market efficiency could potentially come at the cost of higher carbon emissions, and policy makers should be aware of how interlinked these two metrics can be when making policy decisions. This point is not just relevant to the GB system, but also to the rest of Europe and beyond to any system utilising zonal pricing for congestion management or considering the introduction of new price zones. The fact that countries such as Germany are also considering internal market splitting to ease congestion due to high penetration of wind power shows that this work is relevant outside of GB.

Points 2 and 3 are most relevant to modellers, be they academic researchers or those specifically undertaking power system modelling to inform policy. Although discussed in terms of modelling GB, these results also apply to any system introducing multiple price zones, and especially if the price zone configuration has an impact on subsidy payments to generation. Point 2 is also of significant relevance to policy makers and applies globally in terms of how investment model outputs impact on policy decisions. The sensitivity of the results to the set-up of the objective function is something which is important to keep in mind when using such models to represent real power systems and markets.

There is currently no information about the continuation of the CfD scheme or funding under the LCF in future years. However, this work also has some more general conclusions about the introduction of zonal pricing in an area where the highest renewable resource is located in a separate zone to the bulk of the load. If carbon reduction and renewables targets are to be met as a priority, investment in low carbon generation should be encouraged. This work has shown that introducing a separate zone to an area with high wind resource and high renewable development results in a lower zonal price when congestion is present, and therefore a lower average zonal price will occur in this region. Renewable generation can bid in to markets at lower prices, as it has lower short run costs than thermal generation, but requires the market to clear at a price that allows it to meet its long term investment costs. Renewable generation would thus be disincentivised from building in zones with lower average zonal prices, even though this zone might have a higher renewable resource and result in a higher capacity factor for the generator. Modelling results showed consistently less wind generation installed in the Scottish zone in the zonal scenarios compared with a base case representing the current GB system. If the overall goal is to meet carbon reduction and renewables targets in the most efficient manner, incentivising generation to build in areas where they can produce at a higher capacity factor is essential, as generation in these areas will have lower levelised costs.

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