The Electricity Generation Infrastructure Transition to 2050: A Technical and Economic Assessment of the United Kingdom Energy Policy

By

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Declarations

The candidate confirms that the work submitted is his own and that appropriate credit has been given where reference has been made to the work of others.

Research outputs

Journal publications

The International Journal of Environmental Sustainability: The Impact of the ‘Shale Gas Revolution’ on the United Kingdom Electricity Generation Outlook

Energy Journal: Developing an optimal electricity generation mix for the UK 2050 future

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Abstract

The threat of dangerous climate impacting on, economies and communities require urgent collective action to reduce anthropogenic greenhouse gases mainly from energy production and use. The UK energy policy has a strong focus on energy security and climate change with an emphasis to accelerate a transition from a fossil fuel to low-carbon based electricity supply system. The development of a low-carbon electricity supply system faces a multiplicity of challenges ranging from policy instability and capital investment. At the backdrop of these complex transitional challenges, this research tracks the evolution of the UK electricity sector to a low-carbon 2050 future. It examines the dynamics affecting the electricity generation system as it adopts and adapts to a regime of domestically engineered low-carbon policies designed to develop a near carbon neutral electricity supply infrastructure by 2050.

This thesis explores the resilience of the UK electricity generation infrastructure as it is exposed to security of supply risks particularly at a time when the system is threatened by potential capacity shortfalls arising from the eminent closure of aging nuclear and coal power plants, with the latter facing total demise in the wake of the crippling European pollution regulations targeting large combustion fossil fuel plants. The large scale deployment of variable renewable energy technologies for the electricity generation sector has a potential to impact on the security of supply.

This research uses the 'Energy Optimisation Calculator' (EOC), a quantitative approach to develop a least-cost and pollution electricity generation portfolio for the UK 2050 future, taking into account the technological, investment, and environmental constraints that characterise an energy system under transition. The flexibility of the model adopted allows for the dynamics that affect the electricity generation sector to be analysed in an integrative manner, providing results that shed insight into the projected outlook of the electricity generation sector as it decarbonises. The model develops different energy scenarios to reflect on the potential pathways the energy supply system could follow to achieve the energy policy objectives. The results generated from this thesis provide an up to date, focused and integrated perspective on how the electricity system could potentially evolve as it transitions towards a low-carbon future

Abbreviations

APERC	Asian Pacific Energy Research Centre
CCC	Committee on Climate Change
CCGT	Combined Cycle Gas Turbine
CCL	Climate Change Levy
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
COP21	21^{st} Conference Of Parties
CPF	Carbon Price Floor
DECC	Department of Energy & Climate Change
DUKES	Digest of the United Kingdom Energy Statistics
EIA	Energy Information Agency
ELV	Emission Limit Values
EMR	Electricity Market Reform
EOC	Energy Optimisation Calculator
EPR	European Pressurised Reactor
EPS	Emissions Performance Standard
ESME	Energy System Modelling Environment
ETI	Energy Technologies Institute
EU ETS	European Union Emission Trading Scheme
EU	European Union
FESA	Future energy scenario assessment
FID	Financial Investment Decision
FOAK	First-Of-A-Kind

GEA	Global Energy Assessment
GHG	Greenhouse Gas Emissions
IEA	International Energy Agency
IED	Industrial Emissions Directive
IPCC	Intergovernmental Panel on Climate Change
LCOE	Levelised Cost Of Electricity
LCPD	Large Combustion Plant Directive
LCS	Low-Carbon Scenario
LMS	Low Mitigation Scenario
MARKAL	MARKet Allocation
MERRA	Modern Era Retrospective-analysis for Research and Application
MLP	Multi-Level Perspective
NOAK	Nth-Of-A-Kind
NPS	National Policy Statement
OECD	Organisation for Economic Co-operation and Development
PV	Photovoltaics
RO	Renewable Obligation
SCR	Selective Catalytic Reduction
SMR	Small Modular Reactors
SNCR	Selective Non-Catalytic Reduction
TCF	Trillion Cubic Feet
UKERC	UK Energy Research Centre
UK	United Kingdom
WT	Wind Turbine

Nomenclature

Symbol

A	turbine swept area (m^2)
C_f	capacity factor
Cp	rotor efficiency
e	exponential
E	electricity generation
E_0	energy output of wind turbine
F(*v*)	wind distribution from Weibull distribution function
h	height
i	number of non-wind speed
I	capital investment (£)
n	lifetime of a power plant (years)
N_d	number of working days of wind turbine
N_h	number of hours in a day
P_A	wind power density
P_{av}	average electrical output
P_r	electrical power output at rated capacity
P_v	electrical output
r	discount rate (%)
t	time
v	wind velocity
v_i	wind speed in time stage
TOM	Total operation and maintenance

Greek Symbols

$\boldsymbol{\eta}$	estimated efficiency of wind turbine
ρ	constant air density (kg/m^3)

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Chapter 1 Introduction

1.1 Climate Change and the global energy economies

Global energy production and use is estimated to have contributed about two-thirds of the world's annual greenhouse gas emissions (IEA, 2015). There is worldwide consensus that climate change is a reality and threat to human civilisation, and thus it is fundamental that international frameworks are developed and agreed to tackle greenhouse gas emissions from industrial activities. The agreement reached at the 21st Conference of the Parties (COP21) in Paris, pledging to keep the rise in average temperatures below 2 ^{o}C (UNFCCC, 2015) relative to pre-industrial levels is another commitment by the international community to tackle the threat of the human induced climate change. The decarbonisation of energy economies, which to date, remain heavily dependent on fossil fuel resources is central to the achievement of the emission reduction milestone agreed at the COP21.

Climate change mitigation is at the heart of the European Union (EU) and UK energy policy frameworks. In order to align the energy policies with the objective of limiting global temperature rise to 2 ^{o}C to pre-industrial levels, the EU and the UK government have made commitments to reduce their greenhouse gas emissions in 2050 by 80 % below the 1990 levels (European Council, 2009; HM Government, 2008). In order to guide the UK economy on a cost-effective path to the 2050 emission reduction target, the fifth carbon budget (2028-2032) developed by the Committee on Climate Change (CCC) recommends a 100 gCO_2/kWh grid intensity to be achieved by the UK electricity generation sector (CCC, 2015). The UK's progress in decarbonising all sectors of the economy, particularly the electricity supply sector could significantly play an important role in assisting the EU's Member States to achieve an agreed emission reduction target of at least 40 % by 2030 relative to 1990 levels (Erbach, 2014). The quest to decarbonise the EU, and indeed the UK economies through climate and energy policies is part of the global initiative seeking to combat dangerous climate change. While the climate and energy policy strategies driven by the EU and international forums such as the COP21 are a welcome development towards stabilising global temperatures, the process of decarbonising energy related economies is fraught with deep uncertainty. The evolution of global energy economies to low-carbon and sustainable futures has to overcome financial, technological, political and social acceptance barriers in order for the national, regional and global climate and energy targets to be met. Above all, these climate and energy policy strategies should endeavour to promote security of energy supply in line with the global energy assessment (GEA) which prioritise robustness, sovereignty and resilience of energy systems (GEA, 2012).

1.2 The UK electricity supply infrastructure: Addressing the 'energy trilemma'

The Climate Change Act set a legally binding target of 80 % emission reduction by 2050 against the 1990 levels to be achieved by the UK economy (HM Government, 2008). The Act enacted a system of five-year carbon budgets framed to guide the economy on a cost-effective path to the 2050 emission reduction target. The decarbonisation framework proposed by the Climate Change Act is to be driven by a transition of the electricity generation sector to a low-carbon future. There is strong consensus within industry, policy and academic quarters that the decarbonisation of the electricity supply sector by 2030 is central to the UK achieving the 80 % emission reduction target by 2050 cost-effectively. Faced with the potential difficulties in decarbonising the UK transport, industry and buildings sectors, the energy supply sector is strategically the prime candidate by which this decarbonisation campaign for the entire economy could be advanced.

The repositioning of the electricity supply system on the path to a low-carbon future is a timely development for the UK energy policy. This is mainly because the UK electricity supply needs to date have been extensively sustained by a fossil-fuel powered infrastructure, which is not only threatened by domestic and regional pressures to decarbonise, but is reaching the end of its technical operation life. The majority of the UK coal-fired generation fleet is over forty-five years old having being built in the 1960s and early 1970s. In the absence of a strong and prohibitive domestic and regional regulations to drive coal out of the UK generation mix, the coal generation sector is likely to maintain its position in the electricity system through the 2020s regardless of the age of plants or the cost of upgrades required to meet environmental policy standards. While the future role of coal generation in an electricity supply system supposedly in transition to a low-carbon future remains uncertain, the UK government has proposed a complete phase-out of coal-fired plants by 2025 (DECC, 2015a). Suffice it to say that the impetus to decarbonise the UK power sector through the deployment of low-carbon energy technologies is set to contribute towards achieving carbon emission targets while at the same time alleviating the security of supply threats by filling the capacity deficit created following plant closures.

The erosion of the UK electricity generation capacity is set to intensify in the early 2020s as the existing nuclear electricity generation fleet is set to be retired as it reaches the end of its operational life, as is the case with the coal generation plants. The UK government is fully aware of the urgency required to replace this capacity. To this end, a policy framework has been adopted which could see the development of a fleet of new nuclear energy plant designs and other low-carbon energy technologies to assist in driving down emissions as well as building up the capacity margins following the potential closure of existing old nuclear and coal electricity generation plants. The development and deployment of baseload and low-carbon new nuclear energy plants from now through the 2020s is significantly important if the UK electricity sector is to achieve a level of decarbonisation which is consistent with the fourth and fifth carbon budgetary requirements seeking to achieve a 100 gCO_2/kWh grid intensity by 2030.

The transition of the UK electricity generation sector to a near zero carbon grid intensity 2050 is dependent on the electricity supply sector achieving a decarbonisation status by 2030. The CCC suggested to the UK government that the power sector should reach a 50 or 100 gCO_2/kWh decarbonisation target by 2030 in order to meet the 2050 emission reduction target cost-effectively (CCC, 2014). This radical emission reduction target within the electricity generation sector has to be realised through the rapid deployment of low-carbon energy technologies such as offshore wind, nuclear and fossil fuelled plants fitted with carbon capture and storage (CCS) technology. Modelling assessments from government, industry and the research community have unanimously proved that it is feasible to decarbonise the electricity generation infrastructure by 2030 with the right policies and technologies in place. To this end, the UK government has indicated that a low-carbon technology portfolio of 40-70 GW would need to be deployed through the 2020s in order to decarbonise the electricity supply sector while ensuring the security of energy supply to the UK economy (HM Government, 2011). The accelerated development and deployment of low-carbon energy technologies from 2014 through to 2030 was estimated to require a capital investment portfolio of up to £200 billion (CCC, 2013b). The level of investment required to develop a low-carbon electricity supply system requires a policy framework that appeals to the investor community as well as promoting research and development for the emerging technologies such as CCS and new nuclear energy technologies.

In confronting the trilemma challenge facing the UK energy system, that is, decarbonising the electricity supply, maintaining security of supply and provision of affordable energy to consumers, the UK government introduced the electricity market reform (EMR) programme to finance the development of the electricity generation sector. This low-carbon financing programme was legislated through the Energy Act 2013 and it provides the basis through which a transition to a low-carbon electricity supply system could be achieved in the period to 2030. The estimated low-carbon generation capacity required to mitigate the UK energy trilemma would be driven by the EMR characterised by new reforms to the energy market in the form of Contracts for Difference (CfD) and Capacity Markets. Considering the level of capital investment required to develop a clean, secure and affordable electricity supply system consistent with the 2050 emission reduction target, it is imperative that the EMR programme is implemented in a consistent way that promotes and maintains investor confidence in the UK energy markets. The creation and maintenance of a functional energy market is a key driver in bringing forward the large scale deployment capacity of mature and emerging technologies required to clean up the electricity generation sector whilst maintaining the security of supply and the provision of affordable energy supplies to the UK economy.

1.3 The new UK energy policy: A roadblock to sector decarbonisation

After creating a radical policy platform for decarbonising the energy economy by 2050 (HM Government, 2008), the new UK energy policy appears to be heading towards a carbon intensive locked-in electricity generation infrastructure. The newly announced energy policy initiative (DECC, 2015a) is proposing an ambitious new gas plant renaissance to be supported by a new fleet of nuclear power plants and possibly with offshore wind if deployment costs do come down. In this new UK energy policy, a phase-out plan for the existing coal plants is proposed for 2025. Contextually, the proposed phase-out of coal generation by 2025 would have to take into account the likely scenario that could result in only one new nuclear energy plant commissioning by the end of 2030 out of a possible 16 GW capacity projected by the UK nuclear industry to be deployed in the same period (HM Government, 2013c). The prospects of a new nuclear energy plant renaissance in the UK electricity generation mix is currently not encouraging as the first planned new nuclear energy plant at Hinkley Point C is yet to reach the financial investment decision (FID). Hence, the future of a fleet of new nuclear energy reactors for the UK electricity generation sector remains worryingly uncertain.

A new dash for gas-fired generation in the period to 2030 appears to be a plausible solution to addressing two of the pillars of the energy trilemma, except decarbonisation. The low capital investment required to build new gas plants could provide the deployment momentum for gas-fired generation infrastructure expected by the UK policymakers to fill the capacity deficit likely to be created following the stall in new nuclear plant development and the retirement of existing old coal and nuclear electricity generation plants. As the new UK energy policy embraces energy security as its main priority, its focus on developing a low-carbon electricity supply future is further dented by the UK government's decision to stop funding the commercialisation of CCS technology. This implies that the new gas generation plants set to define the new energy policy may not be fitted with CCS to abate emissions.

Therefore, in the absence of CCS technology in the generation mix by 2030, the ambition to build a sustainable electricity supply infrastructure for the UK energy future by 2030 and 2050 could be impossible, let alone be aligned with the goal of keeping the UK economy on track to the 2050 emission reduction target. The case for new gas generation plants is contentious particularly in the face of the UK government's decision to end subsidies for onshore wind and solar PV, a decision which is widely believed to have an impact of increasing policy uncertainty in the future promotion and development of low-carbon energy investment markets.

The future direction of the current UK energy policy is difficult to predict. Therefore, it is not surprising that terms like "incoherent, unstable, inconsistent" (Scottish Government, 2015) have been used to describe the seemingly 'start and stop' approach apparently characterising the energy policy of late. The apparent lack of clarity and direction in the allocation of contracts at the capacity market auctions is arguably one of the key features where the new energy policy is seen to be presenting a conflicting framework on how the UK government intends to achieve the security of supply objective. The first two capacity market auctions have seen coal, small gas plant operators and diesel generators being awarded contracts at the expense of large gas plant investments, the sector which is supposedly meant to drive the security of supply agenda as unveiled by the new UK energy policy. At the backdrop of this seemingly conflicting policy framework, the prospects of the new gas generation plant renaissance aspired by the new UK energy policy could be difficult to achieve under the prevailing market environment for the gas generation sector.

The polarisation of the gas investment community through an ad hoc implementation of the capacity markets is not a price the UK government can afford to pay given the manifold factors currently working against the sector's potential contribution to driving the entire UK economy towards the 80 % emission reduction target by 2050. A depressed market for new gas generation plant development is not likely to benefit from the shale gas development projected to take-off in the mid-2020s (Economic Affairs Committee, 2014). Therefore, a series of attractive incentive mechanisms designed to promote a new wave of new gas plant development would need to be prioritised and fast tracked if the UK government remains strongly committed to the complete phase-out of coal generation by 2025. By so doing, this could create a viable domestic market for the prospective development of the shale gas resources in the UK, and thus bolstering the energy sovereignty objective sought by the new energy policy.

A new UK energy policy outlook by 2030 without CCS and potentially without new nuclear plants, but a new fleet of gas generation plants is not likely to get closer to meeting the emission reduction target of 100 gCO_2/kWh proposed for the fifth carbon budget set for the 2028-32 period. The role of offshore wind in driving this new UK energy policy is dependent on the technology achieving cost competitiveness as the UK government expressed unwillingness to subsidise offshore wind. However, if development costs for offshore wind does fall below the £100/MWh threshold (The Crown Estate, 2012), the UK government envisages that the sector could be funded to yield a total installed capacity of up to 20 GW by the 2020s (DECC, 2015a). While the development of a portfolio of offshore wind could contribute towards decarbonising the electricity generation sector, renewable energy technologies are variable by nature. This weather dependent power output characteristic of renewable energy sources poses a real threat to the UK security of supply objective, especially if the accelerated deployment of offshore and onshore wind and solar energy is not matched by a strategic plan to mitigate the impact of intermittency to electricity supply.

The dynamics affecting the UK electricity generation sector are so immense to the extent that the proposed phase-out of coal generation by 2025 may not happen. The existing energy market landscape and decarbonisation policies could provide a leeway that could potentially perpetuate the operation of coal in the UK electricity generation mix. Under these enabling conditions, there is a potential that the existing coal plants could be upgraded to comply with the pollution regulations as well as extend their operational life if the new gas plants fail to achieve the accelerated deployment levels anticipated by the new UK energy policy. It is in this context that a cocktail of carbon intensive generation technologies consisting mainly of unabated coal, gas and reciprocating diesel engines in the generation mix by 2030 could be detrimental to the sector's capacity to meet the fourth and fifth carbon budgets, let alone in assisting to keep the UK economy on track to the 80 % emission reduction target by 2050. Given the uncertainty in the development and direction of the new UK energy policy, it is difficult to determine how the UK government intends to fulfil its domestic legally binding emissions targets as well as contribute to the global goal of stabilising the global temperature rise blow the 2 ^{o}C threshold.

1.4 The dilemma of intermittent renewable energy resources

The transition of the power sector to low-carbon future is dependent on an accelerated deployment of renewable energy technologies. The increased penetration of low-carbon and renewable energy technologies aims to displace the high carbon intensive fossil fuels from the electricity generation mix. The UK government estimates that 40 to 70 GW capacity of low-carbon generation would need to be deployed through the 2020s to guarantee security of supply as well as decarbonise the sector by 2030 (HM Government, 2011). A large proportion of this low-carbon energy capacity development comprise of renewable energy technologies such as wind, solar, wave and tidal, whose output is influenced by environmental conditions. The variance of intermittent output from these renewable energy technologies have diverse implications on the operation of the entire energy supply system. With offshore wind projected to play a major role in guiding the power sector to a low-carbon energy future, this thesis uses statistical wind data and wind turbine power characteristics to quantify variable power output from offshore wind and its implications on policy and the energy supply system outlook by 2030.

Since the model framework used in this thesis does not consider and reflect the impact of variability on renewable energy sources in its scenario outputs, a study on wind variability is designed to quantify and integrate this element in the model structure. By addressing the limitations of the model in addressing the issue of intermittency, it is anticipated that the scenarios developed by the model could contribute significantly in providing insights into the development of the future energy policy and the electricity supply infrastructure. The level of variability of offshore wind output established through the wind data analysis is used to determine the amount of reserve unabated fossil fuel capacity that could be required to mitigate any supply deficit. The frequency at which unabated fossil fuel plant is operated to mitigate fluctuations in offshore wind output has a cost and emission penalty on the operation of the energy system. Therefore, by integrating the full impact of variability of renewable energy sources into the modelling framework, the results from this thesis could shed valuable insights into the development of policies, technology and investment strategies for the UK low-carbon energy futures.

1.5 Aim of this study

The literature review analysis presented in Chapter 2 has revealed the challenges facing world communities in their quest to achieve energy sovereignty while minimising the threat of dangerous climate change. The global energy policy landscape has been defined by a system of targets seeking to drive energy economies towards low-carbon futures through the transformation of energy supply systems. The energy security and decarbonisation have been entrenched in the national and regional energy and climate policy fabric, and thus underscoring the strong link between the energy transformation processes and the threat of climate change and energy sovereignty. Various approaches have been developed and deployed to explore the evolution of energy economies towards low-carbon futures.

This thesis uses the (EOC) to trace the evolution of the UK electricity generation infrastructure to a low-carbon future consistent with the legally binding emission reduction target of 80 % by 2050 against the 1990 level. The analysis adopted in this research endeavours to capture the low-carbon transition of the UK electricity supply sector under a policy framework experiencing insurmountable pressure to reconcile the technical, economic and climate facets of energy system development against the national objective of achieving security of supply and affordable energy to the UK population. Following up on the gaps identified in the literature review presented, the principal research question and a series of sub-questions are proposed in this thesis to provide the platform through which the UK energy policy trilemma can be discussed in the context of the dynamics affecting the electricity generation infrastructure.

The principle research question at the heart of this thesis is: *how can the technical, economic and political components of the UK energy system development be effectively aligned to transform and guide the electricity generation infrastructure to a low-carbon future by 2050?*

A series of sub-questions have been adopted to provide the necessary structure in the form of result chapters which form the arenas where the investigation of this research question is deliberated in greater detail. The following sections provide a selection of the research sub-questions with a brief description of the main aspects covered in each:

RSQ1: How can a transition to a low-carbon energy future be conceptualised in the context of technical, economic and decarbonisation constraints?

This section of the research question explores alternative approaches that have been employed to investigate the evolution of energy systems in the quest to develop an optimal electricity generation mix that achieves the key facets of the energy trilemma.

RSQ2: To what extent is the current UK energy policy intervention a threat to the objective of decarbonising the electricity supply sector?

An abrupt disconnect to the Climate Change Act oriented energy policy framework precipitated by the newly unveiled UK energy policy is creating a degree of uncertainty within the entire energy system development and transition. The apparent lack of policy continuity is posing a major risk to the technical, innovation and investment aspects of the energy system development. This uncertainty in the energy policy which is created by a series of incoherent decisions present a major risk in balancing sustainability, security of supply and affordability priorities.

RSQ3. How can the potential shale gas resource development and use in the UK electricity generation sector achieve the environmental sustainability and security of supply objectives of the UK energy policy?

With a legal binding emission reduction target in place, the prospects of a shale gas 'revolution' would put to test the UK government's commitment to decarbonising the electricity generation sector. The potential energy resource independence likely to be enhanced through the development and use of locally sourced unconventional gas could create conflicts within the energy policy framework if a balance between sustainability and energy security is not struck in the exploitation of this resource.

RSQ4. How can we use insights and knowledge derived from the analysis of intermittent renewable energy resources to evaluate the role of renewable energy technologies in low-carbon energy transitions?

As the UK electricity generation supply system transitions to a near zero carbon grid intensity by 2050, an unprecedented level of renewable energy technologies would have to be deployed to achieve this level of decarbonisation. While the deployment of these technologies is fundamental in decarbonising the electricity supply system, their variability characteristic can pose a threat to the security of energy supply. It is through the RSQ4 that the full extent of intermittency of renewable energy technologies can be explored in its entirety as the energy supply system transitions to a low-carbon future.

1.5.1 The structure of the thesis

This thesis is comprised of seven chapters as shown in Figure 1.1. The introduction presents an overview of the energy supply systems and their impact on the goal of keeping global temperatures below 2 ^{o}C of pre-industrial levels from a global, EU and UK perspective. Furthermore, the focus of the introduction shifts to illuminate on the challenges facing the UK energy policy in balancing the technical, financial and sustainability aspects defining the energy system in transition to a low-carbon future. The thesis devises a series of research questions to present a chronological assessment of the main concepts defining the evolution of the UK energy policy as shown in Figure 1.1. Chapter 2 gives an exposition of the body of literature currently available to shed insight into the developments affecting the transition of energy systems to a low-carbon future. Also, the literature review contains a review of related concepts and features in the studies involving energy transitions. The methodology section in Chapter 3 alludes to the EOC, the approach used to investigate the UK energy system transition to a low-carbon future. Through this simulation approach, a series of scenario assessments are generated in order to develop insights into the transition of the UK electricity generation sector in line with the principles of the energy trilemma. A section of Chapter 3 is devoted to model testing, an exercise seeking to establish the model calculator's robustness and suitability for use in developing energy scenario frameworks for this thesis.

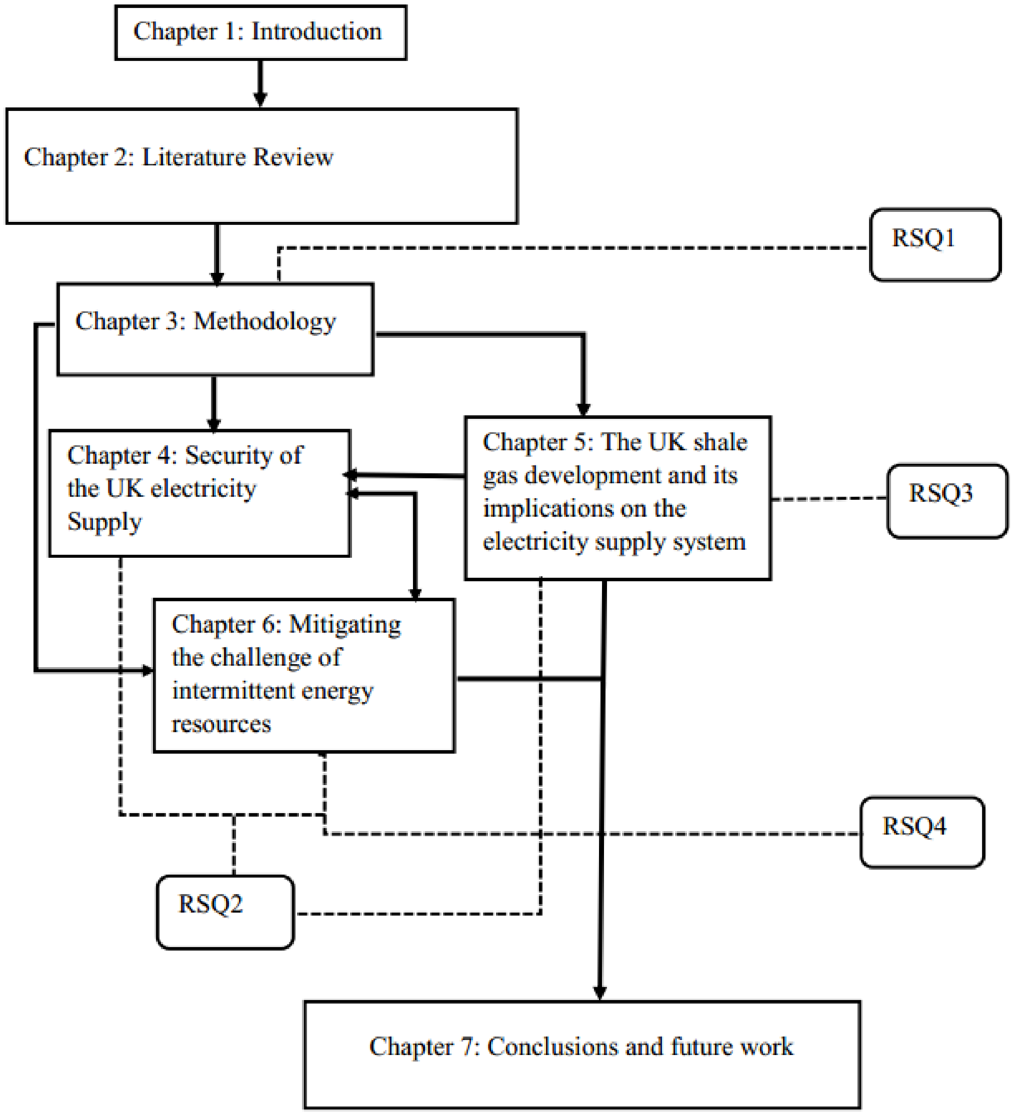

Figure 1.1. The thesis structure and the connecting research sub-question framings.

The results section is made up of Chapters 4, 5 and 6, which form the main body of this thesis where the dynamics affecting the UK energy policy are discussed in the context of the principle research question and the sub-questions outlined in Section 1.5. Chapter 4 explores the potential threats to the UK security of electricity supply in view of technical, investment and policy dynamics affecting the development of the energy system. Chapter 5 introduces the UK shale gas development and its potential wider implications on the decarbonisation of the UK electricity generation sector and the general transition towards a low-carbon energy future. It can be concluded that chapters four and five bring to life the dilemma confronting the UK policymakers in trying to achieve a balance between security of supply and climate change, the two key pillars of the UK energy policy objectives. The impact of variability from renewable energy technologies in the generation mix is discussed in Chapter 6 with its related effects on security of supply, the operation of reserve gas CCGT generation and the carbon emission generation. Furthermore, this chapter reviews the limitations of the EOC in addressing the issue of variability and its impacts on the development of future low-carbon energy scenarios. The thesis signs off with Chapter 7 which provides concluding remarks from the research in its entirety. A designated section on future work within this chapter outlines ideas that emerged during the course of the research, which by virtue of the level of detailed required to analyse them could not be incorporated within the current thesis. Therefore, these emerging ideas could form new areas of research which could be deemed to be of great benefit to this thesis, and as such, they are set aside to form part of the future work.

Chapter 2 Literature Review

2.1 The global energy production, use and climate change

The energy industry is arguably the largest contributor to global greenhouse gas emissions as the current electricity generating infrastructure is still heavily dependent on carbon intensive primary fuels such as coal and natural gas. Decarbonising the electricity supply system is not only a catalyst for reducing air pollutants and GHG emissions, but it is also essential for stimulating economic growth and enhancing energy security. The proportion of the global electricity generation infrastructure portrayed in Figure 2.1 confirms the dominance of fossil fuels, and hence the level of investment, policy and innovative challenges that would need to be overcome in order to decarbonise the sector. With 3606 GW, that is, 65 % of total installed capacity in 2012 shown in Figure 2.1 comprising mainly of coal, gas and oil, confirms the International Energy Agency (IEA) assessment that fossil fuels will continue to meet more than 80 % of the primary energy demand and that over 90 % of the energy-related emissions of carbon dioxide are from fossil-fuel combustion (IEA, 2015).

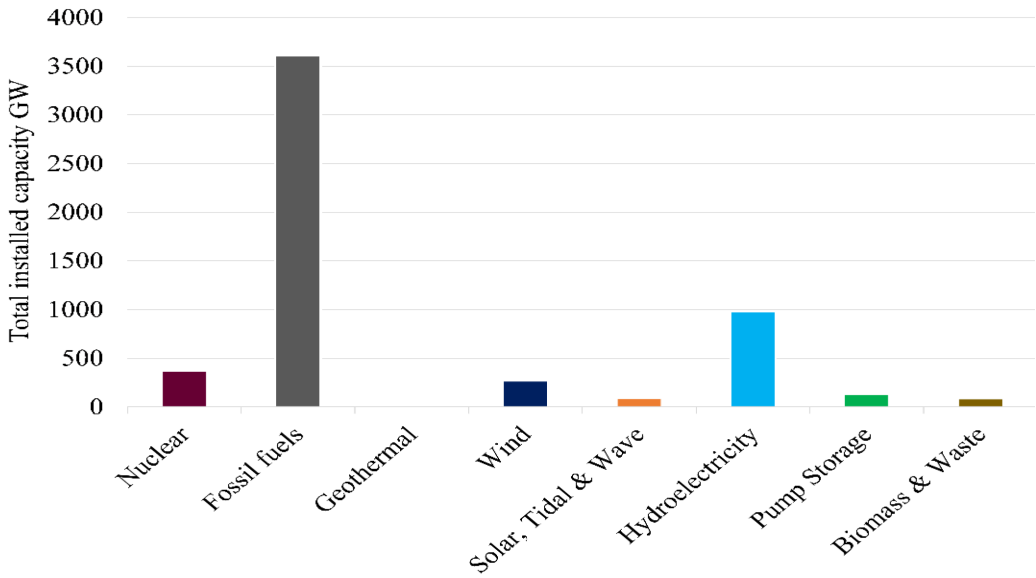

Figure 2.1. The 2012 global installed electricity generation capacity (EIA, 2012).

The insatiable global demand for energy, which is spurred by the ever increasing economic and population growth, could increasingly make it more difficult to reduce emissions to levels commensurate with the internationally agreed goal of keeping the temperature increase below 2 ^{o}C, relative to the pre-industrial times

(IPCC, 2014b). Early action in the form of switching from high carbon intensive technologies to low-carbon energy alternatives such as nuclear, CCS and renewable technologies is imperative for decarbonising the electricity supply system. However, based on the 2012 electricity generation capacity distribution shown in Figure 2.1, the global initiative towards a low-carbon electricity future needs to be accelerated to increase the build-up of wind, solar, and other low-carbon energy technologies that are fundamental for stimulating sufficient decarbonisation of the electricity generation infrastructure.

The penetration of individual renewable and low-carbon technologies and their capacity to mitigate climate change and energy security issues can be hampered by a wide range of constraints. Economic factors, environmental concerns, public acceptance and the integrative nature of the existing infrastructure could hinder the deployment potential of various renewable and low-carbon energy technologies. Nonetheless, in the context of global warming, there should be no compromise, but to decarbonise the ‘high carbon lock-in’ generation infrastructure. The case against fossil fuelled economies was hinted in a recent nature study which suggested that a third of oil reserves, half gas reserves and over 80 % of current coal reserves should remain unused from 2010 to 2050 in order to meet the target of a 2^{o}C reduction target (McGlade & Ekins, 2015).

However, the problem of “lock-in” by existing high emission technologies, political, regulatory and social systems could make the goal of limiting the rise in global mean temperature to the 2 ^{o}C target much costlier and more difficult to achieve (IEA, 2012). These transitional barriers to a low-carbon global electricity supply system are reinforced by the absence of an agreed global framework to enforce climate change mitigation measures. Therefore, there is a need for the development of a policy framework that prioritises and supports energy supply technology development and deployment.

The power sector, particularly the electricity generation system is central to climate abatement. Traditionally, coal has been and continues to be the backbone of power generation for the global electricity demand and by so doing, it is believed to have contributed more than 40 % of the worldwide energy-related CO_2 emissions growth since 2000 (IEA, 2015). The Intergovernmental Panel on Climate Change (IPCC) asserts that approximately 35% of the total anthropogenic GHG emissions in 2010 were derived from the energy supply sector, with an increased share of coal in the global fuel mix being one of the main contributors (IPCC, 2014a). Shifting electricity supply from fossil fuel to clean energy alternatives requires strong and drastic policy interventions to accelerate the investment in low-carbon energy technologies, as well as adopting an incentivised framework to phase out coal generation in the long-term. The development of an overarching policy strategy for the global electricity sector, which balances environmental and energy security concerns, is dependent on a thriving and internationally established agreement on climate change mitigation. The absence of a strong global initiative is a roadblock to each country's motivation and willingness to formulate and implement domestic climate policies as well as the establishment of credible investment structures to accelerate technology innovations for low-carbon technology transitional purposes.

Significant reductions in the role of coal-based electricity generation, accompanied by a low-carbon and renewable energy technology revolution underlines the current global climate change and energy security policy rhetoric. While this policy paradigm is central to decarbonising the global economies and achieving energy sovereignty, the challenge lies on the extent to which this policy framework could be unpacked in communities and constituencies ravaged by widespread energy deprivation. According to the Organisation for Economic Co-operation and Development (OECD, 2010), there are 1.4 billion people globally that lack access to electricity, with 85 % of them predominantly in rural areas. This state of energy deficiency and deprivation creates further strain on local resources as communities struggle to find sustainable alternatives to meet their energy needs.

With an estimated 2.4 billion people relying on traditional biomass fuels (Modi et al., 2005), there is growing fear that such dependency on biomass fuels could accelerate environmental degradation as well as the health and wellbeing of poor communities dependent on these unsustainable biomass-derived fuel resources. Energy underdevelopment challenges particularly in poor-emerging economies need to be given the same attention as that accorded to the climate change and security of supply issues at global forums hosted and promoted by the developed market economies of the OECD (Birol, 2007). A balanced policy approach could not only heighten the scourge of energy deprivation in poor communities in Sub-Saharan Africa, South Asia and South East Asia, but could assist in alleviating fuel poverty by providing financial and technical support that could promote economic growth and the social wellbeing of communities in developing countries as they transition to sustainable energy development futures.

Therefore, it is crucial that a global energy policy framework that fosters an understanding of the relationship between energy security, environmental sustainability and fuel poverty is developed and implemented to address energy-related challenges affecting worldwide economies. The adoption and application of a globally integrated energy policy, even in energy deprived communities, could contribute significantly in addressing energy related issues transcending across geographical boundaries. Since the poor-energy emerging economies currently lie outside the emission reduction framework, Bradshaw (2010) expresses the opinion that an integrated policy approach would have the advantage of keeping their energy and emissions within the carbon emission reduction framework, and thus assisting in reducing the challenge of stabilisation and reduction of global emissions. Also, it is envisaged that through increased investment and technology sharing, the energy-poor emerging economies' future growth in energy service demand could be met with greater efficiency especially from low-carbon energy resources that have a higher potential to improve energy security and keep carbon emissions in check (Bradshaw, 2010).

2.2 The European Union's framework for a sustainable electricity future

2.2.1 Brief energy policy overview

In its quest to contribute towards global decarbonisation, the EU launched its Energy Roadmap 2050 which explores various approaches to transitioning towards a cleaner energy system. Its decarbonisation agenda is underpinned by the "20-20-20" targets where a 20 % reduction commitment on GHG emissions, renewable energy resource deployment and energy efficiency was adopted by Member States (European Union, 2012). Keeping abreast with the 50 % global emission reduction target commensurate with the 2 ^{o}C objective, the European Council endorsed the long-term goal of reducing EU GHG emissions by 80-95 % by 2050, relative to 1990 levels, in the context of similar reductions committed by other developed countries (European Council, 2009).

As the concentration of GHG emissions continue to rise within the atmosphere with no binding international agreement in sight, the European Commission has proposed a binding 40 % target for GHG reductions and 27 % target for the renewable energy resources deployment by 2030 (Erbach, 2014). The adoption of these targets sends a strong message to the global community, particularly to other developed countries outside the EU on the need for a binding international agreement on greenhouse gas emission reduction. Collective effort by both developed and developing nations is urgently required to facilitate a 50 % fall in global emissions compared to the 1990 level by 2050, which effectively equates to a 60 to 80 % reduction by most developed countries by 2050 (European Comission, 2007).

2.2.2 The dilemma of security of energy supply

While leading the fight against climate change, the EU policy has also been dominated by the energy security narrative. Taken in a wider context, the “20-20-20” package combined with the 2030 and 2050 milestones have an overarching objective of mitigating climate change while at the same time attempting to address the EU’s insecure fossil fuel economy which is heavily dependent on foreign energy sources. With a diversified source and supply of imported hydrocarbons, the EU energy system and economy is still vulnerable to supply disruptions and incessant price vitalities owing either to the political instabilities, commercial disputes or infrastructural failures arising along the gas transitional routes or within the Russia-Ukraine boarders.

The magnitude of this vulnerability to imported energy supply is aggravated by the EU’s over-dependency on one single external supplier, which in this case is Russia. Based on the 2013 figures, Russia supplied 39 % of the EU natural gas imports which represents almost two fifths of the total EU imports (European Comission, 2014). There is a risk associated with such over-dependency on one supplier, who as observed by Toke and Vezirgiannidou (2013) can use such a position for geo-political gain. The development of an integrated and diversified network of gas corridors from the Caspian region and Middle Eastern resource routes as unveiled in the “Energy Security and Solidarity Action Plan” (European Comission, 2008), underscores the goal of fostering an uninterrupted physical availability of energy. This focused investment in a diverse intercontinental fossil fuel gas infrastructure linking Europe with its primary energy suppliers confirms the IEA’s assessment that about 70 % of the energy supply investments today are related to fossil fuel extraction, transportation and transformation (IEA, 2010).

However, as observed by Tricarico and Gerebizza (2012), the channelling of billions of euros into large fossil fuel based infrastructures appears to be at odds with the decarbonisation and sustainability aspirations projected through the “20-20-20” objectives, the 2030 target of 27 % renewable energy resource as well as the 80-95 % emission reduction by 2050. This kind of investment could perpetually ‘lock-in’ the EU economy, and in particular the energy system to fossil fuels with the detriment of further increasing emissions into the atmosphere.

2.2.3 The EU era for renewable energy development

In the long-term, the EU is committed to protecting its economy from the external vulnerability to imported hydrocarbons by ensuring that the 20 % and 27 % proposed share of renewable energy supply is achieved by 2020 and 2030, respectively. The EU’s renewable energy deployment landscape appears to be making significant gains as an estimated 14.1 % renewable contribution to final energy consumption was achieved in 2012 compared to 8.7 % in 2005 (European Comission, 2014). The growth in the renewable energy sector is mainly driven by the renewable energy support scheme stimulating investment in solar photovoltaic (PV) and onshore wind. Latest figures from 2013 indicate that 25.4 % of the EU’s gross electricity consumption was derived from renewable energy sources with the bulk of the output derived from hydroelectricity, wind turbines, solar and biomass (Eurostat, 2015b) as shown in Figure 2.2.

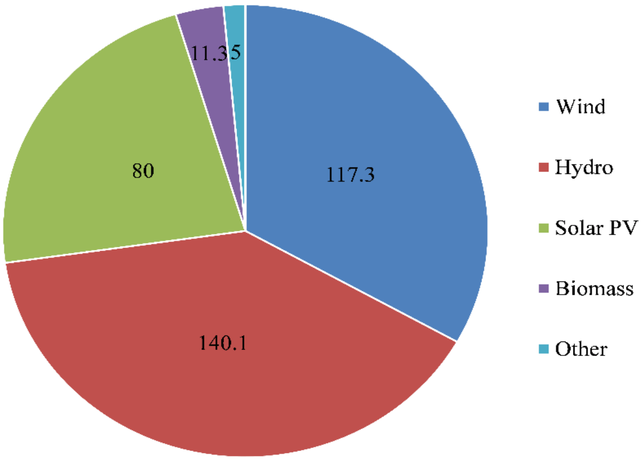

Figure 2.2. Installed renewable capacity in EU in 2013 (EWEA, 2014 p 8).

The increased share of renewable energy capacity in the generation mix has seen a gradual rise in the annual contribution to the gross electricity supply in the EU from 2004 to 2013 as highlighted in Figure 2.3. The penetration of renewable energy resources across the EU has led to 25.4 % increase in the overall electricity supply being sourced from renewable technologies as shown in Figure 2.3. This remarkable penetration of renewable energy technologies into the electricity generation mix is driven by a policy framework which seeks to transform Europe's energy system. Renewable energy development is essential to the EU energy system as it contributes in meeting all the Energy Union objectives such as the delivery of security of supply, a transition to a sustainable energy system with reduced greenhouse gas emissions and industrial development which leads to growth, job creation and lower energy cost for the EU economy (European Commission, 2015). The continuity in the existing renewable energy policies within the Member States could sustain the momentum in renewable energy deployment demonstrated in Figure 2.3, and thus increasing EU's potential to achieve the 2020 and 2030 targets.

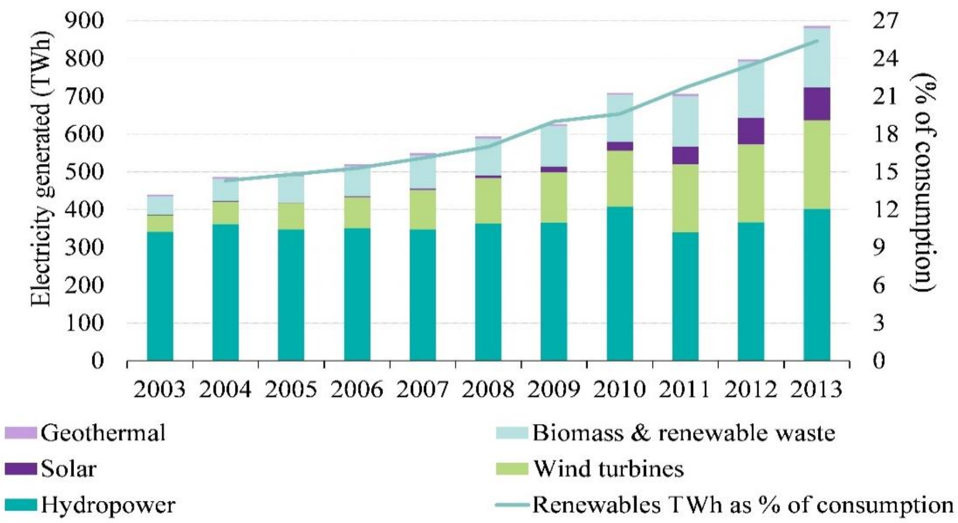

Figure 2.3. The EU percentage share of electricity from renewable sources (Eurostat, 2015a).

2.2.4 The future of coal-fired electricity generation in the EU

Fossil fuel generation, mainly from coal and gas will continue to be Europe's dominate electricity generation system, both in the short and medium-term, that is, 53 % in 2010; 43.5 % in 2020 and 39.8 % in 2030 (European Comission, 2010). The dominance of fossil fuel generation in the energy mix, which accounted for about 419.9 GW in 2013 (EWEA, 2014) could pose a major obstacle to the EU's policy attempts to find the right balance between sustainability, competitiveness and security of energy supply issues. The competitiveness of coal prices over gas in the EU has strengthened its market share in the generation mix. This has been facilitated partly by the increased coal imports from the US displaced by the increased switching to gas in the power generation sector following the boom in shale gas, as well as the impact of the emissions regulations (Lu et al., 2012). The depreciation of the carbon prices in the European Union Emission Trading Scheme (EU ETS), that is, from €28/t before the 2008 economic crisis, to less than €5/t for most of 2013 (Honore, 2014), has further consolidated the coal generation position as the most favourable alternative to gas despite its higher carbon intensity. The collapse of the carbon market system as a driver for decarbonisation is believed to have accounted for the 38 % emissions recorded in the power sector in 2012 (IEA, 2014a).

The future role of coal in the generation mix is dependent on the compliance of both existing and new plants to the EU environmental regulations in the form of

Large Combustion Plant Directive (LCPD) and Industrial Emissions Directive (IED). These pollution regulations seek to reduce acidification, ground level ozone and particulates by controlling the emissions of sulphur dioxide (SOx), oxide of nitrogen (NOx) and dust particles (pm10) from large combustion plants. As a result of these pollution regulations, it is estimated that about 55-60 GW coal capacity will be shut down across the EU by the end of 2015 (Honore, 2014). The investment challenges to upgrade the coal generation infrastructure to meet the higher national and EU emission standards and other political and market pressures could combine to fast track the coal generation infrastructure closures, particularly on aging energy plants.

While coal contributes about 27 % share in electricity generation at EU level (EURACOAL, 2013), its long-term future role in the energy mix can only be enhanced and consolidated through the adoption of the best available technologies such as Carbon Capture and Storage (CCS) and other advanced systems that achieves higher efficiency measures. The sustainability of fossil fuel power plants, that is, their capacity to attain a near-to-zero emission status hinges on the commercial viability of CCS technologies. As a climate change mitigation option, a CCS process consists of capture, transport, deposition and monitoring of CO_2. The components of the CCS chain are in commercial use today elsewhere in the economy, but are yet to be used in an integrated chain envisaged for mitigating carbon emissions from industrial processes in Europe. The successful roll-out of CCS technology in the electric power sector requires sufficiently stringent limits on GHG emissions to make it economic to incur additional costs, regulatory mandates that would require the use of CCS or direct or indirect financial support (Herzog, 2011). The progress in CCS development and deployment does not rest on technical and financial barriers alone, but also on the political appetite of individual governments as well as on public acceptance.

The successful transition of the EU coal infrastructure towards clean technologies is eagerly anticipated, especially at the backdrop of heightened gas security concerns as well as energy security dilemmas associated with the increased share of intermittent generation in the electricity supply mix. Generally, the outlook for coal in an energy system transitioning to a low-carbon future is limited, however, the current slow progress in CCS development and the potential investment risks for new coal and aging plant upgrades could further decrease the long-term coal capacity in the EU generation mix. In the event of a legally binding carbon target being agreed in Paris in December 2015, there is a danger that coal plants in the EU could be stranded, thus aggravating the EU's electricity infrastructure capacity to address the challenges of meeting the future energy demand, promoting diversity of supply and supporting large scale intermittent generation in the system.

2.2.5 The role of natural gas and shale gas in EU energy transition

Gas-fired power plants in Europe face an uncertain future in the generation mix mainly due to the boom in renewables, lower coal prices, lower power demand and the collapse of the CO_2 emissions prices in the EU ETS, and thus making gas generation less competitive. These factors have successfully created stranded gas generation infrastructure, a phenomenon described by Caldecott and Mcdaniels (2014) as that depicting assets that become uneconomic to operate when their marginal cost of generation exceeds the price for electricity over an extended period of time, and thus leading to them being temporarily idle or shut down (mothballed), or permanently retired ahead of their planned decommission.

Despite being considered the most flexible thermal base-load technology ideally suited to mitigate the challenges of increased intermittent generation in the energy mix as well as assist in future decarbonisation, combined cycle gas turbine (CCGT) plant future under the prevailing market climate is bleak. Expert reports estimate that about 110 GW CCGT capacity across Europe could be retired or mothballed within the next few years (Caldecott and Mcdaniels, 2014), and thus compromising on the EU security of supply as well as climate change objectives. While price differentials between coal and gas are projected to remain unchanged over the foreseeable future, the resurgence of gas competitiveness can only be thought of depending on the extent and impact of nuclear and coal closures through the 2020s.

As the natural gas price remains at a record high level and is projected to remain unchanged in the foreseeable future, one could hope that the US "shale gas revolution" could spill over the EU continent with similar impacts, particularly on the gas markets. With 472 trillion cubic feet (tcf), see Figure 2.4 of the potential recoverable unconventional gas resource estimated for the EU (EIA, 2013), shale gas development could potentially boost EU security of supply by lowering natural gas prices, guarantee gas supplies on the EU markets and adding diversity to the EU's gas pipelines (Pearson et al., 2012). Although this resource estimate map could change over time as more explorations are undertaken, the shale gas resource potential portrayed in Figure 2.4 is a welcome development given the decline in the indigenous gas production across EU producing regions.

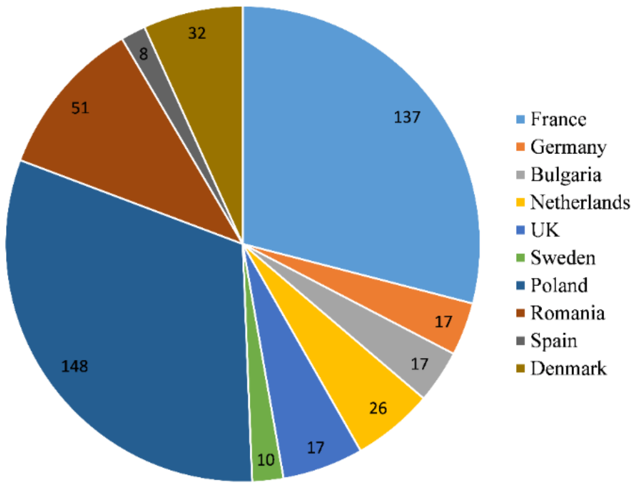

Figure 2.4. Unproven technically recoverable shale gas resource (Tcf) (EIA 2013).

At the backdrop of this prospective EU shale gas potential, most analysts concur that the development of this resource in Europe could be more expensive than in the US due to differences in geology, and the need to address public acceptance and environmental impact (Erbach, 2014b). It is also understood that environmental constraints or potential environmental compliance costs could prevent significant volumes of unconventional shale gas development (Pöyry, 2011). On the other hand, these benefits likely to arise from the successful integration of shale gas in the EU's electricity supply sector could come at the cost of increased environmental degradation and the potential risk of induced seismic activity. Furthermore, the development of unconventional shale gas in the EU could be deemed retrogressive to the EU-wide energy and climate change strategy if cheap gas discourages investments in energy efficiency and renewable energy sources (Erbach, 2014b).

To this end, unconventional gas exploration in the EU and its potential development in the future has been received with widespread scepticism, leading to some EU countries imposing moratoria on hydraulic fracturing processes

(Johnson & Boersma, 2013). France, with an estimated 137 Tcf of potential shale gas resource, the second largest in the EU after Poland, (see Figure 2.4) has together with countries such as Bulgaria and Spain, imposed a moratorium on shale gas exploration and extraction citing many uncertainties overshadowing the industry as well as potential impacts on the environment. Assuming that the combustion of natural gas has less carbon dioxide emissions and is potentially the cheapest and fastest means of decarbonisation compared to other fossil fuels, it is argued that the increased development and use of shale gas in electricity generation could play the role of a ‘bridging fuel’ until a permanent transition to renewable source of energy can be achieved (Johnson & Boersma, 2013; Pearson et al., 2012). It is widely believed that the future climate impact of shale gas could be positive if it replaces carbon intensive coal, and that fugitive methane emissions are tightly regulated from the extraction, processing and throughout the supply chain.

2.2.6 Nuclear energy challenges in the EU generation mix

Although nuclear safety is a major concern, to global electricity supply networks especially after the Fukushima disaster, 26.9 % of electricity was derived from nuclear plants in 2014 (World Nuclear Association, 2015). Therefore, this consolidates nuclear power status in the EU as a competitive, reliable and base-load energy source. Despite the terrible impact of the Fukushima disaster over global energy economies, the EU still believe that within a diversified fuel and technology supply base, nuclear power plants can assist in ameliorating the energy security concerns as well as decarbonising the regional economy. However, the future of the nuclear energy industry is currently facing tough challenges within the EU. On the path to 2030, there are stronger indications that a proportion of the 122.3 GW nuclear installed capacity (EWEA, 2014) could be lost due to the closure of a number of reactors as they reach the end of their operating life or due to political opposition. In their analysis of nuclear energy in the World Nuclear Industry Status Report 2014, Schneider et al. (2014) ascertained that in the period 2000 to 2013, nuclear decreased by 13 GW compared respectively to 105 GW, 103 GW and 80 GW increases in wind, natural gas and solar installed capacities. The level of plant closures will vary among the EU Member States depending on political, investment and public perception.

Under the existing EU low-carbon energy oriented policies, the greater penetration and use of renewable energy technologies could undermine the operating regime of both fossil fuel and nuclear plants. Based on Eurelectric analysis, the impact of the accelerated penetration and use of renewable energy has seen the average operation hours of Spain's CCGT plants fall from 5-700 hours in 2004, to below 1000 hours in 2013, while in Italy, gas plant operation fell from 5000 hours in 2007 to below 3000 hours in 2012 (Eurelectric, 2014). This trend is likely to continue in the foreseeable future as the global investment in nuclear and fossil fuel plants continues to trail that of renewables. According to the EIA, the 2000-2013 global investment in power plants shows the dominance of renewables with 57 %, fossil fuels 40 % while nuclear accounted for just 3 % (IEA, 2014b). The investment outlay to 2035 for the electricity generation technologies was estimated to be about US$700 billion for wind and solar, with an additional US$300 billion for hydroelectricity compared to less than US$600 for both fossil fuels and nuclear combined (IEA, 2014b). Given the deeper decarbonisation commitments earmarked for the period to 2030, the EU's energy and climate targets could continue to undermine the operational regime and ultimately the financial viability of nuclear power plants. As the future of the EU new-build nuclear plants remain shrouded in uncertainty owing to high investment costs and policy uncertainty, the regional commitment to decarbonise the electricity sector and the economy could be compromised.

2.3 Developing a clean and secure electricity system for the UK 2050 future

2.3.1 UK electricity policy development overview

A transition to a sustainable electricity generation future is a priority to the UK energy policy development framework. Faced with the threat of dangerous climate change and the uncertainty over the current electricity supply infrastructure's capacity to meet the challenges of future electricity demand likely to be exacerbated by the increased deployment of variable renewable generation, the UK energy policy would have to transform and adapt to these transitional issues. In response to the global challenges of climate change and domestic energy security concerns the UK government set a legally binding target to cut GHG emissions by

80 % by 2050 against the 1990 levels (HM Government, 2008). The UK electricity sector is dominated by fossil fuels which account for 63.7 % of the total generation derived mainly from coal, gas and oil as illustrated by the 2013 figures shown in Figure 2.5.

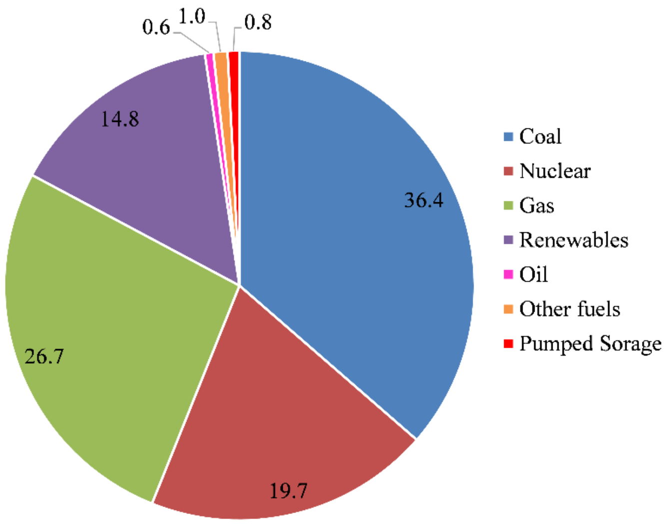

Figure 2.5. Percentage total electricity generation in the UK - 2013 (DECC, 2013).

Since the power sector accounted for 27 % of the total emissions in 2010 (HM Government, 2011), the CCC proposes that the sector should reduce its grid emission intensity from 500 gCO_2/kWh to 50 gCO_2/kWh by 2030 and to almost near zero in 2050 (CCC, 2010). Contrary to the CCC's strong recommendations for the adoption of a cost-effective approach to achieving the 2050 target without putting strain on other sectors of the economy, the government assessments appears to consider or favour a 100 gCO_2/kWh and 200 gCO_2/kWh target as possible alternative decarbonisation targets that could be adopted to transform the electricity sector by 2030 (DECC, 2012). The uncertainty over the 2030 decarbonisation target could possibly be resolved by the end of 2016, a date by which a decision could be made as to whether to impose a decarbonisation target on the electricity sector or not.

In order to monitor the nation's progress towards the 80 % emission reduction target by 2050, the Climate Change Act enacted a system of carbon budgets which set a 50 % emission reduction target to be achieved by 2025, the mid-point of the fourth (2023-27) carbon budget (CCC, 2013). While the government remains committed to establishing a sustainable electricity system, this could be achieved through a robust and strategic policy framework that could create an infrastructure base with a capacity to address climate change requirements while adapting to the challenges of meeting the future demand for electricity, facilitating diversity of supply as well balancing the system that is likely to overwhelmed by the large scale renewable energy deployment. The development of such a policy framework would not only address pressing energy policy challenges for the UK, but would also ensure the EU's 15 % mandated renewable energy target is achieved by 2020 (HM Government, 2009).

The UK coal-fired and nuclear generation fleet is facing potential closure, by the end of 2023, as they reach the end of their operational life. The decommissioning of coal-fired plants could be accelerated by the combined impact of the LCPD and IED owing to the investment challenges of retrofitting expensive abatement technology to comply with the pollution regulations. According to Skillings (2013), about 15 GW capacity is likely to 'opt-in' to the IED and undertake refurbishments to meet the EU environmental pollution standards. Despite the potential of coal-fired generation to be operational beyond 2023, the EMR unveiled policy measures aimed at delivering a decarbonised electricity system with a capacity to maintain sufficient generating capacity with minimum costs to consumers (DECC, 2014). As part of the EMR, the emissions performance standard (EPS) seeks to limit annual CO_2 emissions from new fossil fuel power stations to 450 gCO_2/kWh, which is designed to prevent coal-fired stations from being built unless they are fitted with CCS to mitigate emissions (DECC, 2011a).

While maintaining a stranglehold on heavy polluters, the carbon price floor (CPF) promotes low-carbon investment by introducing a carbon pricing mechanism based on the 'polluter pays principle'. The CPF came to effect on April 2013 at £16/tCO_2 and is expected to follow a linear trajectory to achieve a target of £30/tCO_2 and £75/tCO_2 by 2020 and 2030, respectively (HM Treasury, 2011). However, the 2013 Budget reformed the CPF and caped the carbon price at £18/tCO_2 from the 2016-17 to 2019-20 period, citing the need to protect and support the UK business competitiveness, restrain increases in household bills while maintaining incentives for low-carbon investment (HM Revenue & Customs, 2014). The prevailing economic and policy landscape appears to be favourable for coal generation, and hence this bolsters the chances of continued coal operation beyond 2023. The exclusion of the existing fossil fuel plant from the provisions of the EPS, a freeze on the CPS and the inclusion of coal in the capacity market mechanism indirectly signals the perpetuation of the coal legacy in the UK generation mix through the 2020s.

At the backdrop of this seemingly coal-enabling EMR policy, a recent study on the future of the UK coal generation in the mix concluded that, potentially 5-9 GW capacity could still be operational by 2030 at the detriment of the decarbonisation ambitions (Gross et al., 2014). The prospects of nearly 15 GW coal-fired capacity opting-in the IED and their eligibility to participate in the capacity market mechanisms pose a great threat to new gas investments as well as on the existing gas plants that have been withdrawn from system and mothballed due to the prevailing unprofitable operating conditions (Skillings, 2013). Conversely, the analysis set above suggests that the security of supply and the provision of affordable energy to consumers could be fulfilled by the EMR framework with coal in the generation mix.

Out of the 9.39 GW operational nuclear capacity in the UK to date, 7.143 GW capacity is planned for closure by the end of 2023, leaving 2.248 GW to continue operating beyond 2023 (Nuclear Industry Association, 2015). However, it is understood that an average of five-year life extensions for plants due for closure by 2023 is being considered by the operator subject to commercial viability and compliancy with security requirements (EDF Energy, 2015). This is a welcome development for the policymakers who otherwise could have been planning for the combined loss of about 20 GW of existing generation capacity with profound implications on the nation's security of supply over the next decade (DECC, 2011b). In anticipation for a significant capacity deficit due to plant closures and future growth in demand, the CCC's analysis estimates that 30-40 GW of low-carbon capacity needs to be developed in the decade from 2020, with about 45 GW required to decarbonise the sector to 50 gCO_2/kWh (CCC, 2013b). To this end, depending on future demand and generation mix, projections supplied by UK nuclear industry and the government indicate plans to deliver 16 GW capacity of new nuclear power plants, a 10 GW outlay of fossil fuel plants fitted with CCS technology by 2030 (DECC, 2012a; HM Government, 2013).

With the decarbonisation of the electricity generation infrastructure high on the UK policy agenda, the renewable energy contribution to 2030 could potentially result in 25 GW onshore wind, and 25-40 GW offshore wind installed capacity delivered by 2030 taking into account the regulatory and political uncertainty that could affect the investment and financial provisions (CCC, 2013b). Following the expansion of the UK solar PV sector, and its advent inclusion in the renewable energy roadmap, a deployment potential range of between 7–20 GW is projected to be achieved by 2020 (DECC, 2013). An accelerated deployment of low-carbon and renewable energy technologies in the period to 2030 is set to be driven largely by the EMR's Feed-in Tariffs with Contracts for Difference (FiT CfD). This new electricity pricing regime illustrated in Table 2.1 is contractually agreed between the government and energy generators, and is established on the basis of the difference between an estimate of market price of electricity (the 'reference price') and an estimate of the long-term price needed to bring forward investment in a given technology (the 'strike price') (DECC, 2012b). The ability of the EMR programme to protect investors from electricity price volatility and investment risks could be catalytic in spurring investment in renewable and low-carbon energy technologies through the 2020s, and thus assisting in transforming the electricity generation infrastructure in order to align with the 2050 emission reduction target. This ambitious low-carbon energy future would require a total investment outlay of £100 billion up to 2020, followed by an additional £90 billion required to build the low-carbon electricity infrastructure through the 2020s (CCC, 2013a).

Table 2.1. Strike Prices (£/MWh) based on 2012 prices (DECC, 2013b).

Technology	2014/15	2015/16	2016/17	2017/18	2018/19
Dedicated Biomass (CHP)	125	125	125	125	125
Hydroelectricity	100	100	100	100	100
Onshore Wind	95	95	95	90	90
Offshore Wind	155	155	150	140	140
Large Scale solar PV	120	120	115	110	110

Energy from Waste (CHP)	80	80	80	80	80
Biomass Conversion	105	105	105	105	105
Wave	305	305	305	305	305
Tidal Stream	305	305	305	305	305

The allocation of CfD for nuclear and CCS projects is set to be negotiated as per individual project. This approach was demonstrated in the approval of an agreement between the EDF Group and the UK Government to build Hinkley Point C at a ‘strike price’ of £92.50/MWh over a 35 year period (DECC, 2014b). While the CfD could be one of the key drivers in delivering the ‘first of a kind’ fleet of new nuclear power plants in the UK, there is growing uncertainty over the delivery timeline and targets planned for 2030. Considering the UK government’s decision to cancel funding for CCS technology, the role of new nuclear plants in decarbonising the electricity infrastructure is vitally important. However, the current experiences with the new European Pressurised Reactors (EPR) in Europe (Flamanville and Olkiluoto), the same generic design earmarked for the UK have been characterised by delays amounting to several years behind schedule with a total of €5.1 billion (77 %) over budget (National Audit Office, 2012). While lessons can be learnt from these experience in Europe, the policy framework needs to have contingent measures in place to mitigate challenges that might humper the delivery of new nuclear power projects on schedule.

2.3.2 Dimensions of UK security of electricity supply

Energy security has been described as a multidimensional and context dependent concept whose meaning evolves as circumstances change over time (Ang et al., 2015). A definition of energy security presented in a report by the Asia Pacific Energy Research Centre (APERC, 2007) identified three fundamental elements namely;

i. Physical security denoting availability and accessibility of energy supply sources.

ii. Economic energy security representing the affordability of resource acquisition and energy infrastructure development.

iii. Environmental sustainability that prioritises the development and use of resources in a sustainable way.

The IEA defined energy security as an uninterrupted availability of energy sources at an affordable price (IEA, 2014a). The energy security paradigm is widely associated with a spectrum of threats and risks that impact on the energy system. The sources of threats/risks to the energy system can take the form of technical, human and natural (Winzer, 2012). In contrast, a study by Hughes (2012) on the concept of security of supply used availability, affordability and acceptability as the key indicators that could be used to conceptualise the premise of energy security. Based on this characterisation framework of the energy security paradigms (APERC, 2007; Winzer, 2012; Hughes, 2012) availability and accessibility are associated with human and natural risks while affordability and acceptability elements are identified with economic and environmental impacts of energy. The components or facets of security of supply changes in synchrony to advances in energy supply technologies as well to policies oriented towards climate change and sustainability. A study by Ang et al. (2015) identified seven major themes or dimensions of security of supply from definitions derived from a wide range of publications, namely energy availability, infrastructure, energy prices, societal effects, environmental, governance, and energy efficiency. Collectively, these indicators can be used to explore the vulnerability of the economy to the energy supply risk and its resource diversification in the context of fuel portfolios, political risks of acquisition and import dependencies (APERC, 2007).

In the context of the UK energy system, security of energy supply challenges have been focused exclusively on the potential exposure to vulnerabilities emanating from the imminent closure of aging generating infrastructure, increased fuel import dependency as well as intermittency of variable renewable resources. The new direction of the UK energy policy (DECC, 2015a) seeks to ameliorate these threats by proposing to build more new gas and nuclear energy plants. However, under the prevailing unprofitable investment and operational environment for gas generation plants, the UK government faces the challenge of incentivising the industry in order to achieve the new gas capacity required to drive the new energy policy. As the impetus to decarbonise the electricity sector gains momentum in the period to 2030, the level of variable renewable energy resource deployment, particularly wind and solar could further expose the energy system to potential security of supply threats. The security of supply issues stemming from gas availability have been widely linked to equipment and infrastructural failures and extreme weather conditions as opposed to politically motivated or other deliberate external interventions (Skea et al., 2012).

While the impact of these unforeseen incidences on the major national gas supply infrastructures pose a threat to security of supply, the prevailing depressed gas markets are likely to cause an even greater threat to the system's ability to meet peak electricity demand. The unfavourable investment climate for new and old gas plants, coupled with the diminished running hours following the increase in renewable technology deployment could limit gas generation plant deployment capacities, and thus depriving the electricity generation supply system with one of the most reliable and flexible baseload generation sources. These threats to the rollout of more gas plants particularly in the period to 2030 are further exacerbated by the uncertain policy landscape especially on the future of the carbon floor price and the level of incentives likely to be introduced to drive investment in new gas plants.

Nuclear power generation in the UK energy security discourse is viewed not only as a key determinant for the future of the country's economy and society but also as a 'clean' technology that provides a response to increasingly pressing needs for energy independence (Teräväinen et al., 2011). Nuclear power generation is strategically important in meeting the UK government's decarbonisation ambitions along with offshore wind and CCS. Its role in contributing towards alleviating global warming and energy security is indispensable, particularly at a time when a potential energy crunch is highly expected owing to the imminent plant closures and increased build-up of intermittent generation through the 2020s. Uncertainties over the investment climate for new-generation EPR, a preferred design for the UK future nuclear energy fleet, and the delivery prospects for the projected deployment capacity to 2030 have combined to increase the security of supply vulnerability from nuclear.

Nuclear power plants have higher capital cost compared to fossil fuel plants due to the use of special materials and sophisticated safety features to enhance the safety of the plants. The new-build nuclear energy plant first-of-a-kind (FOAK)'s overnight investment costs are estimated to range from US$4500 to US$6750/kW compared respectively to US$1600/kW and US$1050/kW for new-build coal and gas CCGT plants, (Mott MacDonald, 2010). The affordability of new advanced nuclear plants is likely to be hampered by additional safety measures after the accident at Fukushima, higher interest rates and the burden of more interest rates during long periods of construction (Hayashi & Hughes, 2013). The nuclear industry has projected about 16 GW capacity of new nuclear power plants to be deployed by 2030 (HM Government, 2013), but as of now, no investment decision has yet been finalised for the first plant at Hinkley Point C. The deployment capacity and timeline for the new fleet of UK nuclear power plants scheduled for 2030 is highly unlikely due to the high capital costs, prolonged construction periods resulting from regulatory delays and design requirements, leading to even higher construction costs.

The security of supply analogue advanced in this thesis focuses on the supply vulnerabilities resulting from the failure of the existing policy to create an enabling investment climate to promote the penetration of new gas plants in the generation mix. The scenario options that assess the impact of gas supply threats to energy security are developed based on the assumption that the investment climate for gas will remain unprofitable throughout the period to 2030. This supposition is drawn from the understanding that the capacity market prices likely to be achieved at the capacity market auctions through the 2020s will be unfavourable for gas generation. As a result, the anticipated rollout of new gas plants will not happen and worse still, some of the older plants could be mothballed or even decommissioned under these constrained economic conditions. The uncertainty over the future contribution of gas generation plants to meeting electricity demand and in providing back-up to intermittent renewable power sources will be explored through scenario assessment in Chapter 4 of this thesis. While gas generation is expected to have a limited role under system decarbonisation, its role in providing back-up to intermittent generation cannot be underestimated, and hence the need to build more gas plants in the new energy policy 'reset'. Another set of scenarios will seek to explore the security of supply challenges resulting from the failure by the government, investment community and the nuclear industry to develop and commission more than one nuclear power plant project by 2030. Scenarios are developed around these energy security threats in order to contextualise the wider policy implications, particularly in the light of the sectoral decarbonisation aspiration for 2030. The scenarios will also explore the potential role of coal plants with extended operational life in the generation mix and the implications on the security of supply and electricity sector decarbonisation objectives.

2.3.3 Intermittent generation: system and policy adaptability

The increased government support for the deployment of renewable energy technologies in the UK generation mix is to some extent driven by the need to contribute towards meeting the EU proposed 40 % GHG emissions and the 27 % renewable energy targets by 2030 (Erbach, 2014) and the UK’s 80 % GHG emission reduction by 2050. The high penetration of intermittent renewable energy generation, that is, generation that exhibit uncontrolled increases or decreases in output (POST, 2014) poses immense challenges to the maintenance of flexibility and reliability in the electricity supply system. Wind, solar, wave and tidal are the main variable renewable energy sources within the UK generation mix that are characterised by large-scale variations in the amount of electricity output they can provide at any given time. An increase in the volume of intermittent renewable energy source deployment is anticipated within the UK generation mix in the period to 2020, 2030 and 2050, principally due to the 30 % electricity output expected from renewable sources (DECC, 2012d) and the policy ambition seeking to increasingly decarbonise electricity generation infrastructure in these periods, respectively.

The prospects of delivering the capacity estimates of 18 GW offshore wind, 13 GW onshore wind (DECC, 2011c) and 20 GW solar (DECC, 2013c) by 2020, could greatly impact on the costs of balancing the system as well as affect the system’s capacity to achieve a measure of reliability during peak energy demand periods. System reliability expresses the capacity of the electricity generation infrastructure to supply electricity to consumers at all times. For such systems to be deemed reliable, it has to have sufficient generation infrastructure to supply and meet electricity demand, with a high degree of flexibility to allow a quick and controlled response to predicted and unpredicted fluctuations in demand (POST, 2014). The impact of weather conditions on the power output from intermittent renewable energy sources has a potential to compromise on their contribution to the system reliability, and hence the need for standby/reserve generation from fossil-fired generation, nuclear or storage to maintain flexibility and continuous system balance.

Capacity credit or reliable capacity is a measure (percentage) of the contribution of intermittent sources to peak demand (Skea et al., 2007). Electricity systems are usually operated with an installed capacity greater than the peak demand (system margin), however, a high penetration of intermittent generation capacity in the mix could require a larger capacity margin to achieve a satisfactory level of system reliability. The capacity credit of intermittent sources is smaller than their installed capacity as illustrated in the example in Table 2.2. In that sense, a generation mix with a high proportion of intermittent sources would require adequate reserves (capacity margin) to mitigate fluctuations in demand and supply. In the context of the 2013 UK generation mix portrayed in Table 2.2, it is noticeable that out of the 11 GW installed wind capacity, a range of between 0.77-2.75 GW capacity could contribute to the 52 GW peak demand for the 2013 winter period. Therefore, it can be concluded that increasing the diversity of intermittent supply source could contribute more to system reliability than the sum of the individual reliable capacities.

Table 2.2. Contribution of technologies to system reliability at peak demand (POST, 2014).

Technology	Reliable capacity as % of maximum capacity	2013 UK maximum capacity, GW
Wind	7-25	11
Solar	0	2.7
Hydro	79-92	1.7
Tidal	35	<0.001
Wave	35	<0.001
Fossil-fuelled and Nuclear	77-95	78

As the UK electricity generation infrastructure decarbonises, an increased portfolio of intermittent generation could dominate the system. The increase in low-carbon energy technologies in the system could hugely displace unabated conventional fossil fuel generation in the electricity supply mix, and thus impacting on the security of supply. Accommodating a large proportion of variable renewable energy capacity on the grid would require retaining adequate reserves of conventional plants that are likely to be run at very low capacity factors, and thus impacting on their economics and efficiency. Depending on the level of intermittent renewable penetration, the increased use of flexible conventional plants could impact on the amount of carbon emissions produced, and thus impacting on the emission targets set.

2.3.4 UK shale gas development: Policy implications

The shale gas resource potential across the UK has speculatively been focused around the Bowland-Hodder Unit and Midland Valley of Scotland as illustrated in Figure 2.6. These two regions are currently estimated to be endowed with 1409.3 tcf in total (DECC, 2014c; Andrews, 2013). Using a 10 % recovery rate, this resource estimate could potentially supply up to 140.9 tcf of recoverable shale gas, that is, 50 times the UK's 2.8 tcf annual domestic and industrial gas consumption (McAlinden, 2013). However, there is great uncertainty as to how much of this resource is commercially recoverable, and the timeline to which full scale production could commence. The favourable industrial, regulatory, geology and cultural factors which made the US shale gas revolution a reality do not prevail in the UK. Taking these variations into perspective, there is consensus that significant commercial production of shale gas in Europe is unlikely until the 2020s and possibly into the 2030s (Bradshaw & Watson, 2014) due to the physical and infrastructural constraints.

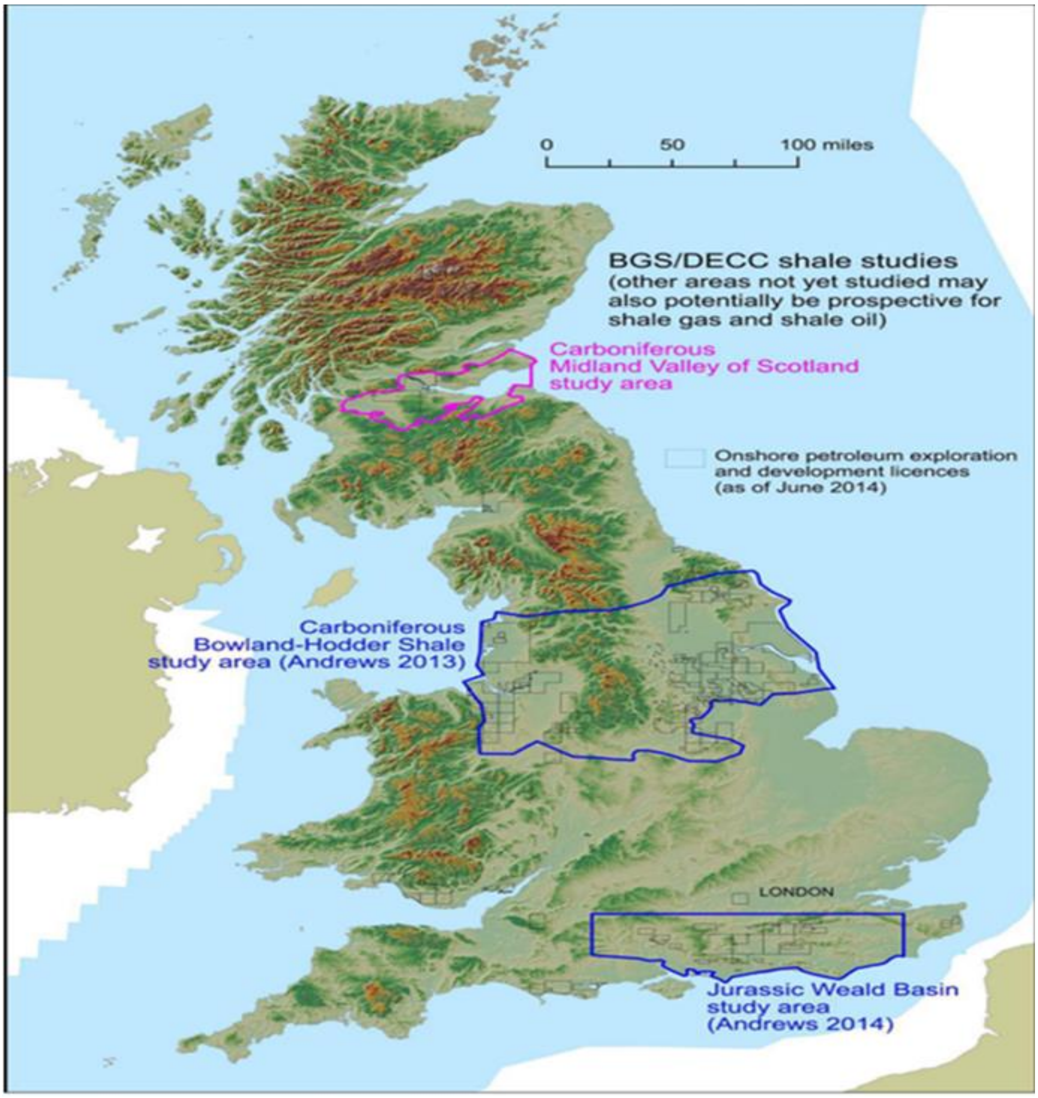

Figure 2.6. Potential shale gas resource areas in the UK (Andrews, 2013).

While the debate on the economics, recoverability and desirability of the shale gas resource development for the UK energy context rages on, the UK government is currently putting in place a regulatory framework that could promote a safe and environmentally sound exploration that could determine its potential. The UK government's motivation to remain steadfast in creating an enabling environment for shale gas development in the midst of fierce and unrelenting public opposition is borne out of the believe that it has the potential to provide the UK with greater energy security, growth and jobs (DECC, 2015i). Putting the shale gas potential into context, a study by Pöyry (2011) suggests that the upper limit quantity of gas in the current UK estimates has a market value of £40 billion at a gas price of 70p/therm. It is further argued that the volume of shale gas likely to be extracted could provide in access of 10 % of the UK's natural gas for a period of 15 years

(Pöyry 2011). Therefore, it is no surprise that the UK government has remained committed to developing this resources in the midst of a host of challenges ranging from fiscal, planning and environmental which militate against its successful development.

The contribution of shale gas to the UK economy and subsequently in addressing energy-related challenges in the UK is still unknown. However, its extraction and use has raised concerns over its sustainability both on human health and the environment. Whilst the full life-cycle impact and the risks associated with shale gas extraction remain unresolved in the US, questions continue to be asked about the adequacy and robustness of the current UK regulatory framework to mitigate potential environmental impacts. The injection of fracturing additives underground for hydraulic fracturing purposes are feared to have a potential impact of contaminating land and water resources during shale gas extraction processes. Also, it is argued that potentially, there could be significant levels of intrusion onto the landscape coupled with an increase in noise and traffic movements resulting from shale gas extraction. Moreover, these social and environmental disruptions could be more pronounced during the construction phase of the shale gas development process. While some of these impacts are likely to be localised, with some almost difficult to alleviate, it is anticipated that the social and environmental impacts could be managed through regulation. Seismic activities in the UK around the Blackpool region in 2011 have been linked with hydraulic fracturing activities undertaken by Cuadrilla Resources (Broderick et al., 2011).

Contrary to reports that the development of shale gas in the UK could result in the fall in gas prices, the modelling by Pöyry (2011) suggests that gas prices in the UK and Europe are likely to go up rather than down. It is also believed that prospects of domestic shale gas development in the UK may not by any means restore self-sufficiency in gas supplies. However, in the event that significant volume of unconventional gas is produced, there is a likelihood that shale gas production could reduce import gas dependency as well as replace the dwindling North Sea gas reserves. While this domestic resource could be significant in addressing security of supply challenges, its role in electricity generation could be limited unless used in conjunction with CCS technologies which are yet to be proven outside Canada. In any case, the unceremonious cancellation of CCS funding by the UK government could potentially imply the absence of CCS technology in the generation mix by the time shale gas production gets under way. This development could further limit the amount of shale gas that could be used in unabated gas plants due to stringent emissions targets commensurate with the aspirations to decarbonise the electricity supply sector in the period to 2030 and beyond.

Whilst the decarbonisation of the electricity supply system remains a cost-effective route to achieving both domestic and regional climate change targets, it is argued that shale gas should be promoted as a transitional fuel which offers security of supply and low-carbon electricity when burned in efficient CCGT plants. However, in the event of a potential drop in gas prices triggered principally by the increased exploitation of UK and global shale gas reserves, gas-fired generation could substitute high cost renewables, and thus impacting on the decarbonisation objectives (Broderick et al., 2011). This development could militate against the UK's 2 ^{o}C commitments on global climate change as well as on its Low Carbon Transition Plan.

As the countdown to the 2030 decarbonisation milestone draws near for the electricity supply infrastructure, the prospective role of unabated shale gas becomes very complex. This is mainly because the CCC envisages unabated gas generation plants running below 10 % load factors, mainly for system balancing in the period to 2030 (CCC, 2014). Given this limited role of unabated gas generation in this period and beyond, the contribution of shale gas to the mix could be insignificant with little economic prospects to utility operators. As a result of this constrained gas operation regime, investment in new gas generation infrastructure could potentially be compromised, and thus leaving the existing capacity either to retrofit CCS, fall back into a peaking role or decommission if the alternative options are uneconomic (CCC, 2010). Thus, a transition to a low-carbon electricity future could literately shut the door for shale gas development, unless the UK government decides to make another U-turn on its policy on CCS which could lead to the resumption in its development and eventual commercialisation.

2.4 UK electricity sector transition pathways to 2050

A scenario assessment approach has been adopted in this thesis to explore how the UK electricity supply system could move to low-carbon by 2050. The electricity generating infrastructure is predominantly built on fossil fuels, and hence the need for the system to evolve over the next thirty-five years or so to contribute towards the 80 % GHG emission reduction target by 2050 relative to 1990 levels. The evolution of the electricity supply sector through to 2050 requires radical changes in the current technology distribution within the generation mix to be achieved while maintaining security of supply, environmental and social sustainability objectives. The accelerated technology deployment through the 2020s in the form of CCS, nuclear, wind, solar and marine is likely to characterise the generation mix during this period as system decarbonisation by 2030 becomes an immediate policy milestone. The emphasis to have the electricity supply system decarbonised by 2030 is borne out of the goal to achieve a cost-effective transition to 2050.

While a low-carbon electricity generation infrastructure is catalytic for system-wide decarbonisation, the system transition to 2050 is fraught with uncertainty. There are questions being raised concerning the resoluteness of the current energy policy and its capacity to attract and promote investment and technological innovation that could foster the kind of low-carbon energy transition envisaged by the Climate Change Act. The main features that will define the character of the UK electricity transition to 2050 revolve around technology availability and timeline for deployment, technology cost reductions and the speed at which the policy mechanisms can facilitate these developments. With the current direction of the UK energy policy hard to predict, the nature and the path that the electricity generation sector transition could follow is a matter of speculation. Therefore, it is through scenario assessments that the full extent of the dynamics that impact on the UK electricity supply sector can fully be conceptualised in the context of system decarbonisation.

2.4.1 Transition theories: Conceptualising low-carbon energy transitions

A transition as described by Geels (2005) denotes a shift from one sociotechnical system to another. Various analytical approaches derived from sustainability studies have been adopted and applied to energy systems in an attempt to gain insight into the processes that influence the emergence and development of low-carbon transitions. These analytical frameworks, namely multi-level perspective (MLP), co-evolutionary framework and innovative systems theory have featured in many studies seeking to explain transitions in society (Foxon and Hammond, 2010). While these frameworks offer different perspectives to transition development, this thesis devotes attention on the MLP and co-evolutionary theories and uses their characterisation to analyse socio-technical scenarios that could enhanced understanding into the evolution of the UK electricity generation infrastructure to a low-carbon future.

2.4.2 The multi-level perspective

The MLP conceptualises transitions as nonlinear processes that results from the interplay of developments at niches, socio-technical regimes and exogenous socio-technical landscape analytical levels (Geels, 2011) as illustrated in Figure 2.7. The MLP on transitions recognises the interactions across niches, regimes and landscape processes which assist in informing organisations on strategic, tactical and operational governance activities (Smith & Stirling, 2008). The interaction at these three developmental levels assumes a nested hierarchy where regimes are embedded within landscapes and niches within regimes (Geels, 2002) as depicted in Figure 2.7. In this analytical framework, niches represents ‘protected spaces’ where radical innovation takes place and are usually insulated from the ‘normal’ selection in the regime (Geels, 2002).

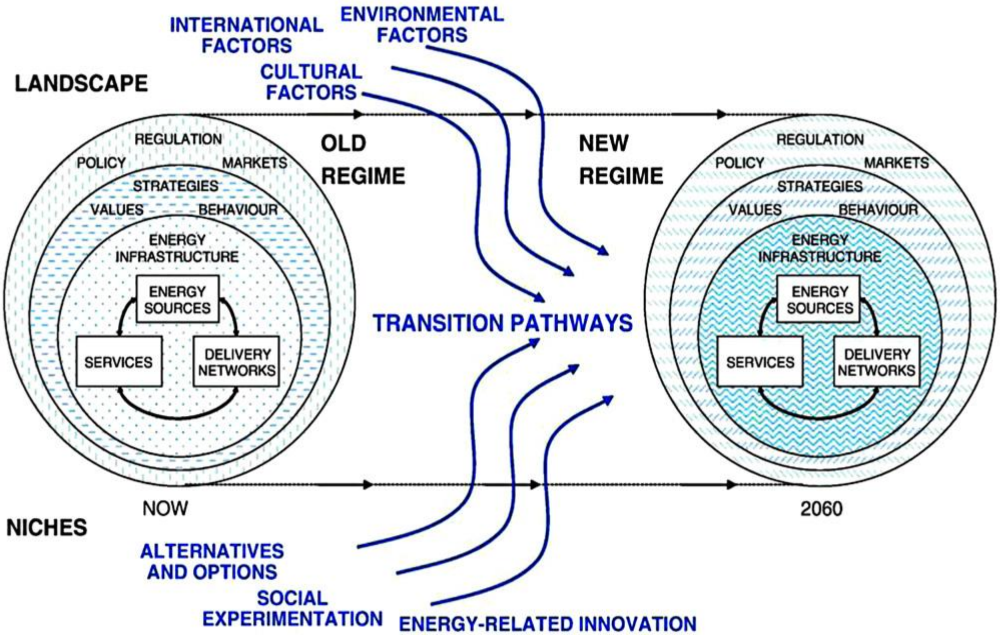

Figure 2.7. Sociotechnical attributes of a multi-level perspective (MLP) framework (Foxon et al., 2010).

The limited susceptibility to prevailing outside pressures allows innovation and other designs within niches to be nurtured and sustained as new ways of doing things are valued; learning is encouraged and imbedded in future development (Smith & Stirling, 2008). In transition development, niches play an important role as they act as centres for learning processes as well as for building social networks which support innovations. However, the capacity of niches to induce change to existing system ‘regimes’ is constrained due to entrenched structures ‘lock-in’ mechanisms which strive to maintain the integrity of systems. It is through mapping and representation of functions and structure processes over time that insights in the dynamics of innovation system is created and applied to energy systems in transition.

Socio-technical regimes are rules that enable and constrain activities within communities (Geels, 2002) and they represent ‘deep structures’ that account for the stability of an existing socio-technical system (Geels, 2011). This socio-technical system is composed of distinct semi-autonomous social groups whose sub-systems are interdependently linked (Geels, 2005) which allow them to co-evolve with each other and also with the external (environment) landscape. The continuity of these regimes and their ability to insulate themselves from outside influences is fostered by a set of rules or routines that coordinate the activities of the social groups, and thus allowing the groups and their sub-systems to be aligned to each other.

The rules and value systems that underpin socio-technical regimes create the 'lock-in' phenomenon, and thus allowing innovation to occur incrementally. Therefore, a regime is perceived to be interlinked at three dimensional levels; (i) a network of actors and social groups evolving over time; (ii) a set of formal and informal rules that coordinate and align activities of actors who produce and maintain the elements of a socio-technical system; and (iii) the material and technical elements (Geels, 2004). The development of stable regimes within a favourable landscape leads to the creation of a stronger alignment between different elements of the system in which it operates, thereby making the entire system path dependent/locked in (Raven & Verbong, 2009).

The sociotechnical landscape refers to aspects of the wider exogenous environment which influence socio-technical development (Geels, 2005). It represents the material context of society which, according to Geels (2002), constitutes the material and spatial arrangement of cities, factories and electricity infrastructures. Also, it extends to embrace entities such as demographical trends, political ideologies societal values and macro-economic patterns (Geels, 2011). Changes in landscape occurs slowly but with significant impacts on the levels below, even to the extent of rearranging the place of regimes and niches within the system (Lachman, 2013). While this transition framework is important in understanding the dynamics that impact organisations, institutions and cultures as examined in this thesis, it has been criticised for being rather complex and ambiguous. It has been argued that "it uses metaphors and imprecise concepts, with the danger of creating ambiguity and being able to categorise phenomena too easily since the concepts have vague boundaries" (Lachman, 2013: 271).

2.4.3 The co-evolutionary framework

Co-evolution principles are drawn from biological evolution whose origins stem from the Darwinian hypothesis which argues that population entities evolve if they follow the processes of variation, inheritance and selection (Kallis & Norgaard, 2010). Outside the biological sphere, an evolutionary framework described in Foxon (2011) suggests that key events in transition may occur through technological changes, forming of institutions, revision to business strategies or changes to use practices as highlighted in Figure 2.8. These systems co-evolve if they have a causal influence on each other's evolution (Kallis, 2007). The co-evolutionary thinking recognises that each socio-technical system evolves under its own dynamics but the causal effect from other entities or systems affect the pattern of change within the system as they interact. This implies that any transformation within or between entities cannot happen without triggering or being triggered by the influences of other systems undergoing separate changes of their own. Based on this observation, Norgaard (1994) concluded that the evolution of entities is influenced by the relationships between entities, implying that everything evolves in response to everything else within the system. The causal influences that creates interaction between technological and institutional systems provide a solid schema through which the forces and influence that promote transitions towards more sustainable and low-carbon future could be examined. Therefore, the co-evolutionary framework is useful for undertaking analysis of dynamic processes (the evolution of relationships and causal interactions) that contribute at multiple levels to a transition to a low-carbon economy (Foxon, 2011).

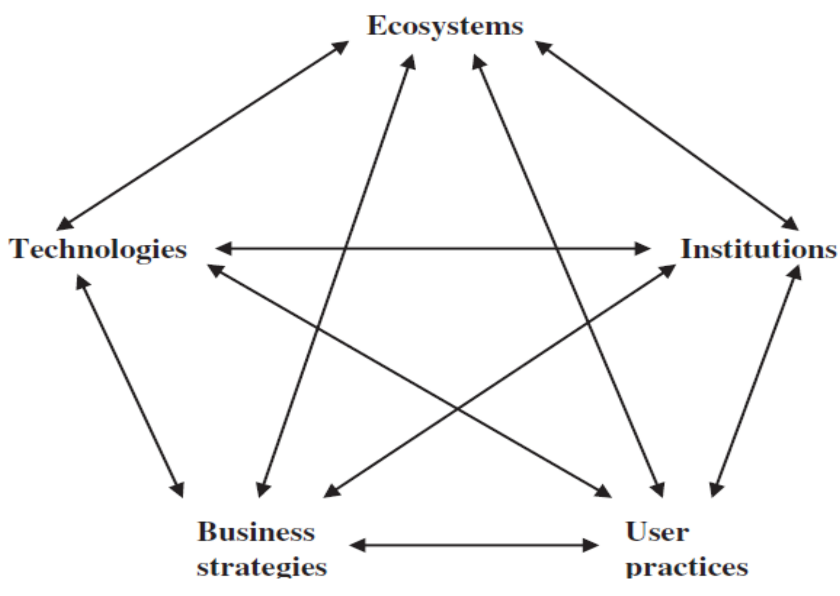

Figure 2.8 The Co-evolutionary framework (Foxon, 2011).

The mutual causal influences between systems and their impacts on system dynamics have huge implications on characterising energy systems as they evolve towards low-carbon futures. The path-dependent nature of co-evolutionary change in systems has been known to induce a historical lock-in effect, particularly in technological and institutional entities (Unruh, 2000; Unruh, 2002; Unruh & Carrillo-Hermosilla, 2006), and thus increasing barriers to the development and uptake of low-carbon technologies. The lock-in phenomenon is deeply entrenched in global economies particularly in the power sector where fossil-fuelled electricity generation remains and will continue to dominate electricity supply systems. Insights from the co-evolutionary framework have been used in this thesis to analyse the causal influences of technologies and institutions in defining the evolution of the UK electricity generation infrastructure to a low-carbon future.

2.4.4 Implications of the MLP and Co-evolutionary frameworks on the UK low-carbon electricity infrastructure development

The application of ideas and concepts derived from these frameworks are important in enhancing an in-depth understanding of the dynamic interaction between constituencies and their impact on the transition of energy systems to low-carbon futures. The existence of interactive structures within systems allow for the adoption of an integrated approach to developing sustainable transitions to a low-carbon futures. This is enhanced by understanding the functions, interdependences and co-evolutionary tendencies which exist within sociotechnical systems. The techno-institutional lock-in phenomenon expounded by Unruh (2002) has far reaching implications to the UK electricity supply infrastructure which is predominantly carbon based.

Building on these frameworks for analysing sociotechnical change for a transition to a low-carbon economy, policy approaches would need to be tailored to overcome barriers created by techno-institutional lock-in. This is typically relevant in the context of the current UK electricity regime where a transition to low-carbon electricity generation future faces the challenge of a strong historical lock-in resulting from established technological, organisational, industrial, social and institutional evolutionary processes (Kallis, 2007; Unruh, 2002). The MLP and co-evolutionary concepts have characterised system change as structured, uncertain, path-dependent and incremental. Thus, the adoption of this sociotechnical analysis framework in low-carbon policy development could assist in overcoming system lock-in, and thus assisting in transforming the electricity generation infrastructure to a low-carbon future.

2.5 The low-carbon future scenarios for the UK

Scenario methodologies have been applied in a wide range of settings with the aim of improving the quality of decisions made on future developments. In the context of the UK low-carbon energy futures, scenario assessments have sought to capture decarbonisation trajectories in line with achieving the 80% GHG emissions by 2050 against 1990 levels, as well as the decarbonisation of the electricity sector by 2030 (HM Government, 2008; CCC, 2010). Low-carbon scenario building is usually fraught with uncertainties owing to the long time frames involved, technology speculations surrounding decarbonisation ambitions, as well as the difficulty of forecasting future impacts of decarbonisation on social change (Hughes & Strachan, 2010). As instruments of change used for strategic planning, scenario assessments in energy systems are largely centred on technically plausible futures and their likely impacts on costs and benefits based on modelling approaches that assume a high level of economic rationality of actors (Foxon et al., 2010).

Scenario analysis for the UK low-carbon futures have predominately taken a technical plausibility perspective driven by the need to demonstrate the technical feasibility of the energy system to meet energy demands and carbon reduction targets (Hughes & Strachan, 2010). Different modelling technics have been adopted to generate scenarios to inform the current UK policy. Examples of UK based techno-economic scenarios that explore the transition of the current carbon intensive energy system, to one that achieves the Government's 80% carbon reduction target by 2050, are briefly discussed in the following subsections. Technology development and deployment up to 2030 is crucially important in facilitating a cost-effective achievement of the 2050 decarbonisation target. Scenarios outlined in the following subsections show the projected generation portfolio outlay to 2030 and 3050, from different modelling communities with a view to highlighting the penetration of the low-carbon energy technologies required to decarbonise the electricity supply sector.

2.5.1 UKERC Energy 2050 Scenarios

The UK Energy 2050 project, steered by the UK Energy Research Centre (UKERC), developed low-carbon scenarios dedicated towards exploring the implications of adopting an array of low-carbon emission trajectories ranging from 40-90 % to the UK energy system by 2050. The low-carbon trajectory pathways were developed using the MARKAL, a technology-rich optimisation model fully calibrated to data within 1 % of the actual resource supplies, energy consumption, electricity output, installed technology capacity and CO_2 emissions (Anandarajah et al., 2009; Kannan, 2011). Rather than focusing too much upon an end-point in 2050, the MARKAL modelling framework tracks the development and deployment of emerging technologies such as CCS and mitigation of electricity intermittence from renewable energy resources though its MARKAL Elastic Demand (MED) model function (Anandarajah et al., 2009).

Scenarios depicted in Table 2.3 illustrate the outputs from the MARKAL model developed to achieve both the 2020 and 2050 CO_2 emission reduction levels of 15-32 % and 40-90 %, respectively. Based on the scenarios portrayed in Table 2.3, it is notable that the faint-heart (CFH) does not align with the UK government's carbon emission reduction commitments. Its emission performance is about half the legislated target set for 2050. On the other hand, the low-carbon pathways presented in Table 2.3 achieve 26 to 32 % and 80 to 90 % emission reduction relative to the 1990 levels in 2020 and 2050, respectively, which is in conformity to the decarbonisation blueprint espoused by the Climate Change Act. It is of great concern that the challenges currently affecting the UK energy policy development could render the attainment of the technology diversity in the CLC, CAM and CSAM scenarios almost impossible. The stall in CCS and new nuclear energy plant development and the resurgence of a policy promoting gas generation could potentially drift the UK emission reduction commitments towards the CFH scenario.

Table 2.3. UKERC Energy 2050 scenarios (Ekins et al., 2013).

Scenario	Scenario name	Annual targets % reduction from 1990 level	Cumulative Emission $GtCO_2$ (2000-2050)	2050 emissions $MtCO_2$
REF	Base Reference	-	30.03	583
CFH	Faint-heart	15 % by 2020 40 % by 2050	25.67	355

CLC	Low Carbon	26 % by 2020 80 % by 2050	22.46	237
CAM	Ambition (‘low-carbon core’)	26 % by 2020 80 % by 2050	20.39	118
CSAM	Super Ambition	32 % by 2020 90 % by 2050	17.98	59

The level of decarbonisation achieved in the scenarios presented in Table 2.3 is reflective of the electricity generation technology penetration projected in Figure 2.9 for each scenario. The increased deployment of low-carbon and renewable energy technologies from the period 2035 to 2050 accounts for a significant reduction in emissions for the CLC, CAM and CSAM scenarios. These low-carbon pathways have no unabated coal generation in their technology portfolio, serve for the unabated gas which is significantly reduced in 2035. Unabated gas generation is completely absent from the mix by 2050 in all the low-carbon energy scenarios. The deep cut in emissions achieved by these three low-carbon energy pathways (see Table 2.3) is a result of the dominance of CCS and nuclear in the CLC and CAM scenarios while nuclear and offshore wind, which account for over two thirds of the generation capacity in CSAM are influential in driving the transition to the 2050 emission reduction target. The 2035 and 2050 low-carbon electricity supply outlook presented by the scenarios in Figure 2.9 remains uncertain, particularly over the dominant player in any optimal technology portfolio of CCS vs nuclear vs offshore wind due to the close marginal cost and uncertainties in these technology classes (Ekins et al., 2013). The development of a stable and consistent UK energy policy, one that is shaped and driven by the fundamental principles of the Climate Change Act, could assist in defining the low-carbon technology landscape presented in Figure 2.9.

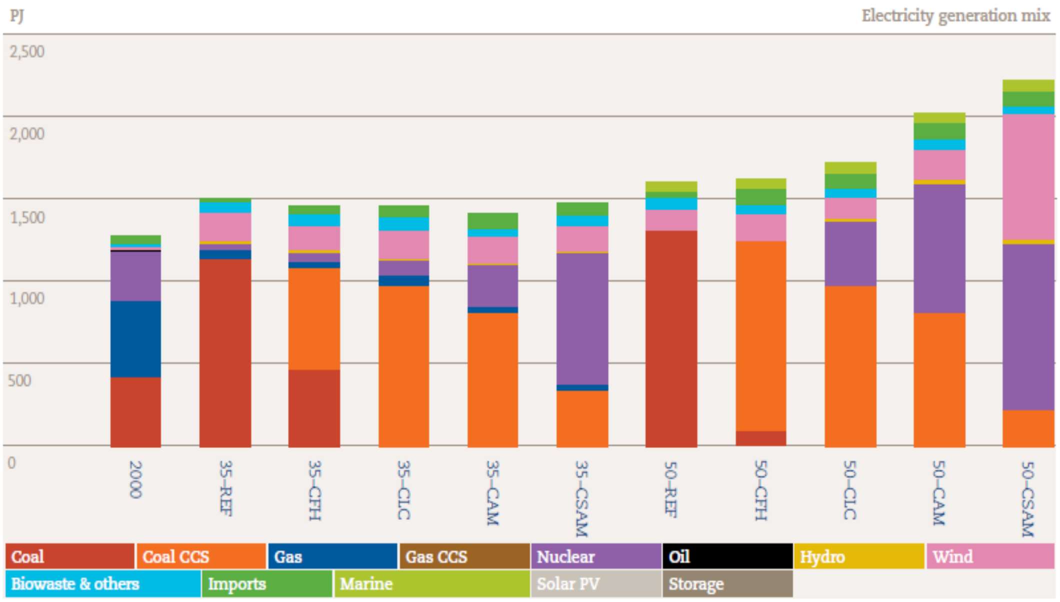

Figure 2.9. Energy generation mix in 2035 and 2050 for the Energy 2050 scenarios (Ekins et al., 2013).

2.5.2 FESA energy system modelling

The future energy scenario assessment (FESA) was used by the 'technical elaboration working group' of the Transition Pathways research consortium to develop three Transition Pathways: Market Rules, a market-led, Central Co-ordination, a government-led and Thousand Flowers, a civil society-led pathways (Foxon, 2013). The transition pathway scenario development is based on the multi-level perspective framework (outlined in Section 2.4.2) and its ethos is to establish how a range of actor groups, including policymakers, incumbent market firms and civil society can shape transition pathways to low-carbon futures (Foxon, 2013).

Based on the logic of each pathway, the electricity infrastructure requirements were modelled using FESA model to reflect on the energy service demand and the generation mixes required for each pathway. The technologies deployed to meet demand for each of the three pathways are similar, however, the level of technology penetration is influenced by the governing logic for each pathway. The installed generation mix from FESA model for each of the pathways is illustrated in Table 2.4. Although these pathways have become out of date in terms of reflecting the current developments within the electricity supply sector, Barnacle et al. (2013) maintain that the pathway narrative still creates a plausible energy future for the UK. The scenarios developed from FESA were employed in this thesis because they provide an optimal generation mix that achieves a near zero carbon dioxide emission reduction by 2050 as part of the legally binding target set to achieve 80 % reduction in GHG emissions relative to 1990 levels.

Table 2.4. The generation mix for the Transition Pathway Scenarios (Barnacle et al., 2013).

	Market rules			Central co-ordination			Thousand flowers		
Generators	2020	2035	2050	2020	2035	2050	2020	2035	2050
Coal	16.3	0.0	0.0	16.4	0.0	0.0	16.4	0.0	0.0
Coal CCS	2.3	14.9	22.0	2.0	6.0	10.0	2.0	7.5	7.5
Gas CCGT	34.8	25.7	14.1	29.0	17.7	6.6	29.0	15.7	0.0
Gas CCS	0.0	16.0	22.0	0.0	17.0	20.3	0.0	11.6	14.2
Gas OCGT	1.1	0.3	0.0	2.3	0.4	0.0	1.0	0.3	0.0
Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	10.7	17.2	25.8	12.2	22.1	30.0	5.4	5.4	5.4
CHP	9.0	9.0	8.9	9.3	9.4	9.6	24.4	46.6	52.5
Onshore wind	9.4	16.4	22.5	10.2	15.4	20.5	10.2	15.4	20.5
Offshore wind	7.0	18.7	30.2	8.4	12.6	16.8	4.9	6.3	8.4
Hydro	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Biomass	1.9	1.5	1.5	1.7	1.5	1.5	1.7	1.5	1.5
Wave	0.6	2.1	2.1	0.6	2.1	2.1	00.6	2.1	2.1
Tidal	0.9	11.6	11.6	0.4	8.9	8.9	0.4	8.9	8.9
Solar	0.1	0.2	0.2	1.0	2.1	4.1	4.1	8.1	16.2
Pump storage	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Interconnector	4.3	6.1	6.1	4.3	6.8	6.8	4.3	6.8	6.8

The government's low-carbon futures were constructed using MARKAL and Energy System Modelling Environment (ESME), the cost-optimisation models employed to assess the level of ambition required to develop plausible low-carbon energy technology based scenarios to achieve the 2050 decarbonisation target. Central to these '2050 futures' is the Higher Renewables, more energy efficiency, Higher CCS, more bioenergy and the Higher Nuclear, less energy efficiency, produced by the DECC's 2050 Calculator (DECC, 2010). Since the DECC 2050 Calculator is a non-optimisation model, and assumes no specific policy aspirations beyond 2020, the three low-carbon futures are benchmarked against the core-MARKAL pathway (HM Government, 2011) for comparison purposes. The electricity supply generation outlook in 2030 for the four DECC 2050 Calculator futures is shown in Figure 2.10, highlighting to a degree, the low-carbon landscape envisaged by the UK government.

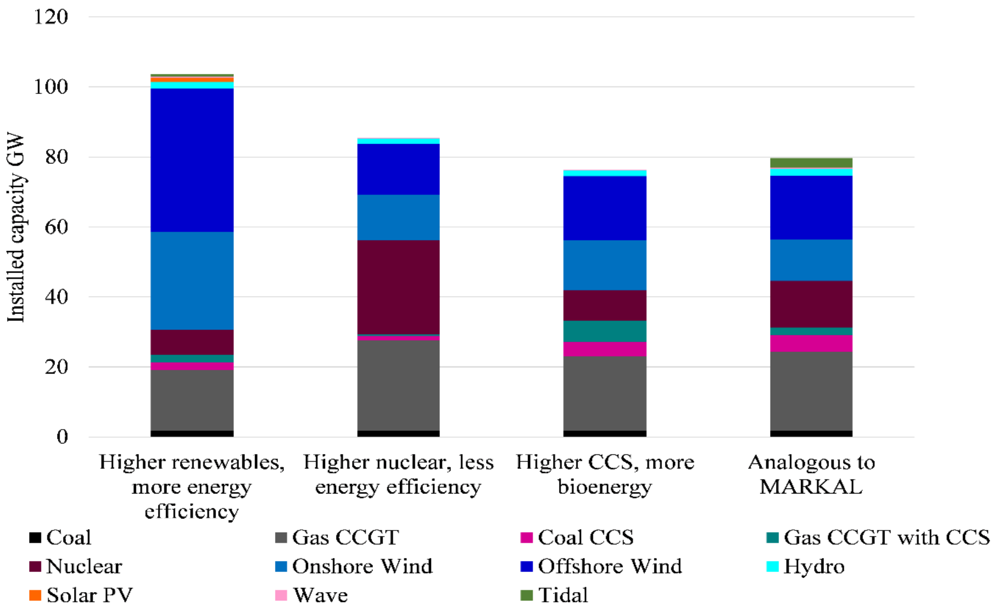

Figure 2.10. The 2030 installed generation capacity for the DECC 2050 'futures' (DECC, 2010).

The potential impact on security of supply induced by the increased penetration of intermittent generation from wind is ameliorated by an abundant supply of baseload capacity from nuclear, CCS and unabated gas plants as illustrated in Figure 2.10. These scenarios capture the outlook of the electricity generation infrastructure landscape as portrayed under different technology development and deployment framings. The low-carbon pathways portrayed in Figure 2.10 give insight into the government's ambitions and possible technology decarbonisation options that could be adopted to keep the UK economy on the path to achieving 80 % emission target by 2050. Such policy oriented pathways are critically important for investigation in this thesis as they increase the resource base for analysing the appropriateness and flexibility of current policies that are designed to achieve the decarbonisation ambitions set by the UK government.

As a body legally enacted to advise the government on energy and climate change issues, the CCC has outlined scenario alternatives required to decarbonise the electricity generation infrastructure by 2030 in line with the carbon budget plans (HM Government, 2008). Taking into account the inherent uncertainty surrounding the development of emerging technologies, cost reductions and technology development and the current project pipelines, the CCC presented scenario ambitions involving a portfolio of low-carbon energy technologies built around either nuclear, renewables or CCS shown in Figure 2.11 with the scope to achieve a 50 gCO_2/kWh grid intensity by 2030 (CCC, 2013b). These scenarios provide potential decarbonisation options assuming that each of the main options for low-carbon electricity supply technologies prove to be timely, technically and economically viable for deployment through the 2020s.

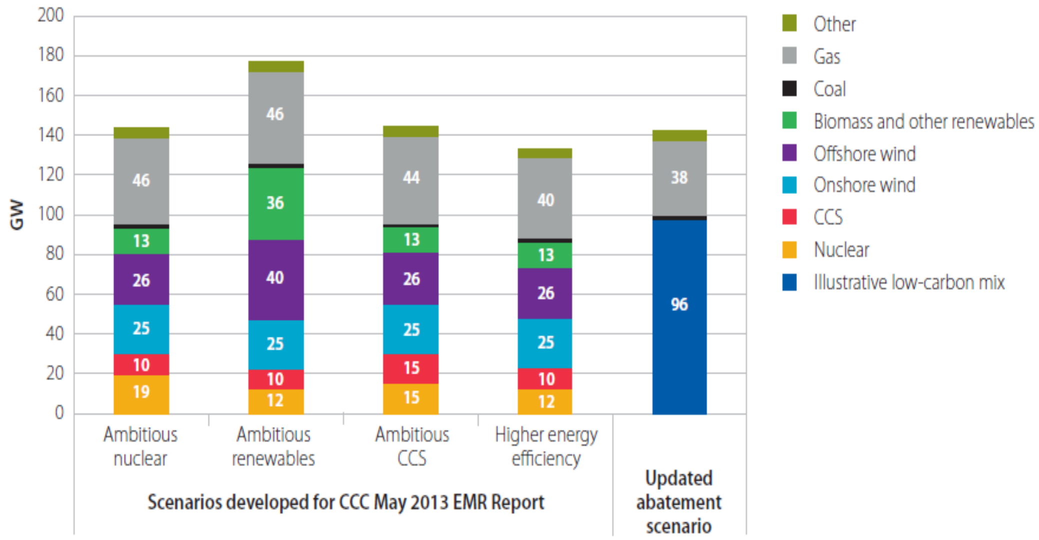

Figure 2.11. Power sector scenarios reaching 50 gCO_2/kWh by 2030 (CCC, 2013b).

The ambitious technology penetration projected in each of the scenarios is dependent on the success of the EMR to drive investment in low-carbon energy technologies. Despite the current favourable market conditions for coal, its role in the generation mix in all the scenarios is severely limited without CCS technology, and thus boosting the potential to achieve a 50 g/kWh carbon grid emission target by 2030. The current new UK energy policy is proposing a complete phase-out of unabated coal generation by 2025, which makes the scenario projections outlined in Figure 2.11 feasible options for decarbonising the electricity supply sector. The scenario outlook presented proposes a radical transformation of the electricity generation infrastructure driven by record-breaking investment in low-carbon and renewable energy technologies. The technology ambition and the level of deployment of low-carbon and renewable energy sources expressed in these scenarios has assisted in framing the decarbonisation scenarios developed through the EOC, the methodology framework adopted for this thesis.

2.5.3 UK energy scenarios in perspective

The UKERC energy 2050 scenarios highlight the level of emission reduction that can be achieved by the whole energy system under different policy ambitions. Scenario outputs for the electricity generation sector are developed under different constraint systems which include carbon emissions and technology cost assumptions. The electricity generation mix portrayed in these scenarios has a high level of renewable and low-carbon technologies which are central in meeting energy demand and emission reduction targets.

The electricity generation technology representation in the UKERC energy 2050 scenarios are developed based on an ambitious future energy supply outlooks, and thus does not reflect on the actual developments in the UK energy policy. The low-carbon electricity supply outlook projected in the UKERC energy 2050 scenarios has a high proportion of CCS, nuclear and wind in the generation mix. The deployment of these technologies, particularly CCS and nuclear remain uncertainty due to technical and investment issues. Wind energy is variable, and hence its projected outlay in the scenarios presented does not take into account the potential impact of intermittency on its contribution in meeting demand and emission targets.

The FESA scenarios present the low-carbon transition in the context of market, government and civic society perspectives. The electricity supply system transitions to 2050 has a diverse mix of low-carbon and renewable energy technologies to achieve energy demand and carbon emissions. While the technology mix in each scenario over the transition period is reflective of the scenario logic, the technology mix development is not constrained by cost. Hence, the generation mix portrayed in each scenario logic is not determined based on costs. Furthermore, the technology deployment in each scenario is either under or overestimated, which suggests that the scenarios do not reflect on the development of the UK energy policy. Renewable energy technologies, particularly wind, wave and tidal are an integral part of the generation mix in the FESA energy scenarios.

The impact of variability of these energy resources to system reliability is not addressed in these scenarios. As scenarios seeking to trace the evolution of the electricity supply sector to a low-carbon future, it is essentially important that the impact of intermittency of renewable energy resources is assessed so that the scenario outputs capture its effects on security of supply and decarbonisation.

2.5.4 Research gap

The UK energy modelling environments provide a diverse transition pathways seeking to highlight the evolution of the electricity supply sector under different constraints. While the energy scenarios have underscored the importance of a diversified generation mix with high proportion of low-carbon and renewable technologies, it can be concluded that the scenario analogue presented is limited in addressing the issue of intermittency of renewable energy technologies. The determination the level of intermittency of renewable energy resource in scenario assessments is vital in informing energy policy development. It has a huge influence on the deployment and operation of fossil fuel reserves in the electricity generation system. Since the deployment of renewable energy technologies underpin the security of supply and decarbonisation objectives of the UK energy policy, this research integrates wind data analysis in the model framework to assess the impact of variability, particularly on offshore wind. In this respect, the generation mix portrayed in the scenario outputs from this research reflect on the UK energy policy development as well as the key dynamics affecting the electricity sector such as the impact of intermittent renewable energy resources.

2.5.5 Summary

The UK energy and climate policy is driven by the 80 % GHG emission reduction target by 2050 against the 1990 levels. This legally binding target brought with it a system of five-year carbon budgets designed to assist in guiding the economy towards the earmarked low-carbon future by 2050. A 50 to 100 gCO_2/kWh potential decarbonisation target projected for 2030 in the power sector is likely to intensify and accelerate the investment and deployment of renewable and low-carbon energy technologies. Nuclear, CCS and offshore wind are considered to be the key energy technologies that could transform the carbon intensity of the electricity generation infrastructure to near-zero by 2050. A low-carbon electricity generation infrastructure could mitigate climate change wile bolstering the nations' energy security status.

Energy scenarios have been developed to project the low-carbon electricity generation outlook for the UK future. The decarbonisation pathways highlight the least-cost technology mix required to contribute towards the 2050 emission reduction target. However, the energy scenarios developed are limited as they fail to address the issue of variability which affect renewable energy technologies. Since renewable energy technologies are anticipated to contribute significantly in decarbonising the power sector, it is vital that the impact of variability on renewable energy technologies is incorporated in modelling environment. This research gap is mitigated through the use of the EOC which develops scenarios that reflect the impact of intermittency on renewable energy resources such as offshore wind.

Chapter 3 Methodology

3.1 Introduction

This chapter provides a detailed account of the methodology framework adopted in this thesis to explore the transition of the United Kingdom electricity generation infrastructure to a low-carbon future. The analysis of energy system transitions to low-carbon economies have been undertaken using a wide range of modelling approaches with a view to inform policy development. In the midst of a multitude of approaches used to trace the evolution of the electricity generation infrastructure in the wake of decarbonisation policies, this chapter characterises and justifies the use of the EOC in exploring the dynamics that impact on the UK electricity generation sector as it strives to attain a near zero carbon grid intensity outlook by 2050. The adoption of this method framework is strategic in that it provides a quantitative and least-cost approach which assist in defining the performance of the electricity generation sector as it responds to the environmental, technological and economic challenges of attaining a low-carbon status from now through to 2050.

While the characterisation of the EOC is the prime priority of this chapter, attention will also shift to discuss other key modelling approaches that have been used in the energy policy discourse with the purpose of providing insights into future energy policy development. An integrative exposition of these key modelling tools seeks to offer a better understanding of the different approaches that have been devised to explore alternative decarbonisation pathways for the UK's low-carbon energy future. Therefore, in justifying the preference of the EOC against other approaches, this chapter offers a background description of the model, operation, modifications and model testing in line with addressing key research questions as outlined in Section 1.4.

3.2 Preview of energy transition modelling approaches

3.2.1 UK MARKAL Elastic Demand (MED) Energy Model

The MARKAL energy model framework is a bottom-up, dynamic, linear programming optimisation approach that has been instrumental in assisting the UK policymakers to access the costs, trade-offs and pathways related to achieving long-term emission targets and energy security (Strachan, 2011). MARKAL is described as a ‘perfect foresight’ (assumed to have perfect inter-temporal knowledge of future policy and economic developments) partial equilibrium optimisation model, which minimises the discounted total system cost by considering the investment and operational levels of all the interconnected system elements as displayed in Figure 3.1 (Anandarajah et al., 2009). Figure 3.1 gives a description of the energy flows through a network of technologies involved in the production, transformation and use of different forms of energy. The model portrays the entire energy system (see Figure 3.1) from fuel source production, through processing and supply with a comprehensive representation of infrastructures, energy conversion processes, end-use technologies and energy service demands of the entire economy (Kannan, 2009). Based on this integrated energy system analysis, the model has the aptitude to allow wider system interactions of electricity resources and usages to be considered, thereby facilitating a sectoral approach to tracking the evolution of the energy system. The model optimises (minimises) the total energy system cost based on the investment and operational levels of all the interconnected energy system elements (Usher & Strachan, 2010).

Structurally, the model has a network of modules which act as centres of information, and thus enabling each component of the energy system to be modelled. The base module contains all energy carriers such as natural gas, coal, oil, uranium and emission carriers. The different elements within the base module are interlinked with sub-modules to facilitate the adoption and application of a whole system approach in simulating the energy system as shown in Figure 3.2. Modelling in MARKAL means that each module has its own set of data inputs and assumptions, and thus making the modelling environment complex and data intensive. The costs accrued in any particular scenario development are presented in terms of the energy system and the welfare costs. Scenario assessments with increasingly constraint emission reduction targets tend to follow similar emission reduction pathways, with diverse low-carbon and policy measures being required to keep up with even tighter carbon targets and rapidly spiralling costs. The hallmark of the energy system evolution in MARKAL is captured through the inclusion of a range of policies, physical constraints and the application of all taxes and subsidies, and thus, enabling the development of plausible energy scenarios (Anandarajah et al., 2009).

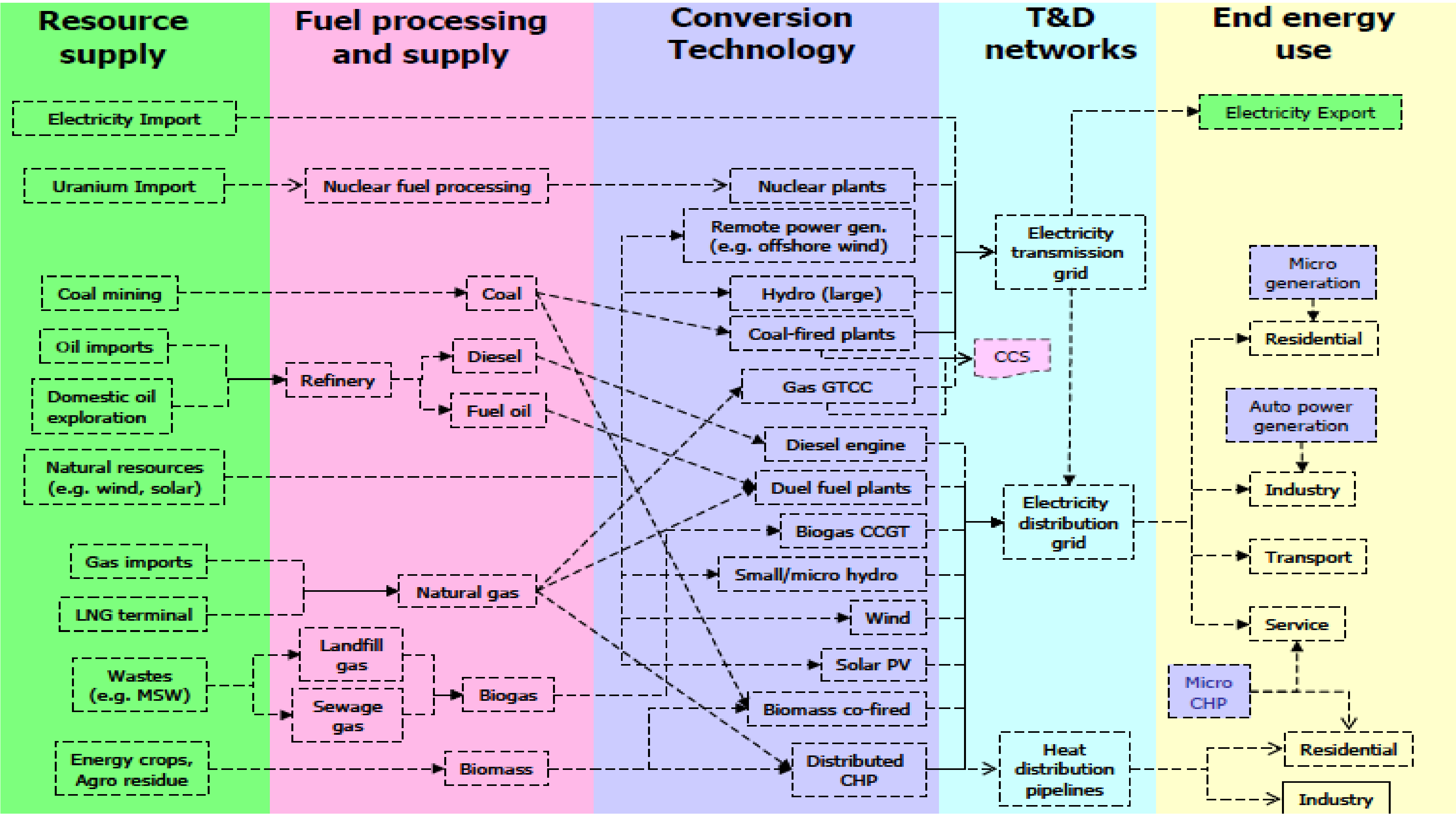

Figure 3.1. MARKAL Reference Energy System Model (Kannan et al., 2007).

The structural complexity of the MARKAL model has been flagged as one of the main limitations associated with its supposedly data intensiveness, which subjects the key datasets to a wide range of uncertainties (Kannan, 2009). The technology cost data computed in the MARKAL does not take into account uncertainties associated with investment decisions such as market risks, financing and policy implications (Kannan, 2009). Due to the extensive nature of the model, technological plant data such as technical availability, technical lifetime of plants and the geographical constraints on electricity resources and infrastructures are not fully modelled within the MARKAL modelling environment (Kannan, 2009). The cost optimisation characteristic of the model has being criticised for over estimating the deployment of cost-effective energy technologies by assuming perfect energy markets with no due regard to barriers and other non-economic factors that influence decisions.

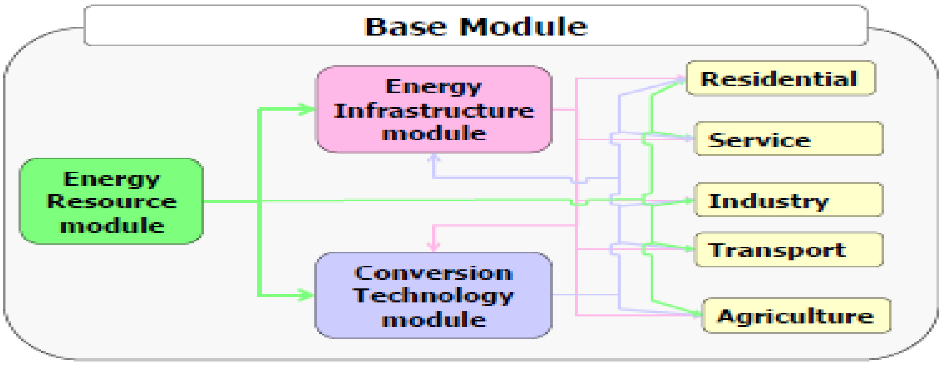

Figure 3.2. Structure of the UK MARKAL Modules (Kannan et al., 2007).

3.2.2 The Energy System Modelling Environment (ESME)

Energy System Modelling Environment (ESME) is a least-cost optimisation, policy neutral model developed by the Energy Technologies Institute (ETI) to examine the underlying cost and engineering challenges of designing energy systems (Heaton, 2014). As a long-term energy forecasting model, ESME uses linear programming to assess cost-optimal technology portfolios. The model uses a mathematical programme similar to that used in other bottom-up, optimisation models such as MARKAL, where the objective function is to minimise total economic surplus subject to constraints (Pye et al., 2014). In designing and guiding priorities for diversified technology programmes, ESME considers the impact of uncertainty particularly in future energy prices, fuel and technology cost as well as the performance of energy technologies in a policy neutral modelling environment. At the backdrop of this modelling prowess, ESME has been used to support work by the CCC on carbon budgets and its renewable energy review as well as work by the Department for Energy & Climate Change (DECC) on the Carbon Plan (Heaton, 2014).

The model adopts a whole system approach in analysing energy system design. The technology framework used includes all major flows of energy, that is, fossil fuel production, electricity generation, and end-use energy services as depicted in Figure 3.3. The sectoral approach used by the model facilitates a high-level cost optimisation process that analyses the different combinations of technologies which together minimises the total cost while meeting desired sustainability indicators framed under different scenario development and constraint systems.

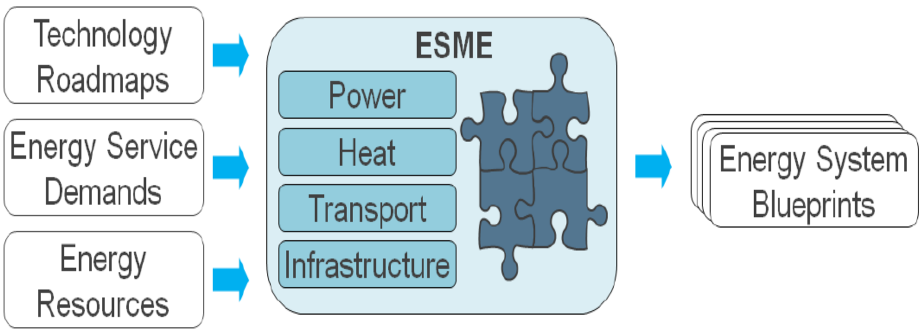

Figure 3.3. Schematic diagram of the ESME Model; Input assumptions for the 2010 - 2030 energy pathway (Heaton, 2014).

The model is policy neutral, and thus implying that its modelling approach does not incorporate taxes, subsidies and other policy related incentives which affect technology and fuel costs. The exclusion of these policy influences in developing plausible future energy system designs is meant to provide a workable framework upon which policymakers could use to determine ideal policies, markets and incentives that could be harnessed to deliver energy systems for the future (Heaton, 2014). This aspect of the model makes it an ideal tool for developing insights with relevance to wider national low-carbon energy futures. As in MARKAL, ESME adopts a bottom-up approach to energy system analysis which allows for specific technical opportunities and their energy cost and emission implications to be considered within the modelling environment. The 'whole system' approach assumed by the model implies the use of a very large dataset (Heaton, 2014) which somehow limits the individual technology detail within the system.

3.2.3 The DECC 2050 Calculator

The DECC 2050 Calculator is an excel-based online interactive model framework developed by DECC to allow users to explore a range of potential energy pathways from now through to 2050 in line with the 80 % emission reduction relative to 1990 levels (HM Government, 2010). The calculator is user-friendly which allows users to select their choice of technologies to decarbonise the UK energy system. As a non-optimisation tool, the model's outputs highlight the implications of the user's chosen parameters on the energy mix, emissions and the indicative costs. The sectoral analysis approach adopted by the model shows the level and type of innovative change that would need to be implemented in order to transform the energy system to achieve the demand and emission targets set. The performance of the energy system is determined based on a 'four level system' (1-4), with each level representing the potential roll-out of energy supply infrastructure or technology development projected for each sector, which denotes the levels of effort as illustrated in Figure 3.4. The energy infrastructure development levels as used in Figure 3.4 are described as follows (HM Government, 2010):

i. Level 1: assumes little or no attempt to decarbonise the energy supply infrastructure. It is characterised by lack of or unavailability of unproven technologies being development or deployed

ii. Level 2: represents a future energy outlook likely to be achieved through the application of measures or level of effort that could be viewed as ambitious but reasonable in the context of the UK energy supply development

iii. Level 3: describes a future energy outlook driven by a very ambitious level of effort involving significant changes from the current system as well technological breakthroughs

iv. Level 4: presents a level of change that could be achieved through extreme measures likely to be perceived as physically plausible. It is an optimistic level that pushes towards the physical limits of what can be achieved.

The evolution of the energy system, observed under these level point systems, assist users in building their preferential scenarios that achieve perceived energy futures. The levels of energy system development represented is indicative of the lead times and build rates of new infrastructure as determined by physical, investment, international developments and public acceptance possibilities and decisions (HM Government, 2010). Although the results obtained from the calculator are purely determined by user perspective, with little impact in influencing energy system policy development, the tool does demonstrate the complexities and synergies that exist between technologies and policy. Also, it considers the difficult choices and trade-offs that would have to be made in order to develop a sustainable energy systems for the future (HM Government, 2010). The 2050 Calculator was designed primarily to foster public engagement by allowing users to explore alternative pathways to decarbonise the energy system, and thus helping to gain insight into various approaches for climate change mitigation.

The major limitation of the model is that it doesn't identify the least-cost way of meeting the 2050 target. Instead, the model's focus is directed at establishing the physical limits that can be attained in each sector to achieve the decarbonisation targets explored under different user based assumptions. The sectoral levels of infrastructure development proposed by the model are rather ambitious, and hence the level of infrastructural development proposed is not financially feasible from an investment perspective. Levels 3 and 4, for example, are not likely to be attained by the current UK energy policy instruments given the difficulties encountered in the financing and development of CCS and new nuclear plant technology. The suitability of the DECC 2050 Calculator for simulating the transition of the UK electricity supply infrastructure is limited due to the lack of constraint systems that control the level of deployment of the technologies included in each pathway. Therefore, in order to build confidence in the value of the scenario outputs from the model for the purpose of informing energy policy and technological development, it is expedient that the results are used in conjunction with other scenarios derived from reputable modelling approaches such as MARKAL and ESME.

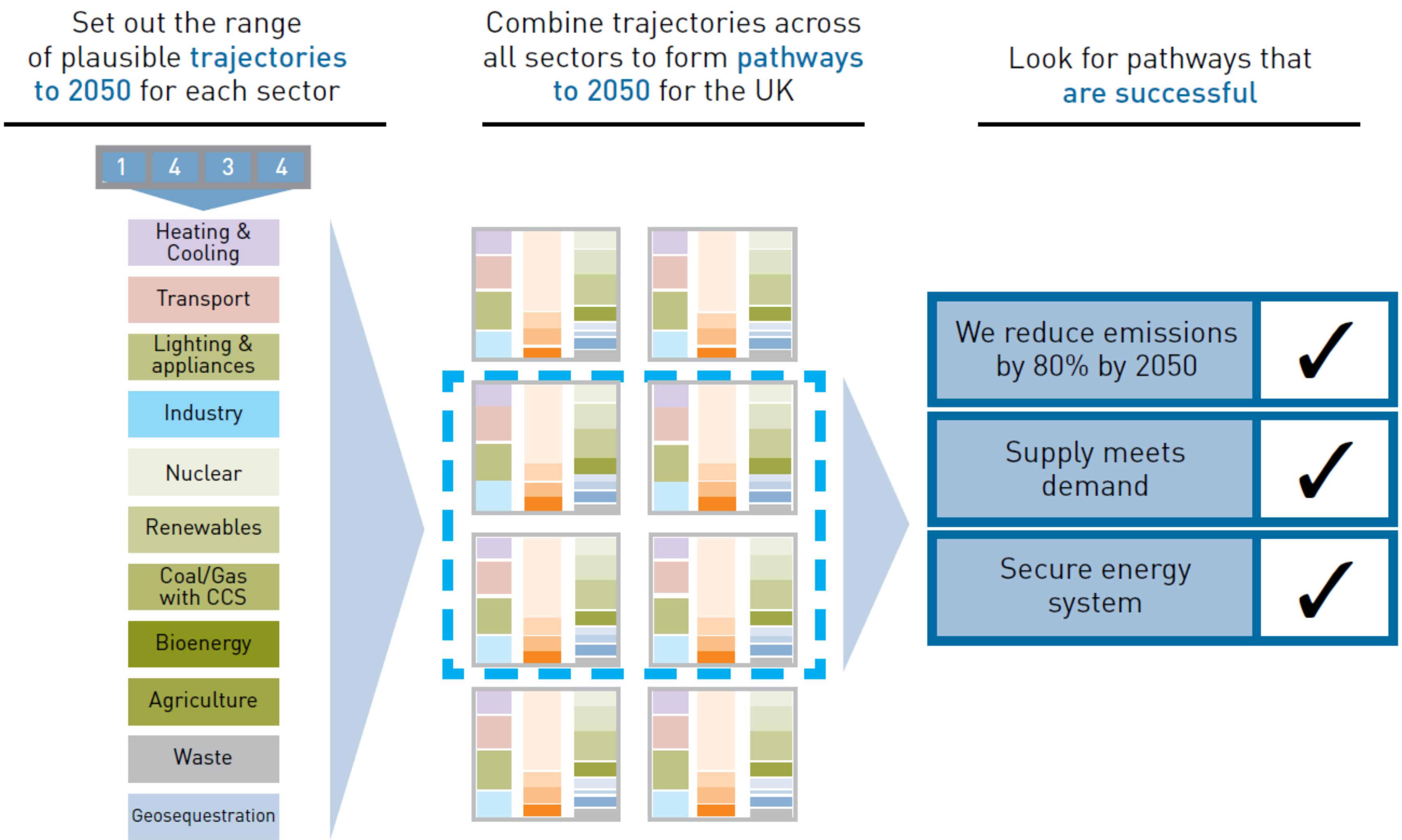

Figure 3.4 Schematic framework of the DECC 2050 Calculator for developing sectorial trajectories (HM Government, 2010).

3.3 The ‘Energy Optimisation Calculator’

3.3.1 Background overview

The EOC as described in Shah et al. (2013), is a model built on a Visual Basic Programming system which uses macros (a sequence of instructions) to accomplish tasks in Microsoft Excel. The Visual Basic framework used in the model is made up of programs consisting of small, discrete units of code (procedure) each which acts independently to accomplish a particular task (Doyle and Mattenson, 1995). Written codes used in the EOC are programmed into procedures, modules and workbooks. The modules as applied in the EOC represent workbook sheets that contain codes and each of the modules contains declarations followed by procedures. On the other hand, procedures are units of code enclosed between Sub and Sub End or Function and Function End statements (Doyle and Mattenson, 1995). Thus, the application of the Visual Basic program in the EOC facilitates data storage and exchange across modules and workbooks which can be accessed by procedures through arguments.

Outputs from the EOC were used to inform a study entitled: Halving global CO_2 by 2050: technologies and costs undertaken by the Energy Futures Laboratory and Grantham Institute for Climate Change at Imperial College London in 2013 (Shah et al., 2013). The study sought to access the future global energy demand from the building, transport and industrial sectors and its impacts on emissions against the objective of limiting global warming to about 2 ^{o}C below pre-industrial levels. According to this study, this level of decarbonisation was thought to represent about 15 $GtCO_2$ per annum by 2050 (Shah et al., 2013). In developing a methodology approach to address the study objectives, the global community was divided into ten geographical regions to allow for the assessment of the impacts of economic and population growth on sectorial emission performance. The influence of economic and demographic growth on primary energy use in electricity generation in each region has profound implications on overall emissions. Therefore, it became apparent that a quantitative modelling approach in the form of the ‘Energy Optimisation Calculator’ was needed to assemble an array of technologies both existing and emerging which could combine in cutting energy and industrial process carbon dioxide emissions to a level consistent with a 2 ^{o}C temperature rise by 2050.

The model framework has two scenario constructions adopted to characterise the global sectorial emission performance on the path to a 2 ^{o}C warming limit. The reference scenario or the Low Mitigation Scenario (LMS) was adopted for each region to represent a policy discourse demonstrating a limited scope to mitigate climate change. On the other hand, the low-carbon scenario (LCS) ascribed for each region represents a deliberate climate change policy mitigation approach seeking to transform the emission performance landscape of the different sectors of the global economies in the context of avoiding dangerous climate change. The model has three interactive spreadsheets:

i. Input Data Sheet

ii. Master Control Sheet

iii. Output Data Sheet

The input parameters of the LMS and LCS are determined in the first two spreadsheets of the calculator while the least-cost and emission abatement technology mix developed is shown in the output data sheet as shown in Appendices A1; A2; A3 and A4. The input data sheet and master control sheet have cells that have both a pale green and yellow colour coding. The pale green coloured cells contain the input variables which can be modified at the user's discretion. On the other hand, the yellow coloured cells are updated automatically during the model's calculations. These two colour codes can be seen exclusively in the input data sheet and the master control sheet, while the entirety of the output data sheet is yellow coded to represent the model calculations (outputs), see Appendices A1, A2, and A4.

In each scenario, the cost of operating the energy system (capital, operational expenditure and fuel costs) is determined based on the cost input data derived from current UK government based energy policy documents. The deep cuts in GHG emissions espoused by the LCS adopts a generation mix of both existing mature and emerging technologies including those that are currently undergoing demonstration and awaiting full scale commercialisation and deployment such as CCS, wave and tidal. The optimal generation mix that achieves a decarbonisation target commensurate with 80% emission reduction by 2050 is determined by the optimisation function of the calculator which deploys the available generation plant according to a cost and emission-minimisation algorithm.

3.3.2 Model Modifications: Adapting the calculator to the UK electricity generation infrastructure context

Since the model was originally developed to simulate the global energy system transition towards a 15GtCO_2/yr emission target by 2050, there was a need to modify and adapt it to a national level so that it could be used to investigate the dynamics that impact on the UK electricity generation sector in the context of the research questions outlined in Section 1.4. To start with, one of the ten regions (European) was changed to United Kingdom and the rest were turned off to avoid interfering with the mathematics and the intricate workings of the model. The process of developing a UK focused optimisation model involved changing the technology mix to reflect the existing and anticipated emerging technologies likely to contribute in meeting the energy demand as well as decarbonising the economy in line with the 80 % GHG emission target by 2050 against 1990 levels.

The two scenario constructions, that is, the Baseline Scenario and Low-Carbon Scenario, were retained as was the case in the original structure of the model. However, the Baseline Scenario was adapted to the UK electricity generation framework by computing the generation mix influenced by the imbedded policies existing in 2007 (see Appendix A1). This reflects a period in which the electricity generating infrastructure was in perpetual lock-in to high carbon intensive fossil fuels. This scenario also reflects on the electricity demand and emission target influenced by policies with no aptitude to mitigate climate change. The predominantly fossil fuel based generation mix of the baseline scenario has the electricity demand set at 379.2 TWh with a cumulative emission output of about 185.8 MtCO_2e (DUKES, 2008). On the other hand, the LCS commands a high proportion of renewable and low-carbon energy technologies in the generation mix. It constitutes an ambitious technology mix whose composition includes emerging technologies which are at an early stage of development or application. The low-carbon scenario development is modelled respectively under emission and electricity demand constraints outlined in Tables 3.1 and 3.2 in line with the scope of the research questions being investigated in this thesis.

The electricity generation mix variations portrayed in the scenario developments in this thesis are influenced by the different emission target ambitions that have been proposed or expressed as potential options for decarbonising the electricity sector. The ‘path to 50 g and 100 g' emission reduction trajectory by 2030 represent the CCC's cost-effective emission reduction framework seeking to achieve the 80 % target by 2050 relative to the 1990 levels (CCC, 2010). While there is consensus on the need to decarbonisation the electricity sector by 2030, the government's ambition appears to be focused on the 100 and 200 g/kWh grid carbon intensity targets as the potential preferential options to cut power sector emissions by 2030. The electricity generation sector transition outlined in this thesis endeavours to capture the divergence in policy ambitions to depict the future outlook of the sector both in 2030 and 2050. The current emission projections for the UK electricity generation sector for the 50 g and 100 g decarbonisation milestones are estimated up to 2030. The emission reduction trajectory from 2035 to 2050 (see Table 3.1) for the two pathways is extrapolated exponentially based on Equations 3.1 and 3.2, respectively, (Sithole et al., 2016):

$$y = (5 \times 10^{76})e^{-0.085x} \tag{3.1}$$

Where y is carbon emissions ($MtCO_2e$), x is the year and e is the exponential notation.

$$y = (2 \times 10^{67})e^{-0.075x} \tag{3.2}$$

Where y is the total carbon emissions ($MtCO_2e$), x is the year and e is the exponential notation.

Table 3.1. The 2030 decarbonisation trajectory for the electricity generation sector in $MtCO_2e$ (CCC, 2010).

Year	2010	2015	2020	2025	2030	2035	2040	2045	2050
'Path to 50g'	157	131.4	63.5	26.9	20.7	10.3	5.9	3.4	1.9
'Path to 100g'	157	131.4	63.5	43.9	41.6	10.3	7	4.9	3.4

The electricity demand target over the transition period 2010 – 2050 is drawn from the DECC's updated energy and emission projections (DECC, 2014c). The primary energy demand outlook currently informing UK energy policy is projected to 2035 and the trend to 2050 is lineally extrapolated using equation 3.3 (Sithole et al., 2016):

$$y = 0.4127x^2 - 1667.7x + (2 + 10^6) \tag{3.3}$$

Where y is energy demand in TWh and x is the year.

Table 3.2: Projected primary electricity demand (DCC, 2014).

Year	2010	2015	2020	2025	2030	2035	2040	2045	2050
Electricity demand (TWh)	345	324	303	301	344	388	436	519	620

The carbon life-cycle of all the electricity generation technologies computed in the calculator is updated in accordance with peer-reviewed estimates, and thus, providing a comprehensive picture of the emissions caused at the point of electricity generation as well as during construction, maintenance, decommissioning and disposal. The original fuel cost input used in the model was based on global price, but for the purpose of this thesis, the cost input element was changed to a local price index to reflect the actual UK expenditure on fuel used in electricity generation. As with electricity demand, the fossil fuel (coal and gas) prices have been projected to 2035 (DECC, 2014), however, the fuel cost outlook from 2040 to 2050 is respectively extrapolated using equations 3.4 and 3.5 (Sithole et al., 2016):

$$y = (1.3502 - 10^{9})e^{(1.2343-10^{2})x} \qquad (3.4)$$

Where y is the coal price ($/t), x is the year and e is the exponential notation.

$$y = (4.2433 - 10^{11})e^{(1.3882-10^{2})x} \qquad (3.5)$$

Where y is the gas price (p/therm), x represent the year and e id the exponential notation.

The above equations (3.4 and 3.5) have been used to project the fuel cost trend highlighted in Table 3.3. The fuel price for nuclear is based on the £6/MWh with an additional £2/MWh waste disposal charge (Mott MacDonald, 2010). Also, the wood fuel price is calculated based on the 4.4p/kWh (Biomass Energy Centre, 2011) and both nuclear and wood pallet costs are fixed throughout the transition period.

Table 3.3: Local fuel prices–£/GWh fuel (Sithole et al., 2016).

Year	2010	2015	2020	2015	2030	2035	2040	2045	2050
Coal	62434	51995	60093	63178	66391	69797	74953	79103	83253
Gas	3914	5652	5488	6526	6953	6953	7717	8191	8666
Wood	23292	23292	23292	23292	23292	23292	23292	23292	23292
Nuclear	8000	8000	8000	8000	8000	8000	8000	8000	8000

The investment outlay used in the model to determine the cost of construction and operation of the electricity generation infrastructure is also adapted to the UK energy context. This implies that the economics of the model was revised to reflect the currency in British pound sterling as opposed to the US$ as originally structured in the model. Technology and system operation cost data used in the model is based on the up-to-date cost assumptions used in various modelling work reported in key government reports (Mott MacDonald, 2010; ECC, 2011a; 2012; Parsons Brinckerhoff, 2011; 2012) as shown in Table 3.4. Most government projections on the future technology development and deployment outlook of the electricity generation mix have tended to focus on the medium/central cost estimate. As this research sheds light into the development of the UK energy policy, the central cost estimate is used in the analysis of the electricity supply sector transition towards a low-carbon future. The cost estimates used in this thesis is drawn from reports produced from 2010 to 2013 (Mott MacDonald, 2010; DECC, 2011c; DECC, 2012; Parsons Brinckerhoff, 2011; Parsons Brinckerhoff, 2012). In this respect, the data has been updated/harmonised to 2013 prices using the UK rate of inflation from 2010 to 2013.

Table 3.4. The capital and operational cost inputs for the different technologies in the UK electricity generation mix (Sithole et al., 2016).

Technologies	Medium Capex £/kW	Medium Opex £/MW/y	Data source
Onshore wind (NOAK)	1,596	75,396	
Offshore wind (NOAK)	2,851	181,773	
Renewable (Biomass) CHP	4,272	222,371	DECC, 2011
Hydroelectricity	2,417	88,462	
Biomass	2,532	252,289	
Pumped storage	1,958	12,570	Parsons Brinckerhoff, 2011
Nuclear (FOAK)	4,428	94,688	
Biomass CCS	4,118	131,092	
Gas CCGT (NOAK)	599	22,655	
Gas CCGT–CCS	1,369	39,674	Parsons Brinckerhoff, 2013

Conventional CCGT CHP	618	47,214	
Coal (Pulv fuel, ASC-FGD	1,954	60,602	
Coal CCS (Pulv, ASC, CCS	3,354	120,383	Mott McDonald 2010
Wave	3,610	200,000	
Tidal	2,750	37,200	DECC, 2011
Solar	780	20,400	DECC, 2012

The technology build-up rate is another component of the model that was changed to align the modelling framework to the UK electricity generation landscape. The data on the annual technology build-up rates is drawn from the technical input data of the Levelised Cost Model (Mott MacDonald, 2010; Parsons Brinckerhoff, 2012) developed to aid policy development as well as enhance the feasibility of the low-carbon deployment projections envisaged over long time frames. Most modelling work on the future UK electricity infrastructure assume a 10 % discount rate to annualise the investment costs. This thesis adopts the same discount rate assumption as opposed to the 3.5 % originally used in the calculator.

3.3.3 Scenario development for different transition pathways

The process of developing pathways to a low-carbon electricity supply system requires radical changes to the technologies, institutions and business strategies (Foxon et al., 2010). The impact of these elements have been considered and integrated within the modelling environment of the EOC to produce electricity generation pathways that seek to project decarbonisation ambitions aspired by various institutions with a stake in the evolution of the UK energy system to a sustainable future. Depending on the decarbonisation ambition being advanced and the assumptions made, the methodology framework used in this thesis has the capacity to assemble a diversified and optimal generation mix that can contribute in achieving the 2050 low-carbon future.

The input parameters outlined in Section 1.3.2 form part of the key variables computed in the EOC. The penetration of individual technologies within the model is constrained in two stages (physical installation limit and installation constraint) to allow the model to predict plausible scenarios reflective of both policy and technological developments. The deployment outlay for each technology represented in the model is drawn from industrial, academic and government policy estimates developed from rigorous modelling frameworks with a view to explore alternative options to decarbonise the power sector. The physical installation limit is one of the key structural components of the model which allows the maximum capacity of each technology to be computed within the model (see Appendix A1). This physical installation limit provides sufficient capacity from which the model can build or shut down plants depending on the level of electricity demand and emissions target that is set to be achieved in each model simulation.

The installation constraint sets the maximum deployment capacity that each technology can achieve in the optimisation process. This installation constraint limit for each technology is set in line with the potential deployment prediction expressed within the prevailing policy and industrial technology development estimates. This constraint category also determines the diversity of the generation mix that the model can achieve given the emission and energy demand constraints set within the modelling framework. The model sets a 1 GW minimum capacity for each technology to allow each technology to contribute to generation mix in line with the model assumptions defined. However, this minimum capacity level can be modified to suit the modelling requirements specific to the decarbonisation pathway ambition under review. It is through this minimum capacity component of the model that developments in emerging technologies such tidal and wave at demonstration stage, with capacities usually below the 1 GW capacity level, to which the model operates, can easily be represented. Also, it allows plant closures, for example coal in 2030 to have a zero input both in the physical installation limit and installation constraint input without compromising the model calculations (constraints set in input data sheet – Appendix A1).

The load factor for the baseload generation that is, coal, gas CCGT and nuclear from 2010 to 2015 has been framed based on the actual data from the Digest of United Kingdom Energy Statistics (DUKES). However, beyond this, the load factors for these technologies have been influenced by the emission target, electricity demand constraints and the proportion of other generation technologies available in the model at a given time. As for the emerging technologies such as CCS, wave and tidal which are yet to attain commercial status within the generation mix, their load factors are determined based on forecasts from industry and research analysis. Load factors for variable renewable technologies such as onshore wind, offshore wind, solar PV have been based on annual averages reflecting the general weather patterns across the British Isles (see Appendix A1).

3.3.4 Determining the modelling assumptions

The main modelling assumptions considered in developing the low-carbon pathways in this thesis have been centred on the main uncertainties facing the electricity generation sector. While there is consensus on the role of the power sector in decarbonising the UK economy to 2050, there is currently no legislated target to which the sector should decarbonise. The radical reduction in emission for the power sector hinges on the roll-out of nuclear, offshore wind and fossil fuel plants fitted with CCS. The growth of offshore wind to achieve the ambitious deployment levels projected by policy and industry for sector decarbonisation is dependent on the cost reduction to reach £100/MWh by 2020 (DECC, 2012d). On the other hand, the outlook for a 16 GW new nuclear target by 2030 (HM Government, 2013) could be difficult to achieve considering the on-going delays and investment uncertainty currently experienced by EDF's Hinkley Pont C new nuclear power project that is yet to reach FID. The timeline for CCS deployment is still a matter of speculation as the technology is currently at demonstration stages and its commercialisation is dependent on the technical and economic viability of the technology.

The future role of unabated fossil fuel generation in the mix is also unknown, even the current developments in the UK shale gas and its prospective role in the generation mix is subject to speculation. There is still uncertainty regarding the capacity of coal fired generation that could be upgraded to meet the EU's tough emission standards. The coal plants that manage to comply with EU pollution regulations, could have their future in the generation mix severely limited owing to the potential economic impact of the 'carbon price floor' a high carbon tax that could make operating coal facilities economically unviable. Furthermore, the continual operation of coal-fired utilities in the generation mix is also dependent on the availability of capital resources to extend the life of the plants beyond their technical operational life. Therefore, there is no doubt that the evolution of the electricity generation infrastructure to a low-carbon future is beset with a multitude of challenges which form the basis of the research questions developed for this thesis. The dynamics that impact on the electricity generation sector as it transitions to a low-carbon future are modelled based on the following assumptions:

i. Decarbonisation targets of 50, 100 and 200 gCO_2/kWh are adopted for different policy ambitions by 2030.

ii. The electricity supply sector achieves a near-zero carbon grid intensity by 2050.

iii. Commercialisation of CCS, wave and tidal to start in 2025.

iv. Coal generation phased-out in 2025 for the 50 and 100 gCO_2/kWh energy transition pathways.

v. Full scale shale gas production and utilisation in the power sector to commence in 2025 with the wholesale price pegged at 30% lower than conventional gas.

vi. Majority of the UK nuclear fleet retired by 2023 with 1050 MW and 1198 MW capacity respectively retired in 2028 and 2035. Any additional nuclear capacity beyond 2023 constitutes a fleet of new nuclear power plants.

vii. With respect to 200 gCO_2/kWh decarbonisation target by 2030, some coal fired generation plants had a ten year operational life extensions as from 2023.

viii. The cost of biomass and nuclear fuel resource is constant throughout the transition period.

3.3.5 Optimisation: Determining an optimal generation mix

The optimisation process aims to develop a least-cost and polluting generation mix that meets the electricity demand and carbon emissions for the scenario under study. Optimisation starts with the generation technologies defined in the baseline scenario as shown in Figure 3.5 which are modified to develop a desired transition pathway based on the input parameters and the various constraints applied. The model develops the optimal generation mix in a two-stage sequential process based on the cost of electricity and emission target set. This implies that for the electricity demand set, the model builds the cheapest technology first, at a cumulative rate of 1 TWh at a time until the installation constraint limit set in the model is reached before moving to the next cheaper technology. The process of building the technology mix is based on the least-cost hierarchy and is repeated for all the technologies in the mix until the electricity demand is achieved. In the event that the generation portfolio developed in each model run fails to meet electricity demand, the model continues its optimisation process by closing down the most expensive technologies and replacing them by building/adding cheaper sources to the mix until demand is met by the least-cost generation mix possible (see Figure 3.5 and Appendix A3).

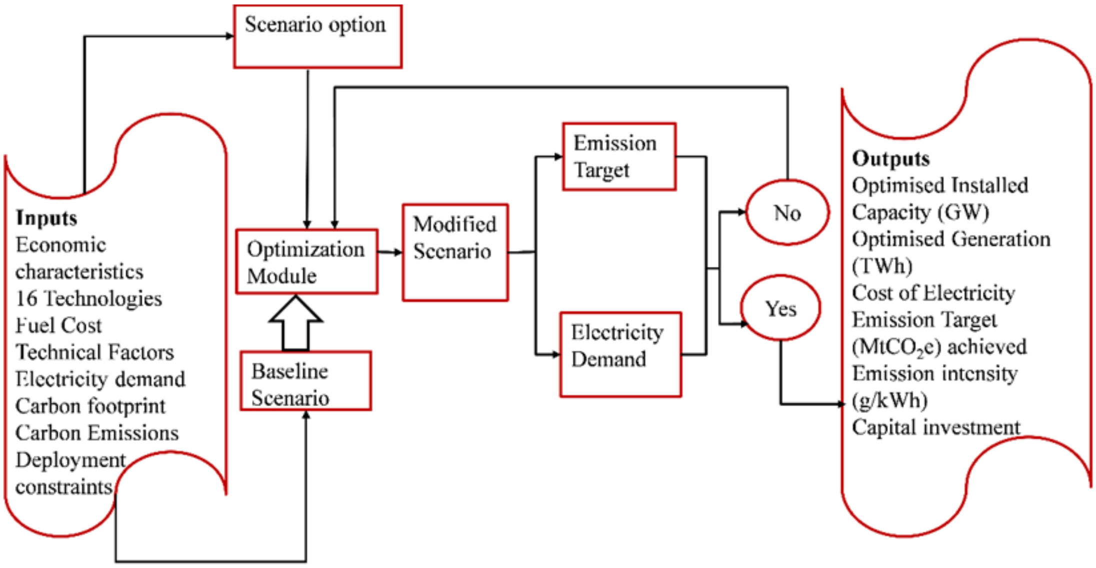

Figure 3.5. Simplified flow chart of the 'Energy Optimisation Calculator' (Sithole et al., 2015; Sithole et al., 2016).

The next stage in the optimisation process assesses the capacity of the assembled least-cost generation mix to meet the emission target. If the assembled generation mix achieves the emission target set, the process ends, but if not, the optimisation procedure would continue. At this stage the model replaces high carbon intensive technologies with low carbon technologies until the carbon target is just met, as depicted in the model flow chart in Figure 3.5 and in the Master Control Sheet (Appendix A2). The ideal generation mix that achieves the conditions set in the model is presented in the output data sheet of the model (Appendix A3 and 4). During the optimisation process, the model keeps track of the total investment accrued in developing the generation mix that meets the conditions set for both the baseline and the low-carbon scenarios as highlighted in Appendices A2 and A4. The model calculations also account for the extra investment resulting from the capacity added to the mix during the optimisation process. Also, the model calculates the overall cost of electricity from the optimal generation mix assembled to meet both emission and electricity demand targets set (see Appendices A2 and A4). Once the optimisation process is completed, the output module then displays the proportion of generation capacity (GW) required to meet the demand from the assembled technologies and the corresponding generation achieved in TWh/yr, as highlighted in Appendices A3 and A4.

3.3.6 Levelised Cost of Electricity

The levelised cost of electricity (LCOE) has been defined by the International Energy Agency (IEA) as the average price that consumers would have to pay the investor/operator so that the capital, operation and maintenance and fuel expenses is repaid exactly with a rate of return equal to the discount rate (IEA, 2005). This cost methodology has widely been used as a ranking tool to assess the cost-effectiveness of different energy generating technologies (Short & Packey, 1995). This technology accounting approach has been used by policymakers to determine the relative investment options available for different technologies. As outlined in this thesis, the LCOE considers the lifetime generated energy and costs to determine the price of electricity per unit energy generated (£/MWh). The assessment of the levelised cost of electricity (LCOE) for any given technologies is framed by a set of assumptions on a wide range of parameters, such as capital cost, construction times, the expected plant life, operational and maintenance costs, fuel costs, plant availability, capacity factor and the discount rate (Gross et al., 2010).

The LCOE data reported in most of UK energy policy documents has been based on the central cost estimate which focuses on the central estimate of economic growth and fossil prices. The central cost estimate level incorporates all agreed policies drafted to promote economic development, and hence its adoption in the energy scenario development pursued in this thesis. In assessing the LCOE structure of the technologies considered in this thesis, the stream of future costs and generation outputs are discounted by 10 % to the present value taking into account the time value of money. The electricity generation infrastructure cost models used by DECC, Mott MacDonald and Parsons Brinckerhoff to determine the UK technology costs incorporates a 10 % discount rate reflecting the return on capital for an investor in the absence of specific market or technology risks (IEA, 2010). For conformity purposes, this thesis has adopted the same discount rate in all scenario assessments. The competitiveness of each of the technologies considered takes into account the likely impact of the sensitivity on the various input parameters adopted in the model. The model formula used to calculate the COE is expressed in equation 3.6 as follows (Sithole et al., 2015; Sithole et al., 2016):

$$COE = \frac{I}{\left[\frac{(1+r)^n}{r(1+r)^n}\right] \times E} + \frac{TOM}{E} \tag{3.6}$$

Where *I* is the capital investment (cost per kW multiplied by the total installed capacity), *r* is the discount rate at 10 %, *E* is the annual electricity generation (TWh), *n* is the lifetime of the plant, and *TOM* is the total operation and maintenance costs. It is through this levelied cost analysis framework that the overall unit cost of the generation mix is determined as well as the cost of generating electricity from each technology.

3.3.7 Simulating intermittency: offshore wind generation by 2030

The 31.2 GW total installed capacity for offshore wind modelled for the 'path to 100 g' carbon grid intensity by 2030 is presumed to come from the Crown Estate leased zones 1, 2 and 3 that are illustrated in Figure 3.6. The UK Met Office Meteorological observation map was used to identify weather stations located in proximity to the proposed offshore wind site development zones as shown in Figure 3.6. The wind data is downloaded from the MERRA (Modern Era Retrospective-Analysis for Research and Applications) based on the grid points (latitude and longitude) for the selected site. The MERRA meteorological dataset model was preferred for sourcing wind data for this thesis since it has a relatively high temporal and spatial resolution (hourly average) and has data available from 1979 complete with wind speed at different heights/pressures levels, wind direction, temperature, moisture content available for download free of charge (NASA, 2016). Hourly datasets for wind speed at 50 and 80 m heights over a thirty year period are downloaded from the MERRA. For the purpose of this research, hourly wind speed data for five years for each of the wind sites is analysed to determine the electrical power output from the proposed wind farm sites (Figure 3.6) based on the V164-8.0 and the SeaTitan 10 MW wind turbines (MHI Vestas Offshore Wind, 2014; AMSC, 2012).

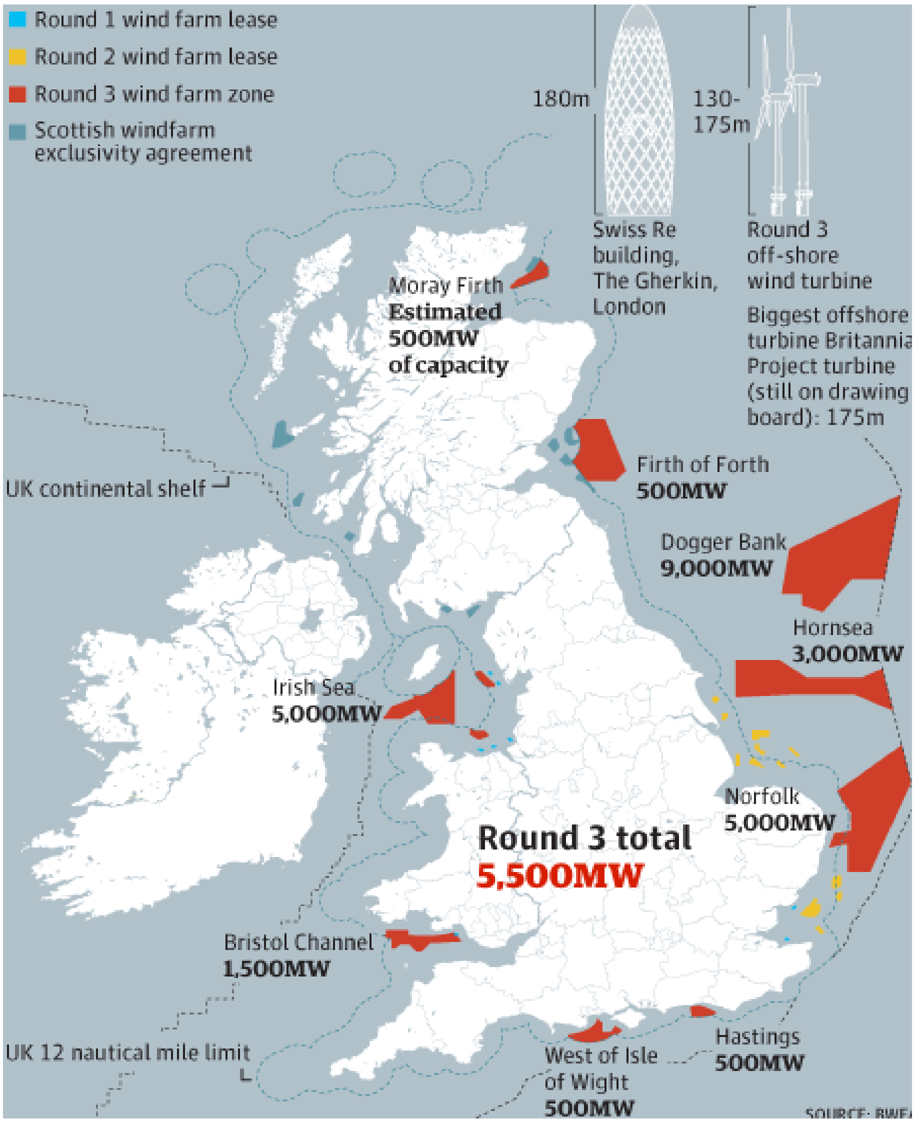

Figure 3.6. UK offshore wind development rounds (BWEA/RenewableUK, 2010).

3.3.7.1 The Weibull density distribution: wind data analysis

The wind power density is a key indicator in wind energy assessments that determines the potential amount of wind energy that can be captured or harnessed from a wind resource at a given site (Mohammadi et al., 2016). The characterisation of the wind resource through a power density distribution function of wind speed is vitally important as it provides insight into the proportion of the wind resource that can be converted into electricity using wind turbines. The Weibull density distribution function provides a statistical model through which the wind speed distribution frequency can be described (Lun & Lam, 2000). It is perceived to be an ideal approach that gives a good representation of the variation in hourly mean wind speed over a year at many typical sites (Burton et al., 2011). As a prominent and broadly utilised approach in wind energy investigations (Arslan et al., 2014), the Weibull density distribution is characterised by two important parameters known as shape (k) and scale (c) parameters.

Shape k parameter indicates the width of the wind speed distribution, which represents the wind distribution peak at any given site (Carrasco-Díaz et al., 2015). On the other hand the scale c parameter denotes the abscissa scale of the wind distribution, which characterises the wind availability and nature at a given location (Shu et al., 2015). These parameters are sufficient to provide a quantitative assessment of the available wind resource and the potential electrical power output likely to be converted by a wind turbine at any given site. These key attributes of the Weibull distribution function are determined using a wide range of statistical analysis among which the graphical, maximum likelihood, empirical, power density methods have widely been adopted (Bilir et al., 2015; Mohammadi et al., 2016). The adoption and application of the Weibull distribution function in the calculation and analysis of wind power density in this thesis is influenced by its simplicity, flexibility, adaptability and favourable capability to fit wind data for the different sites being assessed (Arslan et al., 2014).

The Weibull distribution function (pdf) can be expressed mathematically in two parameter model as illustrated in equation 3.7 (Liu et al., 2011);

$$f(v) = \frac{dF(V)}{dv} = \left(\frac{k}{c}\right)\left(\frac{v}{c}\right)^{k-1} \times e^{\left(\frac{v}{c}\right)^{k}} \tag{3.7}$$

Where, *v* is the wind speed in m/s, k>0 is the dimensionless shape parameter, and c>0 is the scale parameter with the same unit as wind speed (m/s).

On the other hand, the Weibull cumulative distribution function (cdf) can be expressed using equation 3.8 (Ahmed Shata & Hanitsch, 2006);

$$F(v) = 1 - exp\left(\left(\frac{v}{c}\right)^{k}\right) \tag{3.8}$$

For the purpose of this thesis, the values of k and c have been estimated based on the Maximum likelihood method (ML) and are estimated based on equation 3.9 and 3.10 (Chang et al., 2015);

$$k = \left(\frac{\sum_{i=1}^{n} V_i^k \mathrm{In}(\mathrm{V}_i)}{\sum_{i=1}^{n} \mathrm{V}_I^K} - \frac{\sum_{i=1}^{\mathrm{n}} \mathrm{In}(\mathrm{V_i})}{n}\right)^{-1}, \tag{3.9}$$

$$c = \left(\frac{1}{n}\sum_{i=1}^{n} V_i^k\right)^{\frac{1}{k}} \tag{3.10}$$

Where V_i is the wind speed in time stage, *i* and *n* is the number of non-zero wind speed data points.

The actual wind power density estimated on the basis of the Weibull density function is calculated using the equation 3.11 (Olaofe & Folly, 2013);

$$P_A = \frac{1}{2}\rho(h)\int_0^{\infty} v^3 f(v)dv \tag{3.11}$$

Where P_A is the actual wind power density in terms of its wind distribution, *v* is the wind speed of moving air (m/s), *f (v)* is the wind distribution derived from the Weibull distribution function.

3.3.7.2 Wind energy estimation

Equations 3.12, 3.13, 3.14, 3.15 and 3.16 have been adopted in this thesis to evaluate the electrical power output from the offshore wind sites shown in Figure 3.6 based on the 8 and 10 MW rated wind turbines.

The wind power (W) that is available for extraction is expressed using equation 3.12 (Olaofe & Folly, 2013);

$$\mathrm{p}(v) = \frac{1}{2}\rho(h)Av^3 \tag{3.12}$$

Where *A* is the turbine swept area (m^2) and *p(v)* is the wind power available for extraction in moving air.

Also incorporated within the wind energy estimation is the rotor efficiency/power coefficient (Cp), which is the ratio between the maximum power obtained from the wind and the total power available from the wind (Wenehenubun et al., 2015). It represents a fraction of the available power that can be harnessed from the wind flowing across the wind turbine rotor blades. The Betz's Law sets the theoretical maximum wind energy extraction by the rotor blades at 59 % of the total wind flow at any given time. Research by Ntoko (2009) concluded that the maximum operational coefficient of a horizontal-axis wind turbine is about 50 %. Since the power coefficient of wind turbine is not constant (Verma, 2013), this thesis adopts the 50 % value for Cp in calculating the energy output from wind turbines chosen for this analysis. The estimated mechanical efficiency of the turbine represented by η in the turbine power curve equation (3.13) is specified by manufacturers and these estimates (90 and 94 %) are used for the 8 and 10 MW turbines to assess the power output from the wind farm sites selected for this study (MHI Vestas Offshore Wind, 2014; AMSC, 2012). The power output of the wind turbines (WTs) based on the turbine power curve is expressed in equation 3.13 (Olaofe & Folly, 2013):

$$P(v) = \frac{1}{2}\rho A C_p \eta v^3 \qquad 3.13$$

Where P(v) is the electrical power output of the WTs, ρ is the constant air density (1.225kg/m^3) and $\boldsymbol{\eta}$ is the estimate efficiency of the WTs.

The rated power of the wind turbines selected for this analysis is based on the assumption that the future technological progress of wind energy in the 2020 and 2030 could be defined by a 8 and 10 MW power rated turbines, respectively (EEA, 2009). The electrical power output from wind turbines is estimated based on either the site power curve (statistical technique) or the turbine power curve (direct method) (Olaofe & Folly, 2013) which is expressed in equation 3.13. In the absence of data to assess the time varying air density, one of the key inputs in the statistical technique for calculating turbine power output, this thesis adopts the turbine power curve method which uses the site wind speed, constant air density and the turbine parameters to calculate the electrical energy output from a wind turbine as projected in equation 3.14 (Olaofe & Folly 2013);

$$P(v) = \frac{1}{2}\rho ACp\eta \int_0^\infty v^3\, f(v) dv \qquad (3.14)$$

Where P(v) is the electrical output of the WTs, ρ is the constant air density (1.225kg/m^3, A is the turbine swept area (m^2), Cp is the rotor efficiency, η is the estimated technical efficiency of the WTs determined by turbine manufacturers, *f(v)* is the wind distribution derived from the actual Weibull distribution function.

Also, the capacity factor of wind turbines, which is the ratio of the average power output of the turbine over a period of time to its power output at its rated capacity (Olaofe & Folly, 2013) is considered in the energy analysis outlined in this thesis. The annual full-load hours, which represent the number of hours during which a wind turbine would have to run at full power to produce its energy yield (Salvacao & Guedes Soares, 2015) is applied in calculating the capacity factor. The full load hours for offshore wind adopted in this thesis is 3267.5 hours a year based on the offshore wind performance in 2015

(DECC, 2015e). A 10 % downtime (Salvacao & Guedes Soares, 2015) is deducted from the projected full load hours to account for the time required time for maintenance and other factors that can reduce the wind turbine availability. Ultimately, the capacity factor for offshore wind derived from equation 3.15 or 3.16 is used to assess the electricity generation outlay from wind vis-à-vis dispatchable generation from gas. Based on the patterns of electricity generation from wind, the contribution from standby gas generation can be ascertained in order to assess the impact of intermittent wind generation on cumulative carbon emissions and the cost implications of using standby gas generation plants.

$$C_f = \frac{P_{av}}{P_r} \times 100\% \tag{3.15}$$

$$C_f = \frac{E_0}{P_r * N_d * N_h} \times 100\% \tag{3.16}$$

Where P_{av} is average electrical output over a period of time t, and P_r is the electrical power output at rated capacity, E_0 is the energy output of wind turbine over time t, N_d is the number of working days of wind turbine, N_h is the number of hours a day (hrs/day) in equations 3.15 and 3.16.

3.3.8 Dealing with uncertainty in the energy scenario discourse

The range of assumptions used in this modelling environment are designed to develop a diversified least-cost and emission abatement electricity generating portfolio for the UK 2050 future. However, the construction of such futures is usually fraught with uncertainty, particularly with regards to the development and deployment of emerging technologies, fuel resource availability and prices as well as the dynamics of energy and climate change related policies. In order to enhance the credibility of the scenario outputs from the EOC, a sensitivity study is performed focused mainly on the technology, carbon and fuel cost inputs which have a potential to impact on the quality of scenario outcomes projected over long-term periods. The uncertainty over future primary energy prices is likely to impact on technologies that use fossil fuel, and hence the sensitivity analysis in this case would tend to focus on increasing or decreasing the future cost so that the future energy outlook developed by the model mirrors the volatility of fuel prices anticipated based on the different assumptions made. Therefore, the sensitivity study on coal and gas used in unabated and CCS retrofitted plants would allow the model to determine the proportion of generation capacity that could be added in the mix relative to the costs.

Fluctuations in the price of carbon for both the EU ETS and CPS could pose a significant impact on the reliability of long-term energy projections, especially from predictive models like the EOC. The current UK carbon price floor (CPF) has been projected to 2030 (DECC, 2014c) with a central estimate expected to be £76.66/tCO_2e. However, the government has capped the carbon price at £18/tCO_2e from 2016 to 2020 (HM Treasury, 2014), which is a significant reduction from the original £30/tCO2e target set for 2020. The outlook for the future carbon price post 2020 is both contentious and uncertain, and hence the need for a sensitivity study to assess alternative scenario outcomes that take into account the uncertainty over future carbon prices. This source of uncertainty has a greater potential to impact on the proportion of unabated fossil fuel generation in the mix in the period after 2020.

Likewise, the future technology cost and characteristics of both mature and emerging technologies present another area of uncertainty in the development of low-carbon energy pathways. A high penetration of nuclear, offshore wind and CCS is a prerequisite in effecting deep cuts in carbon emission for low-carbon energy future development. The impact of cost variations on these technologies can affect their rollout within the generation mix. It is of great significance that a sensitivity study targeting the investment cost is performed in order to ascertain the validity of the model outcomes at the backdrop of unforeseeable events in the investment climate. Thus, an independent technology cost variation by +/-30 % provides the scope through which the impact of investment uncertainty over a given period can be assessed.

3.3.9 Model test: Part 1

Apart from being used to generate results for the report: ‘Halving global CO2 by 2050’ the EOC has never been tested or audited to determine its robustness in modelling energy systems. While the model has so far produced outputs that have been used to produce two journal publications (Sithole et al., 2015; Sithole et al., 2016), it is imperative for the purpose of this thesis that model test analysis is carried out to establish whether the model can develop a least cost electricity generation scenarios that can abate GHG emissions and meet energy demand.

The model is built on a Visual Basic program that allows for the development of a least-cost electricity generation mix based on a set of input parameters, and thus reflecting on the current developments impacting the electricity supply sector. The model assessment is carried out based on the 1998 data. There is no specific significance attached to the period selected for this assessment as the main aim is to assess whether the model can develop an optimal generation mix based on both costs and emissions. The data used includes the technology costs, electricity demand, emissions achieved by the electricity sector and fuel cost among other things. An optimised baseline mix is generated for the 1998 period. The technology cost data, that is, the capital, operation and maintenance was derived from the MARKAL "List of Electricity and Heat Generation Technologies – 2010" (Kannan et al., 2010) which was modified to provide theoretical inputs for the purpose of this testing process. The fuel cost for the different technologies is also based on real data (DECC, 2014a) and is also modified in order to fulfil the testing requirements set. The carbon emissions and electricity demand targets used represent the real data for the 1998 period based on (National Atmospheric Emissions Inventory, 2014; DUKES, 2014). Also, it is worth noting that other input variables such as capacity factors and the technology mix used mirrors the actual electricity generation performance in 1998. Thus, the baseline mix mirrors these input characteristics and it represents an optimal generation mix that achieves the emission target and electricity demand set.

Having established the baseline mix, the next stage of the model testing process involves increasing the capital investment, operation and maintenance and fuel costs of one technology at a time while the cost and other input variables for the rest of the other technologies are kept constant to the baseline level. The model simulations are carried out repeatedly until all the nine technologies within the mix are completed. The model test analysis seeks to:

i. Establish the level of decrease in installed capacity for the technology affected by cost increase and then explain why the model reduced the capacity to a given level

ii. Assess the pattern at which the model assembles the generation mix based on cost and emissions abatement approach to compensate for the loss in capacity. Given the level of capacity variations for the technologies developed by the model to meet the targets set, the focus turns to the evaluation of the role of emission factors, costs, constraint system and build-up rates in influencing the operation of the model.

Thus, the generation mix developed after each simulation is analysed in order to identify and justify any changes in the technology mix in the new scenario resulting from cost variations applied. The correlation between the LCOE and the percentage installed capacity for each scenario is established.

3.3.9.1 Expensive Gas CCGT

After increasing the generation cost of gas CCGT, the LCOE reaches 9p/kWh and thereby reducing its installed capacity by 7.6 GW. The installed capacity is reduced from a baseline capacity of 24.9 GW to 17.3 GW in response to an increase in costs for gas plants. Any increase in cost for gas generation plants can only reduce capacity to the level shown in Figure 3.7 and this is mainly because of the minimum capacity that has been fixed within the model as a safeguard to security of electricity supply purposes. However, in response to a 7.6 GW reduction in gas capacity, there is an increase in capacity in all other technologies with coal increasing by 9.7 GW as highlighted in Figure 3.7. This is mainly due to the fact that the other cheaper (1-2p/kWh) technologies such as hydroelectricity, nuclear, biomass, and Combined Heat and Power (CHP) with lower emission factors have been built to their maximum capacity (installation limit) set in the model.

Furthermore, the higher emission target set, allows more coal uptake in the mix despite its high emission intensity. In order to meet the electricity demand, the model also builds more capacity from technologies with slightly higher LCOE (3p/kWh and 5p/kWh), such as onshore wind, oil and pumped storage, respectively, as shown in Figure 3.7. The way the generation mix changes after gas plant costs are increased highlight the fundamental character of the model which allows its optimisation function to select the generation mix based on a least-cost and emission abatement criterion. Furthermore, the analysis highlights the role of the constraint system set in the model which determines the level of capacity that can be built from each technology in line with the electricity demand and emission target set.

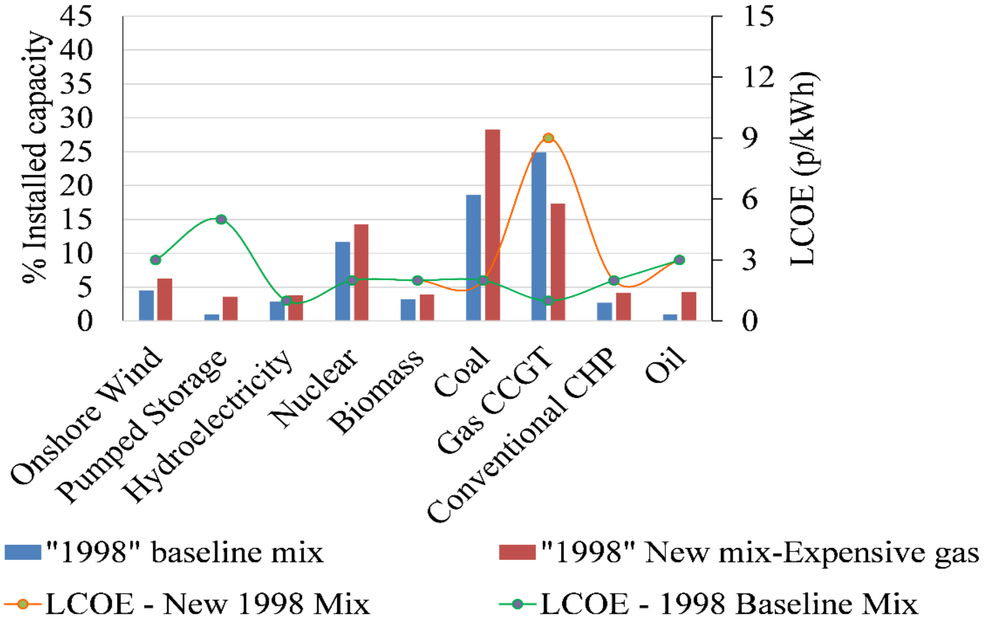

Figure 3.7. The generation mix developed after increasing gas CCGT costs.

3.3.9.2 Expensive Coal generation

At 10p/kWh, coal plant installation is reduced from a baseline capacity of 18.6 GW to 12.1 GW, a decline of the order of 6.5 GW. The high cost of electricity generation contributes in reducing the coal capacity built by the model. Under normal circumstances, the prohibitive costs and higher emission intensity could have seen even lower penetration of coal in the mix, but the annual build rate of 1.2GW/y, a 316.9 TWh electricity demand and a considerably higher emission target of 156 $MtCO_2e$ allow the model to build 12.1 GW in response to an increase in costs. Gas plants have the least LCOE at 1p/kWh, hence, the model builds gas CCGT up to the maximum installation limit of 25 GW set as indicated in Figure 3.8. The combined capacity of coal and gas of 37 GW contribute significantly in achieving the energy demand set and as a result, there is less capacities being added to the baseline mix to achieve the electricity demand target set. This is demonstrated by the electricity generation from hydroelectricity plants which have the cheapest LCOE (1p/kWh), but yet their capacity is only increased by just 0.3 GW. A capacity increase ranging from 1 to 3.3 GW is added to technologies with the highest LCOE (onshore wind, pumped storage and oil) and this is down to the build-up rates apportioned to the respective technologies.

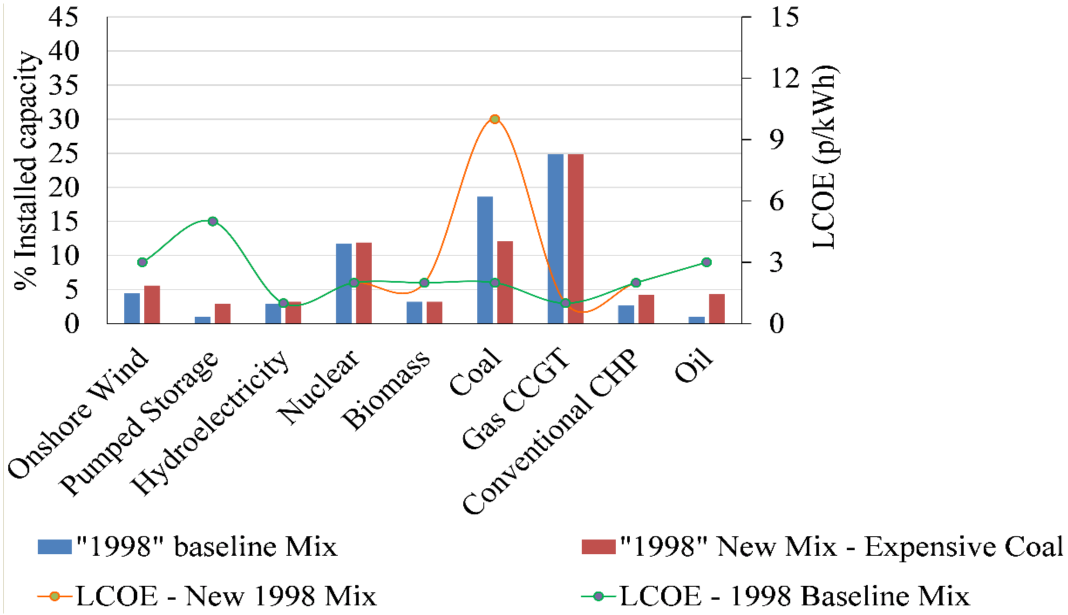

Figure 3.8. The generation mix developed after increasing coal generation cost.

3.3.9.3 Expensive nuclear power

Increasing the cost of nuclear electricity generation by 9p/kWh results in its installed capacity dropping from 11.7 GW to 7.2 GW, which is 38 % decline from the baseline capacity. As the nuclear energy capacity is reduced, gas and hydroelectricity plants' installed capacity is built to maximum installation limit, that is, the possible maximum capacity that the model can build as they offer the cheapest LCOE of 1p/kWh as depicted in Figure 3.9. The LCOE of biomass and CHP is 2p/kWh and the model builds biomass plant up to the installation limit while CHP doesn't reach the maximum installed limit due to the its relatively higher emission factor compared to biomass plants. Coal plants also generate electricity at 2p/kWh, but capacity is increased by 1.8 GW following the fall in nuclear energy installed capacity. The model could only achieve this increase in capacity due to the high emission intensity associated with coal fuel resources. The high cost of generation in onshore wind accounts for 1.8 GW increase in capacity added by the model to the generation mix. A capacity of 2.6 GW of pumped storage is added to the mix compared to the 0.9 GW added to oil despite the marked difference in the LCOE as highlighted in Figure 3.9. The model opts for lower emission pump storage at the expense of cheaper, but polluting oil in its optimisation operation. This is a classic feature of the model where a low-carbon characteristic of a technology supersedes the costs. Again the model has demonstrated its capacity to assemble technologies based on the cost and emission intensity characteristics.

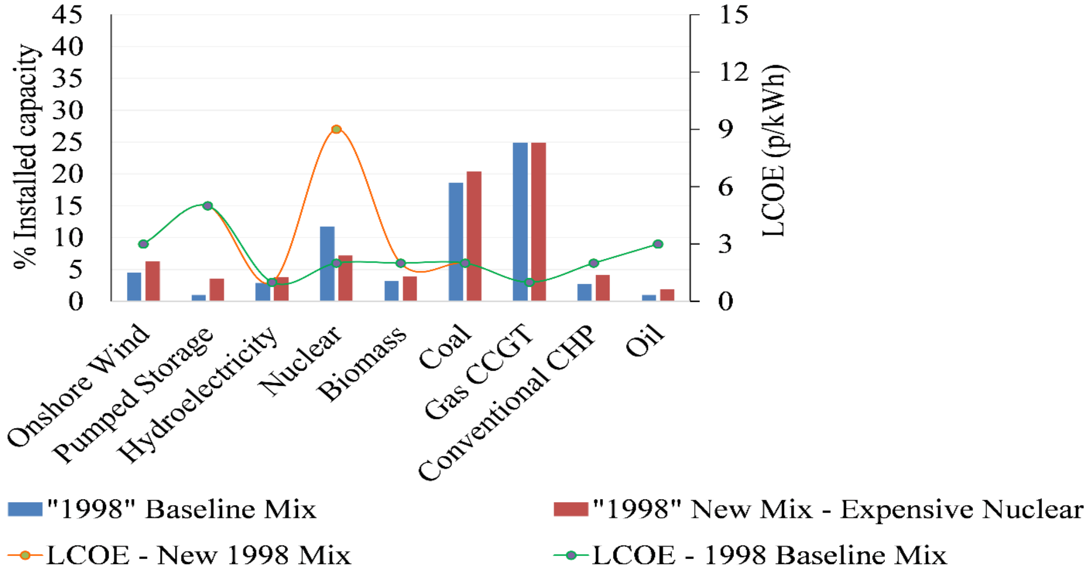

Figure 3.9. The generation mix developed after nuclear plant costs are increased.

3.3.9.4 Expensive pumped storage

Before the cost of generating electricity from pumped storage was increased, its LCOE was pegged at 5p/kWh which was relatively higher than that of the other technologies within the generation mix. When the generation cost for pumped storage is increased to 8p/kWh the model avoids building any capacity from this technology. To this end, the model retains a 1 GW capacity for pumped storage, which is the minimum installed capacity that is set in the model for all the technologies within the mix. An increase in LCOE of pumped storage has no impact to generation mix as the baseline capacities are retained by the model for each of the technologies as depicted in Figure 3.10. The electricity generation output remains dominated by gas CCGT, coal and nuclear energy to meet the 316 TWh electricity demand under the 156 $MtCO_2e$ emission target set in the model.

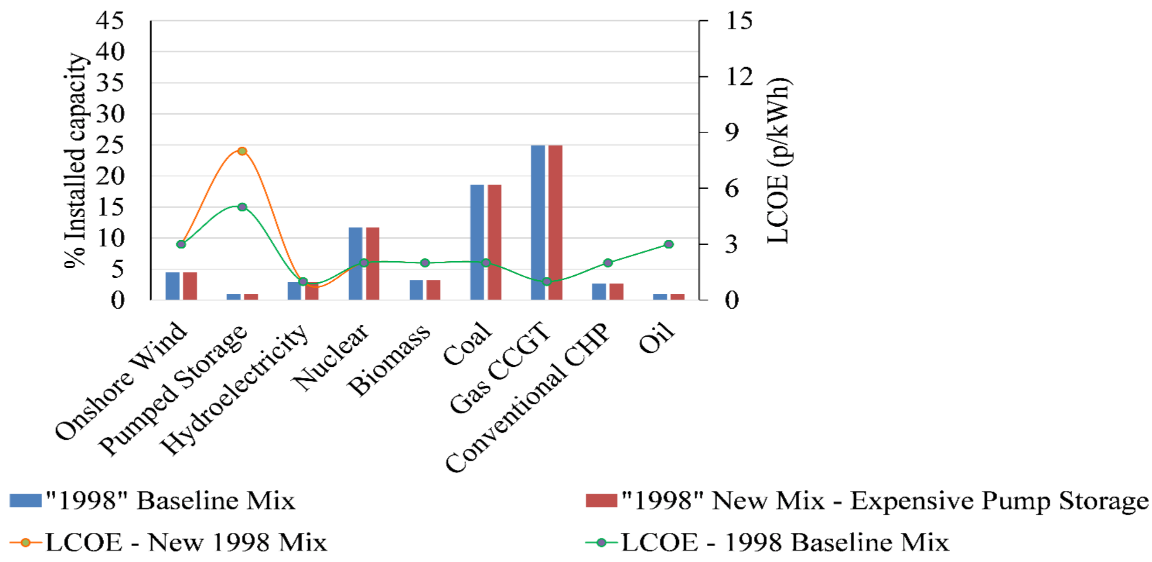

Figure 3.10. The generation mix developed after increasing pumped storage costs.

3.3.9.5 Expensive onshore wind

Onshore wind capacity drops from 4.5 GW to 1 GW when the generation cost is increased to 7p/kWh as displayed in Figure 3.11. Due to the higher LCOE, pumped storage retains the minimum baseline capacity of 1 GW as the model chooses the generation mix based on the least-cost algorithm. Gas CCGT capacity is built to the maximum installation limit as one of the cheapest technologies available. Hydroelectricity and biomass retains their baseline installed capacity which is built to achieve the maximum installed capacity as shown in Figure 3.11. Following the decrease in onshore wind capacity, coal fired generation capacity increases by 2.I GW as it is relatively cheaper at 2p/kWh. The high build-up rate of 1.2GW/y and emission target of 156 MtCO_2e set in the model necessitates this capacity to be added from high emission coal as gas has reached its maximum installed capacity of 25 GW set in the model. Nuclear energy is only built to 11.4 GW, which is about 0.3 GW capacity decline from the baseline scenario. This is influenced by its lower build-up rate of 0.5GW/y which allows the model to add more capacity from other technologies with a higher build-up rate instead. Based on this model operation, generation capacity from oil increases by 1 GW owing to its 1.2 GW penetration rate despite its higher emission factor and LCOE (3p/kWh). Conventional CHP increases capacity by 0.4 GW to reach 3.1, GW which is the maximum capacity that the model can add to the mix to ameliorate the capacity deficit created after the build-up capacity of onshore wind into the mix is reduced. Once gain the penetration of pumped storage into the mix is curtailed due to its higher LCOE, which is set at 5p/kWh relative to the other technologies.

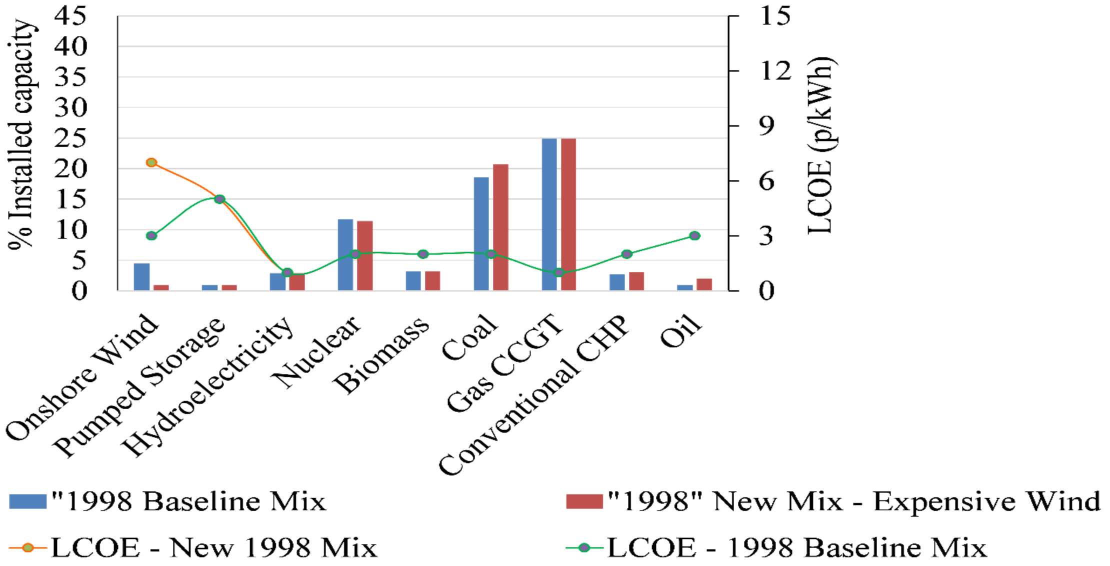

Figure 3.11. The generation mix developed after increasing onshore wind costs.

3.3.9.6 Expensive biomass

Biomass installed capacity is reduced to 1 GW when its generation cost is increased relative to the other technologies. An increase in biomass LCOE to 7p/kWh result in the model building gas CCGT and hydroelectricity plants to the maximum installation capacity limit possible as they have the least LCOE (1p/kWh) as shown in Figure 3.12. Hydroelectricity increases its installed capacity to 3.2 GW while gas CCGT retains the baseline capacity of 25 GW, which is the maximum the model can build. Coal, onshore wind and oil respectively experience the highest capacity increase comparative to other technologies, that is, 1, 1.1 and 1.5 GW in response to the constrained biomass capacity. Oil and onshore wind have a higher build-up rate of 1.2GW/y and based on this, the model builds more capacity compared to other technologies that may be cheaper and with very low carbon emission factors. The difference in capacity added to the generation mix between onshore wind and oil is influenced by a higher emission factor of 650 gCO_2/kWh for oil which allows the model to add more onshore wind than oil in the mix. Coal is cheaper (2p/kWh) and has a high build-up rate (1.2GW/y, and this combined with a higher emission and electricity demand target set, explains the increase in capacity relative to the other technologies. Nuclear energy and CHP capacities increase by 0.3 to 0.4 GW, respectively. Despite its lower emission factor and cost, the level of nuclear energy capacity added to the mix remains very low and this is mainly due to its low build rate while CHP has been built to a level close to the installation constraint limit. Generation capacity for pumped storage is retained at a minimum level due to the higher LCOE which was set at 5p/kWh which results in it being avoided during the selection process. Again, the optimisation process demonstrated by the model displays a pattern where technologies are selected based on costs, emission factors and model constraints which comes into force to influence the manner in which the generation mix is assembled.

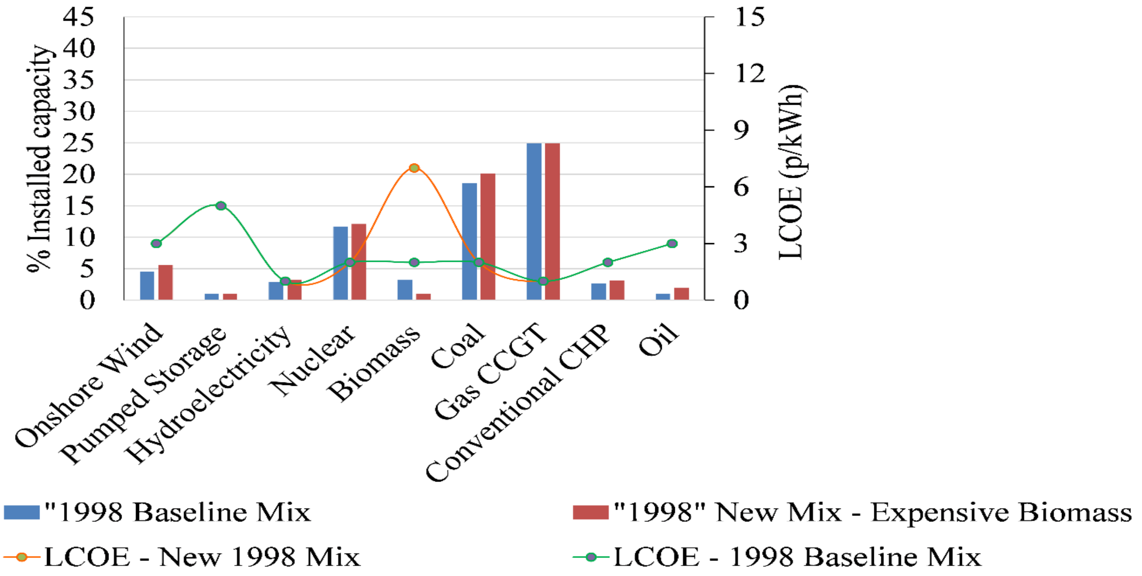

Figure 3.12. The generation mix developed after increasing biomass costs.

3.3.9.7 Expensive Conventional CHP

Increasing the LCOE for CHP to 11p/kWh results in capacity being retained to the minimum level as the model avoids it in its technology selection process. As a result of the increase in CHP cost of generation, a total of 1.7 GW is lost from the generation mix. Biomass, gas and hydroelectricity plants are built to the maximum installation limit as highlighted in Figure 3.13. Coal capacity is increased by 1 GW as it is relatively cheaper and has a higher build-up rate. The build-up rate of 1.2GW/y allocated for oil and onshore wind accounts for the 0.5 GW increase in installed capacity added to each technology. On the other hand, nuclear power generation capacity is built and retained to the baseline level which is the maximum capacity that the model could add to the generation mix considering its lower build-up rate of 0.5GW/y. As is in other scenarios, the build-up capacity in pumped storage is maintained at the minimum level due to the higher generation cost which makes it an unfavourable option in developing a minimum cost generation mix.

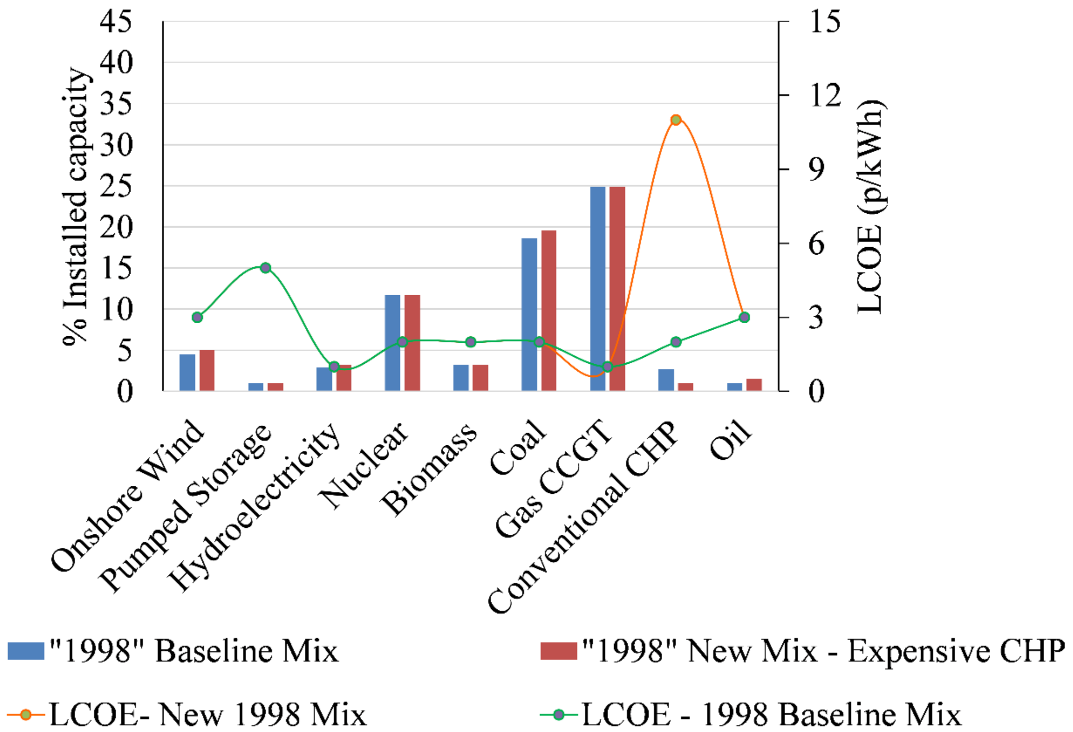

Figure 3.13. The generation mix developed after increasing Conventional CHP costs.

3.3.9.8 Expensive hydroelectricity generation

Increasing the cost of operating hydroelectricity plants by about 10p/kWh reduces the installed capacity to a minimum of 1 GW that the model can add to the mix. Similarly, the high levelised cost of generation in pumped storage of 5p/kWh reduces its contribution to the generation mix to about 1 GW as shown in Figure 3.14. The model builds gas CCGT plants to maximum installation limit as they have the cheapest LCOE at 1p/kWh. At 2p/kWh and 1.3 GW/y build rate, biomass is built to the maximum installation constraint limit. On the other hand, nuclear power capacity is retained to its baseline level of 11.7 GW which is the maximum capacity that the model could build at a build rate of 0.5GW/y. Despite its higher emission intensity, a LCOE of 2p/kWh and a build rate of 1.2GW/y, the coal installed capacity is increased by 1 GW to reach a total capacity of 19.6 GW. Oil and onshore wind have relatively higher cost of electricity generation which is set at 3p/kWh, hence the model only allows a 0.5 GW capacity uptake from these technologies owing to their 1.2GW/y build rates. The uptake of the generation capacity from higher cost technologies such as oil and onshore wind is necessitated by the requirement to meet the electricity demand and the emission constraint targets set in the model.

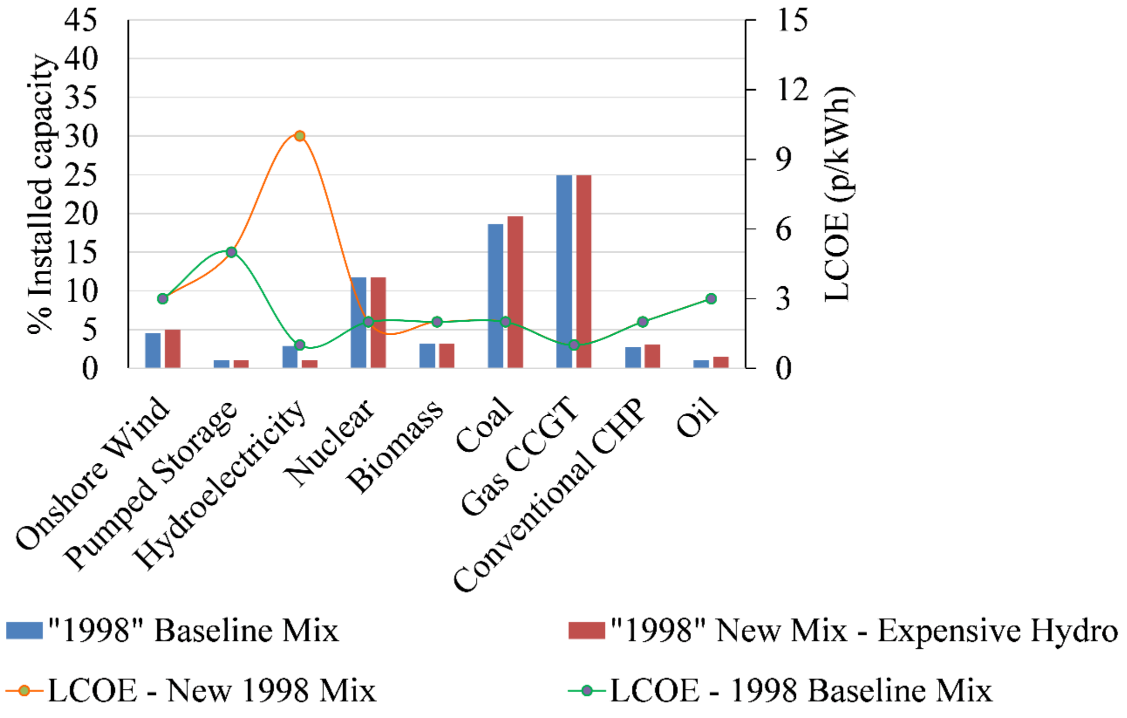

Figure 3.14. The generation mix developed after incresing hydroelectricity plant costs.

3.3.9.9 Expensive oil-fired generation

When the LCOE generated from oil fired plants is increased to 10p/kWh, the model only builds the minimum possible capacity of 1 GW from this technology due to the high cost. Initially, oil generation was limited to a minimum capacity owing to its higher emission factor of 650 gCO_2kWh and a relatively higher LCOE which is set at 3p/kWh. Since the installed capacity for oil generation is retained at I GW baseline level, it implies that contribution from the rest of the generation technologies within the mix remain unchanged as illustrated in Figure 3.15. The baseline technology mix retained by the model following the increase in the cost of electricity from oil achieves the 156 $MtCO_2e$ emissions target and the 316 TWh electricity demand set.

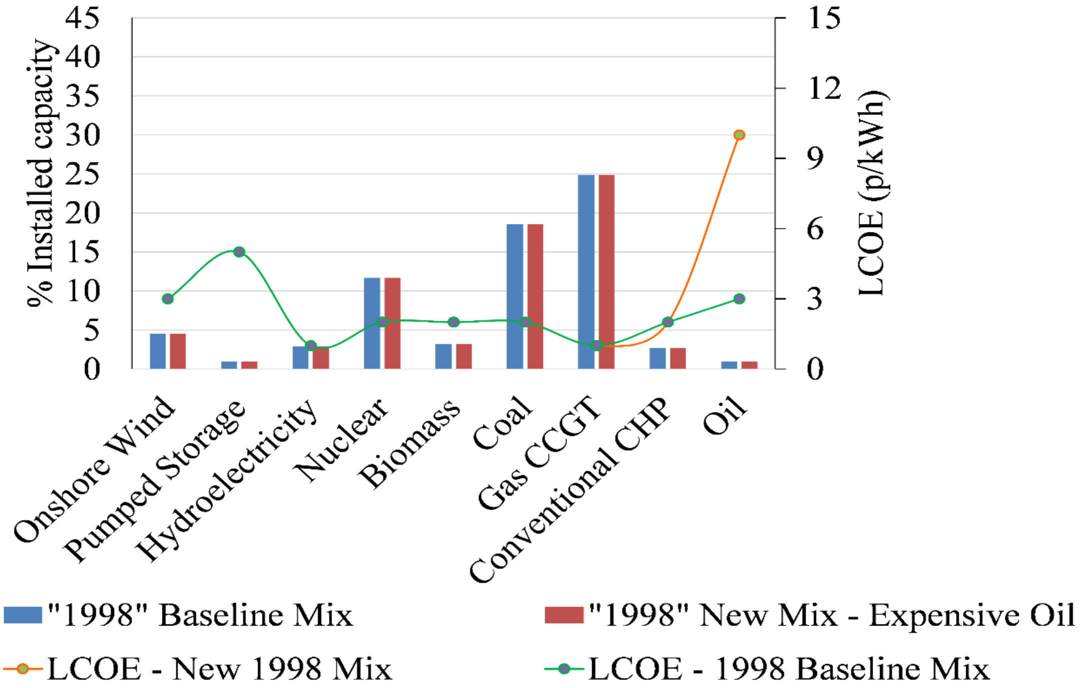

Figure 3.15. The generation mix developed after increasing oil fired plant costs.

3.3.10 Model test: Part 2

The low-carbon electricity generation mix for the 2050 future developed by the EOC is compared against the Central Coordination transition pathway developed by the FESA model (Barnacle et al., 2013). The energy scenario outputs from the EOC reflects on the development of the UK energy policy while the Central Coordination pathway envisions increased government control and regulation in developing a low-carbon, secure and affordable energy system (Barnacle et al., 2013). The electricity generation mix for the Central Coordination pathway is projected to reflect the 2020, 2035 and 2050 outlook, and hence the technology mix output from the EOC is developed to mirror the same period.

Figure 3.16 portrays the technology mix for the two energy scenarios in 2020. Central Coordination pathway has a higher deployment outlay of unabated coal and low-carbon (nuclear and coal CCS) generation capacity compared to the scenario output from the EOC. Unabated coal and CHP in Central coordination installed capacity is 6.4 and 3.5 GW higher than the deployment outlay in the EOC as shown in Figure 3.16. The respective installed capacity for nuclear and coal CCS in Central Coordination is 12.2 and 2 GW compared to 10 and 0.4 GW in the EOC scenario. There is a 0.6 GW difference in installed capacity in unabated gas generation between the two scenarios as shown in

Figure 3.16. There is a higher penetration of renewable energy technologies in the EOC scenario compared to the Central Coordination pathway (see Figure 3.16). The level of deployment of offshore wind, solar PV and biomass the EOC scenario respectively increase by 7, 2 and 8 GW against the projections in Central Coordination pathway as illustrated in Figure 3.16.

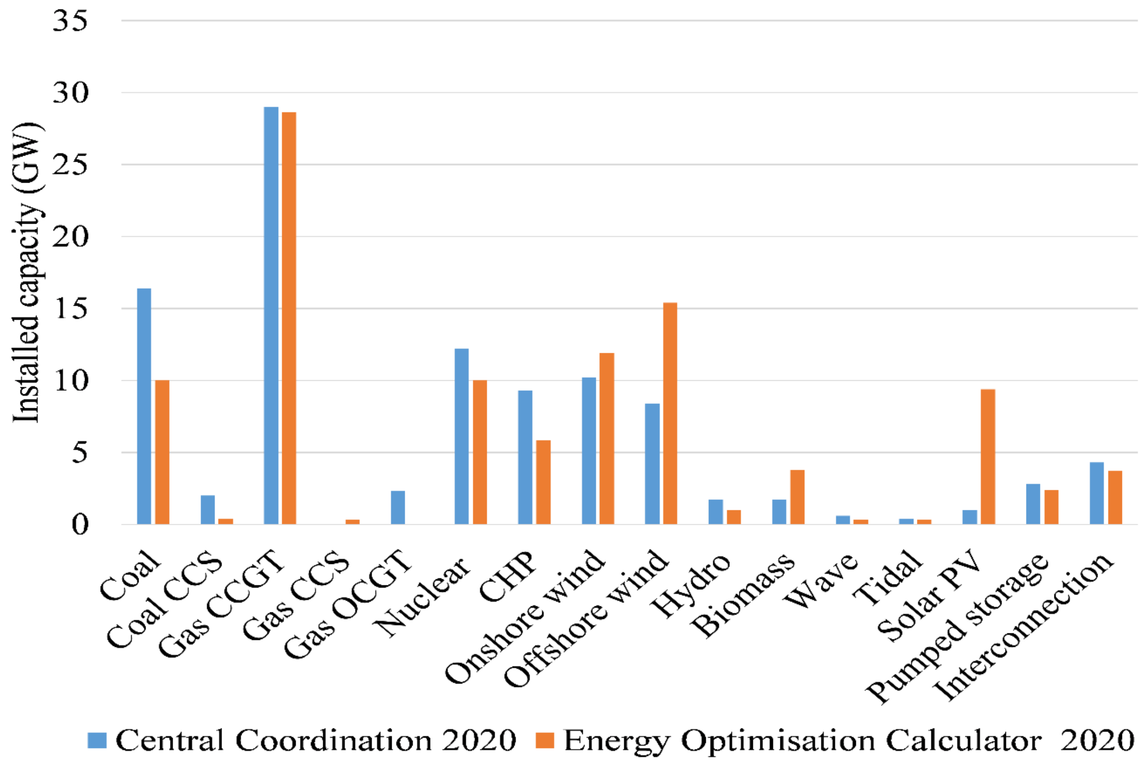

Figure 3.16. Comparison of the generation mix of the two pathways in 2020

The generation mix portrayed in the EOC scenario presents a least cost and emission abatement pathway. A low deployment outlay of carbon intensive unabated coal in the generation mix is commensurate with emission abatement target set in the model. Both scenarios have a high penetration of unabated gas in the mix, however, the projection in the EOC scenario is developed on the basis of it being the cheapest technology as well as less carbon intensive compared to unabated coal. Also, the technology selection based on cost is demonstrated by the constrained deployment of pumped storage, hydro and interconnection in EOC scenario compared to Central Coordination. Similarly, a high penetration of renewable energy technologies (see Figure 3.16) is developed in line with the objective of meeting the emission target set in the model. Low-carbon technologies such as nuclear, and CCS as well as other emerging technologies such as wave and tidal have lower deployment projections in the EOC scenario compared to the Central

Coordination due to the constraint limit set in the model to reflect the technology development within the electricity generation system.

The UK energy policy, which is reflected by these two scenarios is driven by the objective of developing a low-carbon, secure and affordable electricity system. To this end, costs and technology diversity are important in determining the direction of the energy system development. A modelling framework underpinned by a system of constraints on technology deployment as well as a least-cost and emission abatement approach has a great significance in developing insights for low-carbon electricity generation futures. These factors justifies the adoption of the EOC as the modelling tool for this research.

3.3.11 Summary

Different modelling approaches have been developed to characterise the evolution of the electricity supply infrastructure to a low-carbon future against the energy security and climate change policy objectives. These models have generated an array of scenarios, particularly in the power sector with a view to assessing the costs, trade-offs and pathways related to achieving long-term emission targets and energy security (Strachan et al., 2009). The current modelling frameworks for the electricity generation sector such MARKAL, ESME and the EOC have sought to explore a least-cost technology mix that could be developed and deployed to achieve the emissions and energy security targets. Compared to other energy models, the EOC is less data intensive and it integrates up-to-date policy developments to produce scenarios that reflects on the dynamics affecting the UK electricity generation sector.

The energy models which underpin the current UK energy policy take a whole system approach in assessing the transition of the economy to a low-carbon future. However, scenario developments are limited in addressing the impact of variability of renewable energy technologies on decarbonisation and energy security. Renewable energy technologies along with CCS and nuclear are vital in driving the UK electricity supply sector to a low-carbon future. Given its focus on the electricity generation sector, the EOC addresses this research gap on intermittency by incorporating wind resource analysis in its modelling framework. By so doing the actual contribution of renewable energy technologies, particularly offshore wind to decarbonising the power sector and promotion of energy security is ascertained.

Chapter 4 Security of the UK electricity supply

4.1 Introduction

The security of electricity supply challenge is generally conceptualised on a wide range of timescales focussing mainly on the short, medium and long term risks. The risks to security of electricity supply portrayed in this chapter seek to explore the long-term policy, market and infrastructural influences likely to impact on the UK electricity supply infrastructure, with particular emphasis to 2030. The 2030 milestone is significantly important to the UK electricity supply development as it is considered to be the watershed mark by which the sector is expected to be decarbonised in order to guide the economy to a cost-effective path to the 2050 emission reduction target (CCC, 2013a; CCC, 2015; DECC, 2012g). Also, it is a crucial landmark period for the UK energy economy as it tests the resilience and dynamism of the UK energy systems and policy frameworks to respond and adapt to the challenges of severe capacity erosion due to plant closures as well as the need to link the low-carbon agenda with security of supply.

The security of supply vulnerabilities linked to the UK electricity supply system have long been envisaged in the context of its predominantly fossil fuel based generation. The share of coal and gas electricity generation in 2014 accounted for 60% of the total supply output (DECC, 2015d), which underscores the country's dependency on foreign fossil fuel supply sources. The dominance of the imported fossil fuel in the UK electricity generation system increases the potential for supply disruptions due to strategic risks associated with geopolitical instabilities or lack of investment in overseas supply infrastructure. However, the medium-term risk to the UK security of electricity supply in the period to 2030 is likely to be influenced by domestic system risks induced by the erosion of capacity margins following the anticipated closure of aging coal and nuclear power generation infrastructure as well as the increasing environmental concerns linked to climate change. The UK energy policy has been described as 'inconsistent, incoherent and ineffectual' following the UK government's proposed 'dash for gas' to mitigate the potential energy crunch as aging nuclear and coal plants face closure (The Scottish Governmnet, 2015). The seemingly 'start and stop' approach which apparently characterises the current UK energy policy poses the greatest threat to security of supply as it breeds uncertainty, a development which only succeeds in driving away the investment required to build the low-carbon electricity generation infrastructure that mitigates climate change and security of supply challenges.

The constrained investment climate has made the operation of the existing UK gas generation fleet and the prospective investment in new gas plants uneconomic. As a flexible fuel that adapts well under a wide range of future policy directions, natural gas is likely to play an important role in the global energy mix. While the long-term future of the global gas prices remain highly uncertain, the prospects for new investment in new gas generation infrastructure in the UK electricity generation portfolio remains unknown. The increase in the amount of intermittent renewable energy resources in the generation mix in the period to 2030 is likely to weaken the investment appetite for new gas plants due to the reduction in gas plant operational hours as output from renewables increases. Thus, a new energy policy landscape set to be driven by new gas plants (DECC, 2015a) carries a high risk to security of electricity supply unless the UK government intervenes by incentivising gas generation heavily in order to promote investment.

The phase-out of coal-fired electricity generation earmarked for 2025 could also strengthen the business case for the development of new gas plants as the prospects for profitability in the gas electricity generation sector could be heightened if coal is completely eliminated from the generation mix. A coal phase-out by 2025 could widen the gap between supply and demand if a quick response by government to promote gas, biomass and other fuels is not prioritised within the existing policy. Therefore, clarity and stability in the direction of the energy policy framework is vitally important, least the uncertainty over the future of the existing coal fleet could become another source of risk for the security of energy supply for the UK.

The challenge of guaranteeing security of supply in the UK electricity supply system is becoming more complex as the de-rated capacity margins continue to shrink as a result of continued plant closures. New nuclear power development through the 2020s is projected to increase and combine with the new gas generation fleet to ameliorate any potential energy security risks following the capacity crunch created by the closure of aging coal and nuclear plants. While nuclear energy deployment could certainly provide a secure, baseload source of low-carbon electricity, progress in the development of a fleet of new nuclear plants remains worryingly slow due to the limited number of possible developers as well as the financial and commercial challenges of delivering new nuclear reactor designs. Taking into account the long technical and investment timescales for nuclear plant development, no new plant has yet received a final investment decision. This implies that there is a potential that no new nuclear plant could be commissioned by 2030, thereby putting the electricity delivery system at serious risk. At the backdrop of these security of supply risks, this chapter introduces alternative scenarios to explore the UK security of electricity supply phenomenon in the context of the recently unveiled new UK energy policy (DECC, 2015a) as well as on the assumption that the future dynamics in the energy markets could remain unfavourable for investment in modern gas plants by 2030. Also, attention is focused on how the new UK energy policy could potentially be reframed in order to align the sector and the economy in its entirety with the 2050 emission reduction target. The following sections explore the implications of the technology, investment and decarbonisation uncertainties on the security of electricity supply challenge by 2030.

4.2 The UK new energy policy 'reset'

Concerns over the security of electricity supplies in the UK have prompted the policy-makers to redefine the UK energy policy objectives. As the buffer between supply and demand is projected to continue to ebb away in the midst of plant closures, the UK government is planning an accelerated rollout of new modern gas and nuclear plants through the 2020s to replace the dwindling capacity levels as well as bolster security of supply (DECC, 2015a). The new campaign to fast track the rollout of a fleet of modern gas generation infrastructure is proposed at a time when the investment climate for gas-fired generation remains uneconomic to attract any potential investors due to rising distribution, transmission and operating costs and environmental levies. However, this new gas plant development initiative, which is central to the UK security of supply challenge coincides with the prolonged slump in oil and gas prices which could potentially act as one of incentives that could attract investment to bring forward the new gas plant development aspired by the new UK energy policy. While the UK government remains committed to the 80% greenhouse gas emission reduction target by 2050, the announcement for the potential phase-out schedule for coal by 2025 is set to improve the investment climate for new gas plants. The removal of coal as a competing fossil fuel in the generation mix and the creation of a favourable capacity market mechanisms for gas could reduce the delivery cost for new gas plants, and thus assist in achieving the delivery of between 15 and 30 GW of new gas generation capacity by 2030 as envisaged by the UK government (Aldridge, 2015).

While the phase-out timeline for the current fleet of old coal plants has been determined, there is growing concern that the new fleet of nuclear power plants is not likely to be built to schedule. Contrary to the UK Nuclear Industry's ambition to deploy 16 GW of new nuclear capacity by 2030 (HM Government, 2013b), no FID has been received for the new nuclear capacity which is required to address the capacity crunch created by plant closures through the 2020s. In addition to this, the long planning and building times, coupled with the extremely high capital costs associated with new nuclear projects (Royal Academy of Engineering, 2015) could make it highly unlikely that more than one new nuclear plant is added to the UK generation mix by 2030. The potential stall in new nuclear build through the 2020s could put a dent on the UK decarbonisation aspirations for both its carbon budgetary requirements as well as the 2050 decarbonisation target. The growing concern over the potential delay in the development and deployment of new nuclear power plants by 2030 is further worsened by a report warning that the closure of all existing coal and aging nuclear plants without immediate replacement capacity could leave Britain with a supply gap of 40-55 per cent by 2025 (Institution of Mechanical Engineers, 2016).

Also linked to the new energy policy is the UK government's decision to cancel the £1 billion funding for CCS commercialisation programme (DECC, 2015e). This policy decision effectively implies that the development and deployment of the CCS capability in the UK industry and the electricity sector in particular could be delayed well beyond the initial 2020–2030 projected commercialisation timeline (CCC, 2015; DECC, 2012a; Pöyry, 2013). The absence of CCS in the generation mix by 2030 could compromise the UK decarbonisation aspirations, especially in a scenario where the deployment prospects for new nuclear could be as low as 3.2 GW, the only capacity representing the approved Hinkley Point C nuclear project (DECC, 2014g). The opportunity to use CCS applications in new coal and gas plants by 2030 to boost capacity levels is set to be missed as funding for CCS projects is prematurely withdrawn. The opportunity to ameliorate security of supply threats through the provision of baseload generation from coal, gas and biomass plants retrofitted with CCS capability could be compromised following the UK government decision to cancel funding for CCS programmes.

The future development of renewable energy under the new energy policy landscape remains uncertain, especially with the UK government's decision to end the green subsidies for onshore wind and solar (DECC, 2015f; DECC, 2014d). The tendency by the UK government to frequently change or defer key policy decisions, particularly on low-carbon and renewable energy sources, has become a worrying occurrence within the UK energy policy. This trend has had the impact of weakening investor confidence on a policy framework which could be perceived as inconsistent and lacking the edge to promote a supportive environment for the development and deployment of renewable energy technologies. The UK government's commitment to the development and deployment of offshore wind, which is one of the key technologies expected to drive the security of supply and decarbonisation agenda of the new energy policy (DECC, 2015a), comes with financial strings attached. In unveiling the new direction of the energy policy, the UK government maintained that offshore wind would need to move quickly to cost-competitiveness as no subsidies will be offered to the industry (DECC, 2015a). Thus, the role of offshore wind in the new UK energy policy is dependent on the rate at which it can compete with other renewable technologies within the CfD renewable energy auctions. In the event that the cost of offshore wind falls below the £100/MWh threshold, the UK government envisages that a potential capacity of 10 GW of offshore wind could be deployed through the 2020s (DECC, 2015a). The implications of the new UK energy policy on both security of electricity supply and on electricity sector decarbonisation are analysed in great detail in the following sections.

4.2.1 Energy security and low-carbon electricity sector by 2030; the new UK energy policy

In the context of the new UK energy policy framework described in Section 4.2, an electricity generation mix is developed using the EOC to assess the extent to which it addresses security of supply and decarbonisation objectives by 2030. The input parameters for the technology mix developed in this scenario are determined based on the deployment ambition projected in the new energy policy (DECC, 2015a) for key technologies such as coal, gas, nuclear and offshore wind. As for the other technologies within the mix, the deployment trajectories are drawn from UK energy policy projections.

The capex and opex outlined in Table 3.4 form part of the inputs computed in the model to develop this scenario. Electricity demand for 2030 is set at 344 TWh and as outlined in Table 3.2. In the absence of CCS technology in the generation portfolio coupled with severely constrained new nuclear power plant deployment by 2030, it is unlikely that the the electricity generation could achieve a 100 or 200 g/kWh carbon grid target This unabated gas dominated new UK energy policy generation mix is assessed based on a 81.4 $MtCO_2e$ emission target.

The level of deployment for the technology mix projected in this new energy policy shown in Figure 4.1 is assessed in the context of the investment, policy and other challenges facing the electricity generation sector. Therefore, the penetration of each technology in the generation mix is constrained by cost, emission factors and the technology build up rates set in the model as described in Section 3.3.2. Furthermore, the maximum deployable capacity for each technology is constrained using the physical installation limit and the installation constraint as described in Section 3.3.3 (see also Appendix A1).is determined. As a result, Figure 4.1 presents a least-cost and emission electricity generation mix that meets the targets and conditions that reflect on the outlook of the new UK energy policy by 2030.

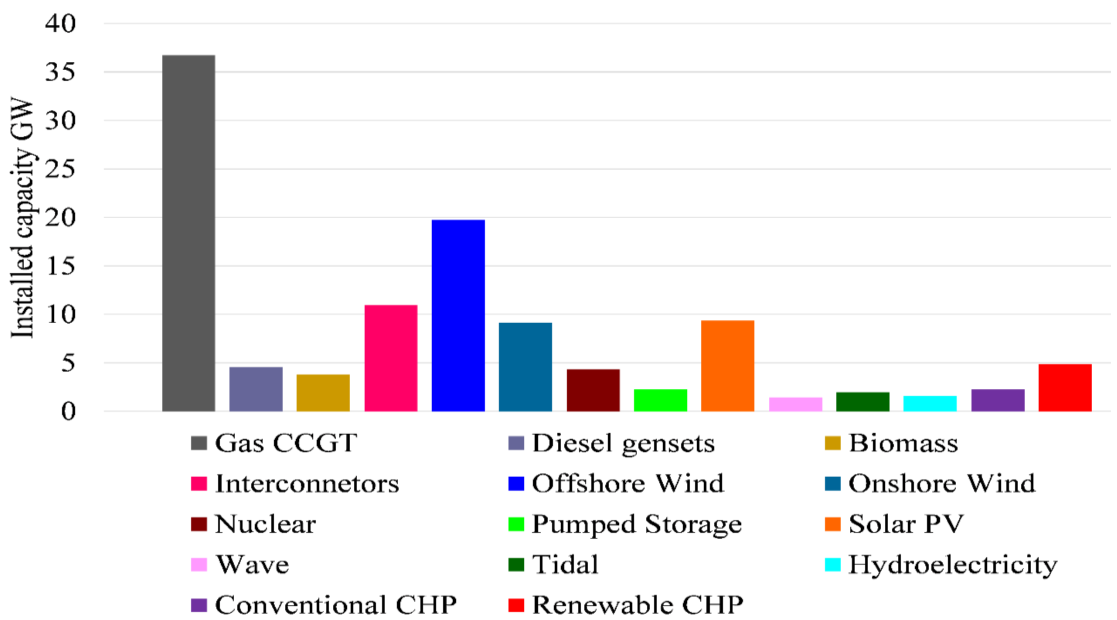

Figure 4.1. The potential installed generation capacity in the context of the new UK energy policy by 2030.

The scenario portrayed in Figure 4.1 shows a generation mix by 2030 following the successful closure of coal and the majority of the aging nuclear plants. The technology diversity assembled in Figure 4.1 is reminiscent of the UK government's planned investment drive to encourage the construction of more gas-fired power plants. According to the Green Alliance (2011), the dash for gas generation of the 1990 was in the UK's national interest, but a second dash for gas portrayed in Figure 4.1, would not be in the UK's long-term interest as it could raise the cost of meeting the nations carbon budgets. It is highly unlikely that a second dash for gas could afford the UK to meet its fourth and fifth carbon budgets earmarked for the 2023-27 and 2028-32 periods. The gas-fired generation deployment illustrated in Figure 4.1 could either lock the UK into higher carbon levels, or result in gas power stations investments of up to £10 billion being retired early or needing costly CCS retrofit if the plants are to be a source of baseload generation (Green Alliance, 2011).

The technology outlay portrayed in Figure 4.1 underscores the first priority given to the security of supply as demonstrated by the dominance of CCGT plant generating capacity in the mix. Assuming that 10 of the current 28.9 GW total CCGT plant installed capacity in the UK electricity generation sector is retired by 2030 (CCC, 2015), 17.8 GW capacity of a fleet of new gas plants is added to the existing generation mix to achieve the 36.7 GW of installed CCGT capacity shown in Figure 4.1. The build-up of the new CCGT plant capacity to the gas generation sector is in line with the 26 GW new gas capacity investment by 2030 which was projected in the Gas Generation Strategy (DECC, 2012c).

The complete phase-out of coal, which is conspicuous by its absence from the generation mix in Figure 4.1, and the stall in the rollout of a fleet of new nuclear power plants could possibly have created ideal conditions for the renaissance in the new gas plant deployment by 2030. The uptake of renewable energy technologies, particularly wind and solar PV portrayed in Figure 4.1 is reflective of industries trying to cope with the reality of thriving in a competitive renewable market as expected by the UK government. The 19.7 GW capacity outlay for offshore wind by 2030, which is illustrated in Figure 4.1, is suggestive of the success of the CfD auctions in driving down the cost of renewable energy. According to the results of the CfDs allocation rounds respectively held in February and December 2015, the final auction price of £119 and £114 per MWh was achieved for offshore wind, which was well below the previously published strike price of £140/MWh (DECC, 2015c; DECC, 2013b), and thus confirming a significant fall in offshore wind costs. The era of increased price competition and the resultant fall in renewable costs is likely to drive diversity in low-carbon energy technologies which are vitally needed to drive down emissions in the electricity generation sector in line with the 80 % emission reduction target by 2050.

The decarbonisation capability of a generation mix dominated by unabated gas as shown in Figure 4.1 is quite debatable regardless of the view that gas is considered to be a cleaner source of energy than coal (DECC, 2012d). In the absence of 'dirty' coal, the combined emissions from gas CCGT plants and diesel generators could make it difficult for this gas driven energy policy to meet the fifth carbon budgetary requirements as prescribed by the CCC. A comparison of the emission performance of the new UK energy policy against the fifth carbon budget emission projections for the electricity generation sector shown in Table 4.1 shows the magnitude of the environmental penalty likely to be incurred as the UK electricity sector is revamped in order to attain the security of supply status. The cumulative carbon grid emissions for the new UK energy policy is 81.4 $MtCO_2e$ which is more than double the 2030 decarbonisation threshold of 31 $MtCO_2e$ projected by the fifth carbon budget assessment (see Table 4.1). The 31 $MtCO_2e$ emission output from the power sector provides an indicative target that could succeed in keeping the UK economy on the cost-effective path to the 2050 target (CCC, 2015).

Table 4.1. The 2030 decarbonisation trajectory of the new UK energy policy mirrored against the fifth carbon budget scenarios (CCC, 2015).

Scenario description	Grid CO_2 intensity (g/kWh)	Emission target by 2030 ($MtCO_2e$)
Fifth Carbon Budget (Central scenario)	100	31
Fifth Carbon Budget ('Barriers' scenario)	116	40
New UK energy policy	236	81.4

The quest for energy sovereignty sought by the new UK energy policy could lead to the development of an electricity supply system with a grid emission intensity of 236 gCO_2/kWh, which is comparative to the low deployment scenario developed by the Royal Academy of Engineering with an emission intensity of 234 gCO_2/kWh by 2030 (Royal Academy of Engineering, 2015). The probability that this new UK energy policy could come short on the decarbonisation target is inevitable, especially in a case where CCS technology is not integrated into the generation mix to mitigate excessive emissions following an increase in the penetration of gas CCGT in the electricity supply system.

Although the diesel reciprocating engines ‘gensets’ could potentially act as peaking plant or augment the potential capacity deficit through the 2020s, the technology is known to be dirtier than coal with a carbon intensity of 1010 gCO_2/kWh (Aldridge, 2015), which is far higher than the 488 gCO_2/kWh (POST, 2011) for unabated CCGT plants. With just 4.3 GW capacity of baseload generation from nuclear (see Figure 4.1), coupled with a considerable high intermittent renewable capacity within the generation mix, diesel ‘gensets’ are operated at 13 % load factors, and thus the new energy policy emission contribution is pegged at 81.4 $MtCO_2e$, which translates to a grid intensity of 236 gCO_2/kWh by 2030 based on the technology mix shown in Figure 4.1.

While the existing domestic and regional policies, such as the EPS and IED, designed to penalise heavy polluters apply on installations above 50 MW (European Council, 2010; DECC, 2012c), this means that this threshold would not apply or affect diesel generator units. Therefore, the implications of a non-regulated diesel generator industry on electricity sector decarbonisation is catastrophic, especially if the economic environment for gas generation becomes constrained in any way or time in 2030. Under these circumstances, the proliferation of diesel ‘gensets’ which to some extent could be spurred by the low capital cost (Aldridge, 2015), could increase the risk of failure to achieve any decarbonisation target, even the 80 % economy-wide greenhouse gas emission target by 2050. In any case, a carbon intensive electricity supply sector by 2030 is diametrically opposed to the decarbonisation rhetoric espoused by the Climate Change Act. The proliferation of these dirty ‘gensets’ and unabated gas CCGT plants would not be supported by the CCC who have consistently advocated for all forms of fossil fuel-fired generation to be fitted with CCS technology with the remainder of the unabated gas-fired plants providing back-up to intermittent energy sources. The presence and frequent operation of unabated coal and diesel fired generation in the mix by 2030 could undoubtedly increase carbon emissions, and thus endangering the carbon budgets.

The closure of the aging coal and nuclear generating plants across the UK through the 2020s would require the development of an electricity system that can respond to changes in the generating output. The UK government plans to provide secure and affordable electricity supplies for the future through the construction of new nuclear, gas and offshore wind. In bringing this plan to fruition, the UK government would need to take advantage of an integrated European Union energy markets through interconnectors to supplement and balance intermittent electricity from renewable sources. Currently the UK interconnector capacity stands at 4 GW, which is about 4% of the installed capacity (Ofgem, 2014). The interconnector capacity outlay of 10.9 GW shown in Figure 4.1 demonstrates the UK government's commitment to access sustainable sources of electricity generation across EU energy markets, and thus assisting in mitigating and improving security of supply challenges.

The increase in interconnectors in the electricity supply mix by 2030 as shown in Figures 4.1 and Table 4.2 could be driven by the UK government's decision to allow the supply system to participate in the capacity market auctions. Furthermore, the UK policymakers are keen to develop the country's interconnector network in line with the EU target of 10 % and 15 % of generation capacity to constitute interconnection by 2020 and 2030, respectively, (DECC, 2015e; European Comission, 2015). The interconnector development portrayed in Figure 4.1 equates to about 9.8 % of installed capacity by 2030, assuming that most of the planned interconnector projects tabulated in Table 4.2 are carried through to commissioning dates planned by developers.

Table 4.2. Existing and future UK interconnectors to be integrated in the electricity supply mix by 2030 (Ofgem, 2014).

Project Name	Connecting Country	Capacity (MW)	Delivery/Estimated delivery date
IFA	France	2000	1986
Moyle	Ireland	500	2002
BritNed	Netherlands	1000	2011
EWIC	Ireland	500	2012
ElecLink	France	1000	2019
NEMO	Belgium	1000	2019
NSN	Norway	1400	2020
FAB Link	France	1400	2022
IFA2	France	1000	2020
Viking	Denmark	1000	2022
Greenlink	Ireland	500	2021

While UK electricity demand is projected to increase to reach between 30% and 100% by 2050 (DECC, 2012b), the electricity generation mix developed through the new UK energy policy could meet the 2030 electricity demand based on the generation distribution displayed in Figure 4.2. The bulk of the 344 TWh electricity demand projected for 2030 (DECC, 2014i) is met by unabated gas which contributes 37% of the demand. An increase in the generation output of 16 %, 14 % and 9 % from offshore wind, interconnectors and nuclear power (see Figure 4.2) implies that the operational regime of gas generation sector is maintained at 41 % capacity factor to produce 130.5 TWh towards the electricity demand target. With over 48 % of the total CCGT installed capacity comprising of new gas plants, it is uncertain whether the implied 41 % capacity factor at which the gas plants are operated in this scenario could be profitable enough to allow investors to recoup the investment laid out for the new gas generation capacity without significant capacity payments.

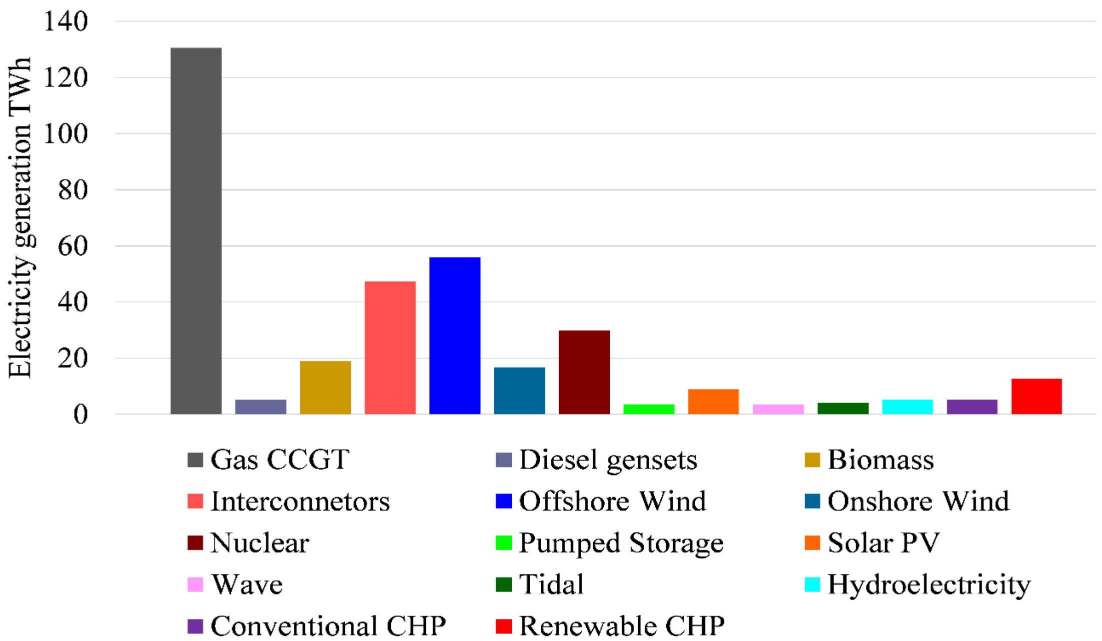

Figure 4.2. Electricity generation output from the new UK energy policy technology outlay by 2030.

The marginal electricity generation contributions from other technology sources such as hydroelectricity and other emerging renewable energy technologies shown in Figure 4.2 could be a welcome development in security of supply terms especially with constrained deployment in nuclear power plants in the generation mix by 2030. However, any increase in electricity supply from other technologies shown in Figure 4.2 could have the effect of reducing the operation regime of unabated gas generation, and thus impacting on the profitability of the gas CCGT plants. The potential profit margins likely to be realised by the gas generation operators through capacity market incentives and the low gas prices could be eroded by the projected carbon price which is likely to be in the region of about £78/tCO_2 by 2030 (DECC,2015j). However, since gas generation is at the centre of the new UK energy policy, the carbon floor price freeze of £18/tCO_2 currently in place till the 2019/20 period (HM Treasury, 2014) could be extended up to 2030 in a bid to lower operational cost for CCGT operators. A policy initiative that uses carbon prices like some form of bait to entice and keep gas operators motivated to invest and support unabated gas generation in the generation mix runs the risk of compromising on some of the major policy objectives. Any attempt to keep carbon prices low in favour of gas generation without policies in place to effect a legal phase-out of coal generation could prove disastrous. This is because such policy could create favourable economic conditions for the continual operation of carbon intensive coal. Such a development would militate against the nation's carbon reduction commitments embodied in the carbon budgets.

4.2.2 New gas plant deployment fails to meet the 2030 target; implications to energy security and low-carbon supply system

This section assesses the impact of the potential failure of the new UK energy policy to achieve the new gas and nuclear power deployment ambitions within the timeline at which aging coal and nuclear power plants are expected to close. At the backdrop of this severely constrained nuclear power and gas capacity penetration in the mix by 2030, the electricity generation mix likely to be assembled to resolve the electricity supply crisis could have far reaching implications on the key decarbonisation targets. The potential growth in the UK population, and the surge in the electrification of heating and transportation by 2030, is set to increase the demand for electricity. It appears that the new energy policy strategy is highly optimistic if not unrealistic to expect about 26-30 GW capacity of a fleet of new gas plants to be built within a ten year period which happens to coincide with the anticipated plant closures (DECC, 2012e; Institution of Mechanical Engineers, 2016). In the midst of the current uneconomic market environment for gas generation sector, the future of the UK existing 28.9 GW gas installed capacity by 2030 remains uncertain despite the indications that only 10 GW de-rated capacity could be closed by 2030 (CCC, 2015).

The scenario assessment developed in this section suggests that the ‘dash’ for new gas-fired generation proposed by the new UK energy policy may not materialise by the time most of the aging coal and nuclear power plants are expected to close. The UK government has already run out of time to bring forth the ambitious new gas, nuclear power and offshore wind by 2030. A study by Gross (2015) on approaches to cost reduction in CCS and offshore wind pointed out that it takes about five years for a new wind farm or gas-fired power station to go through consenting and construction, and closer to a decade for new nuclear power stations or large offshore wind farms. The time needed to develop and deploy the technologies to meet the security of supply objectives of the new UK energy policy could prove to be a major stumbling block against this policy initiative. The deployment of gas-fired capacity to the tune of 26-30 GW by 2030 may be impossible in the context of the assessment made by the Institution of Mechanical Engineers (2016) which suggests that in the past 10 years, the UK has built just four CCGT plants. The significance of timelines in the development of energy supply infrastructure cannot be understated. Therefore, at the backdrop of this assessment, it is almost certain that no more than one new nuclear plant will be commissioned by 2030, and that the large scale deployment of gas-fired generation may not happen in the period projected by the new UK energy policy. The analysis undertaken in this section adopts an alternative approach to the ambitious new energy policy to address the security of electricity supply concerns, but with severe implications on the UK decarbonisation targets.

With the coal generation sector expected to close by 2025 (DECC, 2015a), the UK government is anticipating that the capacity market mechanisms could drive investment in new gas generation infrastructure to replace the capacity shortfall created during the 2020s plant closures. However, the second capacity market auction held in December 2015 failed to attract any investment in new gas-fired plant development required for the scope of the new energy policy. While commenting on the outcome of the December 2015 capacity market auction, the environmental think-tank Sandbag (2015), noted that over 5 GW capacity of existing coal plants were awarded contracts, despite the UK government’s plans to phase out all coal generation by 2025. The first capacity market auction conducted in 2014 resulted in about 9.2 GW of existing coal securing capacity contracts to operate during the 2018-19 winter period (Littlecott, 2015). The apparent inconsistencies within the capacity market mechanisms has simultaneously granted coal plant operators the means not only to comply with the EU emissions limits, but also to consider the prospects for plant life extensions for the existing coal fleet. At the backdrop of this financial enabling climate for the existing coal plants, it is reported that seven stations have elected to sign-up to the EU's IED limits rather than apply to opt-out (Stacey, 2016). This is a demonstration of confidence by the coal utility operators that the level of uncertainty inherent in the UK short and medium-term energy policy could bring financial dividends to a sectors which could potentially be destined for extinction within the UK electricity supply landscape.

An investment outlay to the tune of £293 and £80 million was awarded to the existing fleet of coal plants during the 2014 and 2015 capacity market auctions (Sandbag, 2014, 2015). The revenue generated through the capacity market auctions could contribute significantly towards the generation of the capital investment required to purchase and retrofit the abatement technology necessary to comply with the IED regulations as well as to undertake plant life extensions work. The IED requires industrial plants, including the existing UK coal plants to limit the emissions of sulphur dioxide (SO_2), nitrogen oxides (NO_x) and particulate emissions (pm10) based on the total rated thermal output of the plant and the type of fuel used as outlined in Table 4.3. The existing UK coal-fired stations have a generation capacity of over 300 MW with NO_x levels currently pegged at around 500 mg/Nm^3.

Table 4.3. The emission limit values (mg/Nm^3) for coal-fired plants as set out in Annex v of the IED (European Council, 2010).

Total rated thermal output (MW)	Sulphur dioxide (SO_2)	Nitrogen (NO_x)	Dust (pm10)
50 - 100	400	300	30
100 - 300	250	200	25
>300	200	200	20

Compliance with the IED emission values shown in Table 4.3 would require secondary post combustion abatement techniques in the form of selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) or hybrid (SNCR and SCR). These abatement approaches are arguably the only methods by which coal plants can reduce the emission limit values (ELV) from 500 to 200 mg/Nm^3 (Parsons Brinckerhoff, 2014). The SCR and SNCR abatement technologies have a NOx removal rate of about 40 % and 80 %, respectively relative to the 56 % required to achieve the IED's stipulated ELV of 200 mg/Nm^3 illustrated in Table 4.3 (Parsons Brinckerhoff, 2014; European Council, 2010). Therefore, since SCR alone is incapable of achieving the IED mandatory ELV post 2016, this implies that an integrated hybrid SCR/SNCR retrofit configurations would have to be considered for the existing UK coal fleet in order to achieve ELV beyond the mandatory limits highlighted in Table 4.3.

The coal utility operators that choose to comply with the IED would have to consider investing in the abatement technology with a scope to achieve ELV of about 200 mg/Nm^3 as from January 2016 (Parsons Brinckerhoff, 2014). The cost estimate in Table 4.4 reflects both the abatement technology and life extension cost for the coal plants that could allow the existing fleet of coal plants to continue supplying energy needs for the UK economy. It is envisaged that these plant upgrades could be partly financed using the funds generated from the operational contracts acquired through the capacity market mechanisms. Since the cost estimate shown in Table 4.4 is by no means prohibitive to further investment in existing coal fleet, the prospects for the continual operation of coal plants beyond the UK government's 2025 closure timeline could compromise on the development of new gas generation infrastructure which is at the centre of the new UK energy policy.

Table 4.4. The estimated cost of complying with the IED regulations and a ten year life extension of the existing UK coal power plants (Parsons Brinckerhoff, 2014).

Existing coal plant upgrades	Medium Capex (£/kW)	Medium Opex (£MW/y)
Coal(Pulverised Fuel, ASC with FGD) Non-IED	1954	60602
Coal (Pulverised fuel, ASC with FGD) with IED/SCR + Extension	2101	65013
Coal (Pulverised fuel, ASC with FGD) with IED/Hybrid SCR/SNCR + Extension	2069	69119

In the absence of explicit policies obliging coal generation to close, the 'High CPS', 'Pro-coal' and No CPS', scenarios developed to explore the potential future for coal generation by 2030 have respectively showed that a 5,9 and 11 GW unabated coal generation capacity could be retained in the generation mix by 2030, (Gross et al., 2014). While the introduction of the carbon price support (CPS) could have made coal generation proportionally more expensive, the capping of the price escalator at 2015 levels to 2019 has further thrown a lifeline to the future of coal generation at the expense of investment in new gas plants. The complete removal of the CPS could potential improve the attractiveness of gas generation, and thus assisting in luring the investment required to support the rollout of a new fleet of gas plants by 2025. The potential option to remove the CSP from the list of the EMR decarbonisation instruments to promote increased investment in new gas plants could further enhance and prolong the continuation of unabated coal generation in the mix unless coal closures are mandated by legislation. While the future of the CPS remains uncertain beyond 2020, the potential of this policy instrument being removed or further reduced from the £18/tCO_2 capped level (HM Treasury, 2014) is highly unlikely as it risk bringing the UK government's commitment to developing a low-carbon electricity sector under intense scrutiny.

The electricity generation installed capacity portrayed in Figure 4.3 is representative of the electricity sector outlook in 2030, where the policy ambitions for new gas and new nuclear power plant deployment fails to achieve the milestone anticipated by the new UK government energy policy. It represents an electricity sector transition reflecting a catalogue of failures and miscalculations in framing the new direction of the new energy policy. The scenario narrative advanced by Figure 4.3 assumes that the UK government's policy will fail to restrict funding on emission intensive coal and reciprocating diesel engines at the expense of low-carbon technologies such as gas, interconnectors and nuclear energy. As a result of these policy incoherencies, unabated gas installed capacity is mainly dominated by old gas plants with few new plants added to the mix. The technology deployment outlay demonstrated in Figure 4.3 is a departure from the new energy policy ambition which sought to see gas, nuclear and offshore wind energy as the key drivers in mitigating the security of supply challenge.

Despite the stall in the development of new gas plants, progress in the development and deployment of offshore wind is evidently clear in Figure 4.3 where 22.2 GW is achieved by 2030. With about 5 GW offshore wind installed capacity currently in the UK generation supply system (RenewableUK, 2016), the industry has managed to build a total of about 17.2 GW capacity between now and 2030 as illustrated in Figure 4.3. This implies that the offshore wind technology did manage to achieve cost-competitiveness at renewable CfD auctions, a stipulation which was emphasised during the unveiling of this new UK energy policy. The deployment outlay for offshore wind portrayed in Figure 4.3 meets the UK government policy indicative estimates suggesting a total installed capacity of 10 GW by 2020 followed by another 10 GW deployment through the 2020s as the costs fall below the £100/MWh threshold (DECC, 2015a; The Crown Estate, 2012).

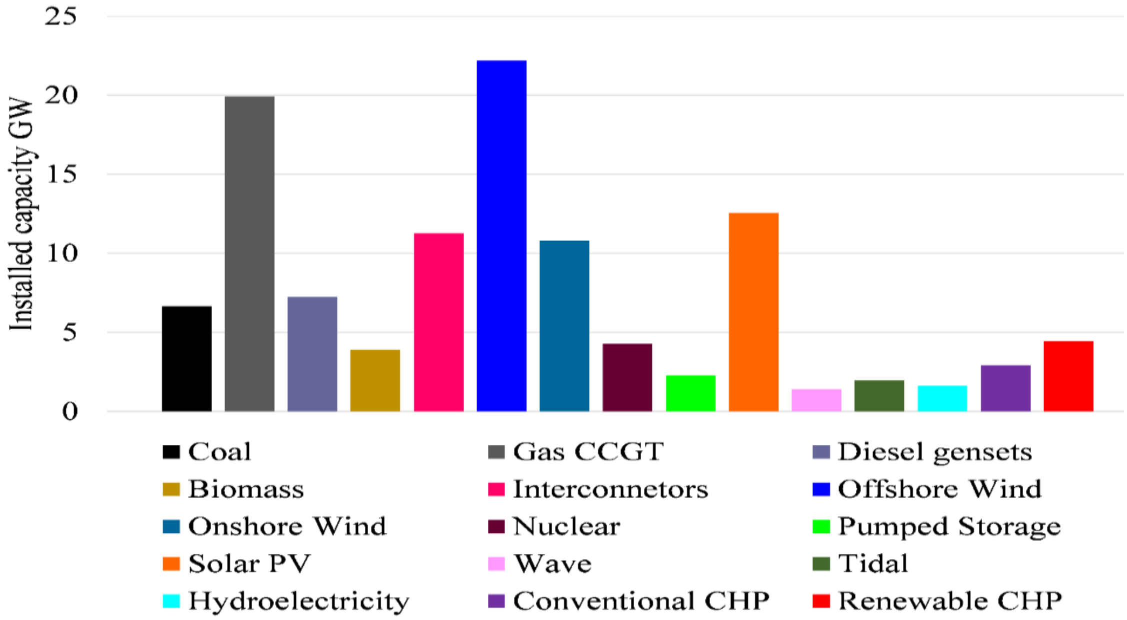

Figure 4.3. The UK electricity generation mix outlook in 2030 for the alternative scenario to the new UK energy policy ambition.

The withdrawal of financial support for onshore wind and solar PV during this transition period is assumed to have led to a 10.8 and 12.5 GW installed capacity by 2030, respectively. Given the delay in the development of new nuclear power generation plants, the contribution from onshore wind and solar PV is significantly vital to the collective goal of alleviating the potential security of supply challenges following unprecedented plant closures through the 2020s. In the context of onshore wind, the deployment trajectory by 2030 shown in Figure 4.3 implies that a capacity build of 2.3 GW was achieved relative to the current 8.5 GW installed capacity (RenewableUK, 2016a). The constrained growth in the onshore wind sector could be attributed to the withdrawal of green subsidies which is assumed to have had the effect of polarising investor attitudes towards investing in onshore wind projects. In the same vein, an 8.3 GW deployment capacity for solar PV recorded by the end of December 2015 (DECC, 2016) indicates a 4.3 GW growth in the period to 2030 as shown in Figure 4.3. Based on the latest figures and trends from DECC, the financial support mechanisms for solar PV from the beginning of 2014 to the end of 2015 resulted in staggering 152 % increase in the deployment of solar PV, that is from 3.3 GW to 8.3 GW (DECC, 2016). The UK government's rationale for withdrawing solar PV subsidies was based on the understanding that the industry had achieved a competitive edge for it not to require any financial support from government in order to compete with other renewable technologies. However, based on the deployment estimate for solar PV shown in Figure 4.3, the withdrawal of financial aid for solar PV projects appears to have had undesired effects as only 4 GW is estimated to have been achieved in 14 years compared to 5 GW capacity growth in one year with subsidies in place.

As the existing nuclear power plants decommission through the 2020s, the installed capacity shown in Figure 4.3 indicates the likely contribution from nuclear energy which is expected to comprise of 3.2 GW from Hinkley Point C new nuclear generation plant and 1.2 GW, a remnant generation capacity from the old nuclear fleet. The new CCGT renaissance referenced in the new UK energy policy and the UK nuclear industry's estimated 16 GW new build programme by 2030 (DECC, 2015a; HM Government, 2013b) is not likely to be achieved, as demonstrated in Figure 4.3. Assuming that new nuclear and gas plant capacity is not delivered as expected by 2030, the capacity deficit created could be resolved through the continual operation of the existing life-extended coal plants combined with the contribution from reciprocating diesel generators and interconnectors. The resurgence in the use of existing old coal plants could see about 6.7 GW capacity operating by 2030, as highlighted in Figure 4.3. The availability of coal generation by 2030 in this scenario is assumed to have been necessitated by the failure of the new UK energy policy to deliver new nuclear and gas generation capacities to close the widening gap between supply and demand resulting from plant closures in the period to 2030.

A glimmer of hope for the coal plant operators on the potential future use of a proportion of the existing coal capacity beyond 2025 was glaringly evident from the statement expressed in the new UK energy policy. In unveiling the new energy policy, the UK government indicated that it would proceed with the proposed 2025 closure timeline for coal plants if it is confident that the shift to new gas can be achieved within the proposed timescale (DECC, 2015a). The viability of coal generation capacity shown in Figure 4.3

is likely to have been facilitated by the assumed extension of the CPS cap of £18/tCO_2 applied during the 2015 to 2020 period (HM Treasury, 2014) to 2030. This policy shift is assumed to have originally been intended to encourage investment in the development of new gas infrastructure to ameliorate the energy security crunch created by increased plant closures through the 2020s. Assuming that the £18/tCO_2 CPS level is retained through to 2030 and the eligibility of coal plants to participate in capacity market auctions is maintained, this could still make the operation of existing coal plants economic during this period, and hence the deployment outlay portrayed in Figure 4.3.

In the event that the deployment capacity for new nuclear and gas power plants is not delivered as expected by 2030, there is significant technology diversity within the generation mix to compensate for the capacity gap created (see Figure 4.3). Based on the technology mix portrayed in Figure 4.3, the lack of progress in the new nuclear and gas plant developments would not pose an immediate threat to security of supply. However, a mixed energy portfolio with a total installed capacity of 116 GW, with 32 % of that capacity comprising of unabated fossil generation could have huge implications on the UK carbon targets. The emission performance of the fossil fuel-fired technologies in Figure 4.3 is displayed in Table 4.5 and has huge implications on the electricity supply sector decarbonisation ambitions.

Table 4.5. The emission performance of an alternative energy pathway to the new UK energy policy by 2030.

Unabated fossil generation	Installed capacity GW	Load Factor %	Emission gCO_2/kWh	Emissions MtCO2e
Coal	6.7	0.37	990	16.2
CCGT	19.9	0.5	488	42.1
Diesel generators	7.2	0.13	1010	8.2
Conventional CHP	2.9	0.33	488	3.7

The shift in the new UK energy policy to a gas renaissance without the benefit of CCS signals a difficult future for the UK low-carbon economy. The potential failure of the new energy policy to bring forth the new gas and nuclear power plants and the advent adoption of the generation portfolio outlay indicated in Figure 4.3 by 2030 would make it difficult to comply with the emission budgetary requirements proposed by the fifth carbon budget for the power sector. The emission output from the unabated fossil fuel sources shown in Table 4.5, account for 70.2 $MtCO_2e$ by 2030, which is 126 % of the fifth carbon budget Central Scenario emission target of 31 $MtCO_2e$ of total emissions to be achieved by the power sector by 2030 (CCC, 2015). The emission output from CCGT operation alone is 11.1 $MtCO_2e$ more than the entire budgetary requirement for the power sector.

The operation of coal and reciprocating diesel engines at 37 % and 13 % capacity factors (see Table 4.5) produce a combined electricity output of 27 TWh, as illustrated in Figure 4.4, but yet the total emission from these two technologies is over 50 % of the fifth carbon budget target for the power sector by 2030. The high carbon intensity of coal and diesel generators shown in Table 4.5 leads to an increase in the amount of carbon emissions from this scenario even though the electricity generation contribution towards the total demand is significantly low within the generation mix. In adopting a scenario with coal and diesel generators (see Figure 4.3) in the mix, it appears as if the UK government has limited options to present any sustainable generation mix to meet demand following the failure to achieve new gas and nuclear power deployment ambitions by 2030. This implies that the policymakers would have to face the long-term costs of meeting carbon targets and provision of affordable energy to consumers.

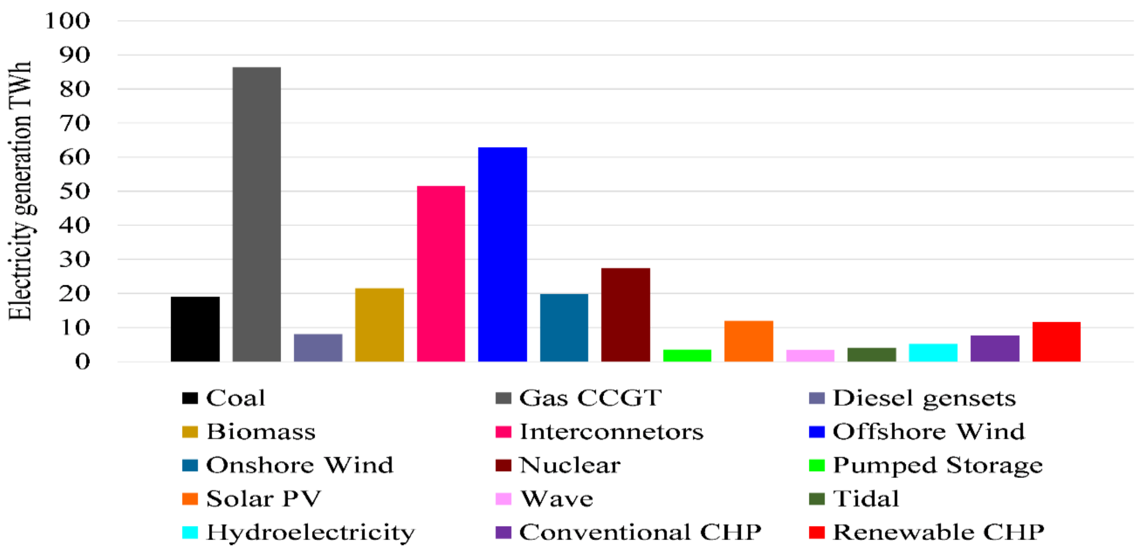

Figure 4.4. The UK electricity generation output in 2030 for the alternative scenario to the new UK energy policy ambition.

The proliferation of diesel generators is set to increase in the period to 2030 due to the limited policy mechanisms currently in place to constrain their operation. The diesel generation units in the UK generation mix are operated outside the capacity criteria for regulating conventional electricity generating plants in the UK. The limited operational capacity and the annual average run times ensure that diesel generators fall below the EU ETS which is subject to installations with a total rated thermal input exceeding 20 MW (Environment Agency, 2013). In the context of the IED which seeks to limit air pollutants other than carbon emissions, diesel generators are not affected by this directive as they are operated far below the 500 hours derogation annual operational threshold which covers solid, liquid and gas-fired plants (Environment Agency et al., 2013). Also the regulatory immunity of diesel gensets extends to the EPS which limits the emission output of installations of over 50 MW to 450 gCO_2/kWh (DECC, 2012c).

With the exception of the CPS, the existing favourable regulatory and the financial arrangements through the capacity markets implies that diesel generators could contribute in mitigating security of electricity supply challenges despite being a greater source of carbon emissions. Despite the high penetration of diesel generator capacity in the system (see Figure 4.3) the electricity generation output of 8 TWh, shown in Figure 4.4, is consistent with their expected role of ‘peaking plant’. It is highly likely that the capacity factor for diesel generators indicated in Table 4.3 is indicative of a very serious capacity deficit in 2030 which could allow the generation units to run well beyond the normal peaking periods. With little regulatory constraints in place to restrict the operation of diesel generators, their role in the generation mix could be vital, especially where flexible technologies such as nuclear power and new gas CCGT plants encounter huddles in their deployment by 2030.

The electricity generation from interconnectors reach 52 TWh from the 11.2 GW installed capacity in 2030 as shown in Figures 4.3 and 4.4, respectively. The potential interconnector capacity portrayed in Figure 4.3 is based on the assumption that the project pipeline outlay projected in Table 4.2 is achieved by 2030. Assessments made by the environmental think-tank, Sandbag (2015), on the last capacity market auction in December 2015 show that only 1.862 GW of de-rated capacity of old interconnector was awarded a 1 year contract to supply electricity. No new interconnector projects (see Table 4.2) were awarded any contracts during this auction as the prices were not high enough to attract any bids from developers. However, the interconnector capacity portrayed in Figure 4.3 implies that the future capacity market auction prices would need to improve significantly if the 15 % of total electricity generation shown in Figure 4.4 is to be realised. The development and improvement of a market for the interconnector electricity networks should be prioritised by the UK government, especially if the role of coal in the generation mix is to be significantly reduced. The interconnection capacity indicated in Figure 4.3 is in line with the view that greater levels of interconnection are generally associated with better security of supply. Hence, the electricity generation output from interconnectors demonstrated in Figure 4.4 would imply that all the new projects earmarked for development in the next 15 years (Table 4.2) would need to be supported in order to reduce security of supply risks as flexible gas and nuclear power fail to achieve deployment targets by 2030.

The failure of the new UK energy policy to deploy significant new gas and nuclear power capacity by 2030 suggests a grim future on the decarbonisation stance that the United Kingdom harbours. Although the new nuclear power capacity is likely to increase after 2030, the capacity of the sector to steer the UK economy on track to the 2050 emission reduction target by 2050 could be challenging. This is mainly because of the high deployment prospects of unabated gas following the eventual total phase out coal from the system after 2030. The prospects for a CCS era after 2030 depends on the government's capacity and willingness to unveil comprehensive new CCS investment policies that could convince utility operators and other potential investors of their total commitment to decarbonisation. Following the UK government's unceremonious abandonment of the CCS commercialisation programme, the indications are that the UK government is likely to find it extremely difficult to regain confidence and support from the industry and the investor community on future CCS related clean energy projects.

The decarbonisation analogue projected by the two new energy policy pathways (Figures 4.1 and 4.3) does not reflect any commitment to developing a clean electricity sector, a view which the UK government still harbours. However, a comparison of the emission performance of the new energy policy scenarios against the 2030 decarbonisation pathways in Figure 4.5 suggests a worrying future of the high probability of the electricity generation sector and potentially the entire UK economy missing both the 2050 emission reduction target and other international decarbonisation commitments. Based on Figure 4.5, the total emissions from the two scenarios linked to the new UK energy policy account for over 80 MtCO_2e compared to 34 MtCO_2e for the 'path to 100 g' scenario which is highly recommended to keep the UK economy on track to the 2050 emission reduction target. The total emission from the UK electricity generation sector was about 203.5 $MtCO_2e$ in 1990 (DECC, 2014a). In the context of the 100 gCO_2/kWh grid intensity for the electricity generation sector by 2030 which is being advocated by the fifth carbon budget (CCC, 2015) implies that the sector would have to reduce its emissions by 85 % of the 1990 level.

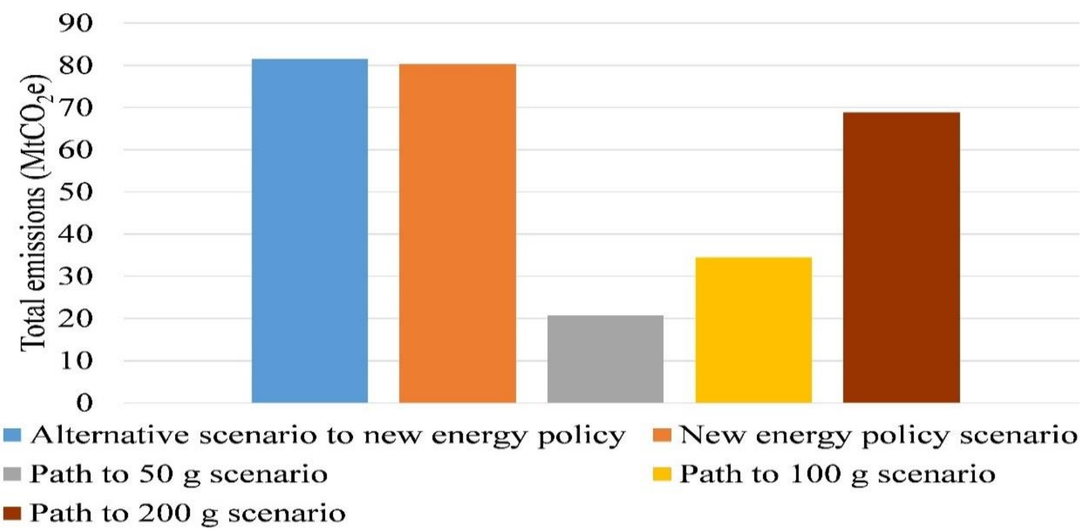

Figure 4.5. A comparison of the emissions from the new energy policy scenarios against the decarbonisation pathways by 2030.

The total emission output from the two new energy policy related scenarios portrayed in Figure 4.5 indicate that the electricity generation sector can only achieve an average of 40% emission reduction against the 1990 level by 2030. The radical shift in the policy direction from a clean energy strategy seeking to achieve a 50 to 100 gCO_2/kWh grid intensity to one which achieves about 236 g/kWh grid carbon intensity by 2030 is extraordinarily detrimental to the UK's low-carbon energy future prospects. It is clear that the new UK energy policy focus on unabated gas as a driver of the UK electricity generation is at odds with the vision of developing a low-carbon economy. A 'dash' for new gas as proposed by the new policy framework could make it absolutely impossible to meet national emission targets affordably as this decarbonisation ambition by 2030 is dependent on the rollout of a diversified generation mix of nuclear, CCS and renewables with gas generation reserved for system balancing (Clarke, 2016).

The fossil fuel dependency in the electricity sector is dominant in the 'path to 200 g' and the two new energy policy related scenarios as demonstrated by the high levels of emissions in Figure 4.5. The total emission outlay in Figure 4.5 is a result of the extent to which unabated fossil fuel generation technologies shown in Figure 4.6 are employed to address electricity demand challenges against the aspirations for the low-carbon future energy systems. The level of CCGT emissions for the new energy policy scenario shown in Figure 4.6 is a result of the failure of new nuclear power plants to achieve the deployment capacity levels expected. However, assuming that 8.7 GW of new nuclear capacity was to be deployment by 2030, the gas renaissance pursued by the new UK energy policy would still achieve 66 $MtCO_2e$ with interconnector capacity reduced to 8 GW. As the new UK energy policy stands, it is inconceivable that the emission performance of CCGT in Figure 4.6 could be aligned with the goal of achieving a new zero carbon emission electricity supply sector by 2050.

An alternative scenario to the new energy policy has similar decarbonisation shortcomings despite the constrained penetration of CCGT by 2030. While the level of emissions in the alternative scenario is 22 $MtCO_2e$ less than in the new UK energy policy scenario, the difference is neutralised by the emission contribution from coal and diesel generators. As a result, the increased use of unabated fossil-fired generation plants in the alternative scenario to the new UK energy policy, and ‘path to 200 g’ scenario shown in Figure 4.6 is not compatible with the objective of developing a cost effective path to the 2050 emission reduction target.

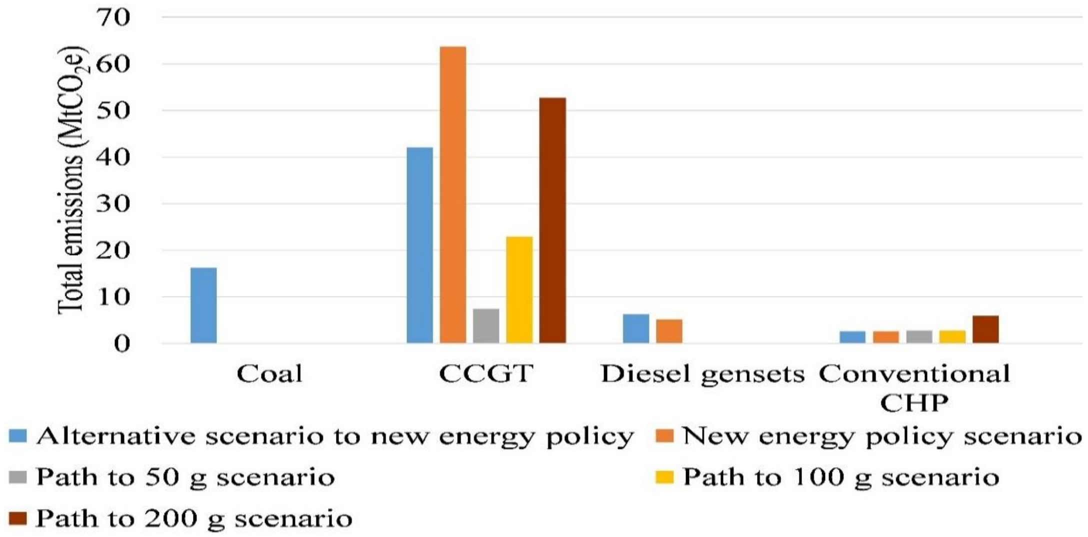

Figure 4.6. Comparison of the emission output from unabated fossil fuel generation across different scenarios by 2030.

4.2.3 The new UK energy policy: the feasibility of a near zero emission power sector by 2050

The evolution of the UK electricity generation sector under the new UK energy policy framework (DECC, 2015a) is set to miss the decarbonisation target of below 100 gCO_2/kWh by a very wide margin as shown in Figure 4.5. The focus of this section is to examine the changes that the UK government would have to adopt in its energy policy framework in order to realign it with the vision of developing an almost carbon neutral electricity sector by 2050. While the 2030 decarbonisation target is now beyond reach in the context of the protracted delays in new nuclear power deployment, abandonment of the CCS commercialisation programme and the cancellation of renewable energy subsidies, there is a need to reframe the current UK energy policy to urgently develop a new approach to CCS in order to maintain the momentum to meeting the long-term goal of reaching net zero emissions by 2050 (CCC, 2016). While CCS has been hailed as one of the key drivers in achieving cost-effective decarbonisation to 2050, analysis by the ETI estimate that a ten year delay in developing the CCS capability could add £4-5 billion per year to the cost of decarbonising the UK economy (Clarke, 2016). In reframing the new UK energy policy, a new approach to the development and rollout of the CCS infrastructure and capture projects in power, gasification and industry in the 2030s and the 2040s would have to be fast tracked in order to avoid substantially higher costs of meeting carbon targets beyond 2030 (CCC, 2016; Clarke, 2016).

Progress in the development and deployment of new nuclear energy plants is set to intensify through the 2030s. While the total deployment outlay to 2050 remains uncertain, the proportion of nuclear power projects outlined in Table 4.6 could provide an indication of the potential capacity estimate likely to be rolled out through the 2030s to bolster both security of electricity supply and decarbonisation objectives. The urgency to use new nuclear power to decarbonise the electricity sector and to enhance security and diversity of energy supply is clearly elaborated in the national policy statement (NPS) where the UK government identified eight suitable sites (see Table 4.6) for the significant development of new nuclear power plants earlier than the end of 2025 (DECC, 2011b). The ambition to achieve a significant deployment capacity for new nuclear power before 2025 was driven by the need to avoid the risk of the UK electricity supply sector being locked into a higher carbon energy mix as well as the associated difficulty and expense of meeting the decarbonisation carbon budgets (DECC, 2011b). Even though the target to develop more new nuclear power stations before the end of 2025 and 2030 has slipped, the mandate to work towards the 2050 emission target remains a legal obligation for the UK government to achieve.

However, once the current financial hurdles affecting the first new nuclear power plant development (Hinkley Point C) are overcome, the prospects of an accelerated development and deployment of new nuclear power generation infrastructure on the sites already identified could be instrumental in tackling the emission legacy caused by the delay in achieving the low-carbon deployment targets by 2030. The prospects of higher electricity demand driven partly by population growth and the electrification of transport and heat from 2030 to 2050 could provide the impetus for the growth in the nuclear electricity sector. While the projected new nuclear power development considered in this thesis has been limited to the sites and capacity shown in Table 4.6, scenarios that informed the UK Government's Carbon Plan in 2011 and the Fourth Carbon Budget indicated that a range of 23 to 55 GW of new nuclear power capacity could be required by 2050 under different cost and policy assumptions (Carbon Connect, 2014). A clear and stable policy framework is urgently required to promote a balanced approach in the deployment of nuclear, CCS and renewable energy technologies. This policy framework could facilitate a rapid reduction in emissions from 2030 through to 2050 to achieve an almost carbon neutral sector commensurate with the 80 % emission reduction target relative to the 1990 levels.

Table 4.6. Planned and proposed UK new nuclear power development (World Nuclear Association, 2015b).

Proponent	Site	Reactor model	Megawatts
EDF Energy	Hinkley Point C-1	EPR	1680
	Hinkley Point C-2	EPR	1670
	Sizewell C-1	EPR	1670
	Sizewell C-2	EPR	1670
Horizon	Wylfa Newdd 1	ABWR	1380
	Wylfa Newdd 2	ABWR	1380
	Oldbury B-1	ABWR	1380
	Oldbury B-2	ABWR	1380
NuGeneration	Moorside 1	AP1000	1135
	Moorside 2	AP1000	1135
	Moorside 3	AP1000	1135
China Generation Nuclear	Bradwell B-1	Hualong One	1150
	Bradwell B-2	Hualong One	1150

An enabling financial, planning and regulatory environment could successfully promote the delivery of 17.9 GW capacity of new nuclear power plants as shown in Table 4.6. This deployment outlay of new nuclear power infrastructure through the 2030s and early 2040s is now dependant on the investors' capacity to unlock the required investment on time for the nuclear projects to start. As the urgency to decarbonise the UK economy and the electricity supply sector deepens, the deployment trajectory for conventional large nuclear reactors portrayed in in Table 4.6 may not be sufficient to drive down emissions to near zero level by 2050. As a result, a renewed focus on new infrastructure development could extend to include new emerging technologies such as the small modular nuclear reactors (SMR). By virtue of being low-carbon technologies, these unconventional nuclear power plants could be harnessed to provide baseload electricity supply as well as contribute in narrowing the emission gap when used in combination with other low-carbon technologies.

In contrast to the conventional large nuclear power reactors, SMR have designs with a maximum capacity of 300 MW, and thus allowing for the components to be assembled in offsite factories and for the deployment of multiple reactors at the same site to form larger power plants (ETI, 2015). By virtue of their smaller physical size in comparison to conventional large nuclear reactors, SMR are believed to be quicker to build, a feature which could make them an attractive alternative solution to mitigate the UK potential supply deficiencies in the midst of plant closures through the 2020s. These characteristic hold the key for the prospective rapid development and rollout of this technology to mitigate the key electricity supply challenges facing the UK. However, the potential for SMR to achieve commercial readiness and rapidly move to full swing deployment is dependent on investor attitudes, the pace of the supply chain developments as well as on the extent to which the UK energy policy view the technology as an integral part of the UK's nuclear energy and low-carbon agenda.

The case for integrating SMR in the UK electricity sector is growing stronger, particularly at a time when key decarbonising technologies are either facing investment or political uncertainty. Analysis by the ETI suggests that the first commercial deployment of SMR power plants could be operating in the UK in the early 2030s, assuming that substantial challenges relating to supply chain development, investment and public acceptance are carefully addressed (ETI, 2015). The National Nuclear Laboratory (2014) feasibility study on SMR concluded that there is an opportunity for SMR to be integral to the UK's nuclear energy and low-carbon agenda. One of the key benefits of the SMR technology is its ability to provide reliable baseload electricity, cogeneration of heat and electricity as well as energy storage capacity (ETI, 2015). It is envisaged that once the supply chain development hurdles are resolved and the SMR capability achieves commercial readiness, an annual build rate of 0.2 and 0.4 GW capacity could be achieved from 2032 based on the 'low' and 'mid' deployment scenarios, respectively (ETI, 2015).

The development of nuclear technology through this transition period could result in 36.8 GW installed capacity by 2050 comprising of conventional nuclear and SMR plants as shown in Figure 4.7. The deployment outlay for the nuclear technologies shown in Figure 4.7 is likely to be driven by the fall in the deployment cost for the technologies which by 2050 would have reached maturity. By this period the levelised cost of electricity for SMR plants could reach £91/MWh based on the results from the EOC. This electricity cost indicator for the SMRs is competitive to the £92.50/MWh awarded to the Hinkley Point C plant (DECC, 2014i) although the cost projections for these unconventional nuclear plants are still subject to change. The accelerated and sustained deployment of both conventional and SMR nuclear technology post 2030 is consistent with the ambition to decarbonise the electricity generation sector to a near zero carbon status by 2050. Again, the extent to which this ground-breaking technology can be fast tracked into the UK electricity generation mainstream is dependent on a consistent policy framework with a capacity to convince investors to invest in the development of the technology. Also, the UK government would need to maintain its appetite for the SMR technology by channelling financial resources towards further research and development for the SMR in order to bring down capital costs.

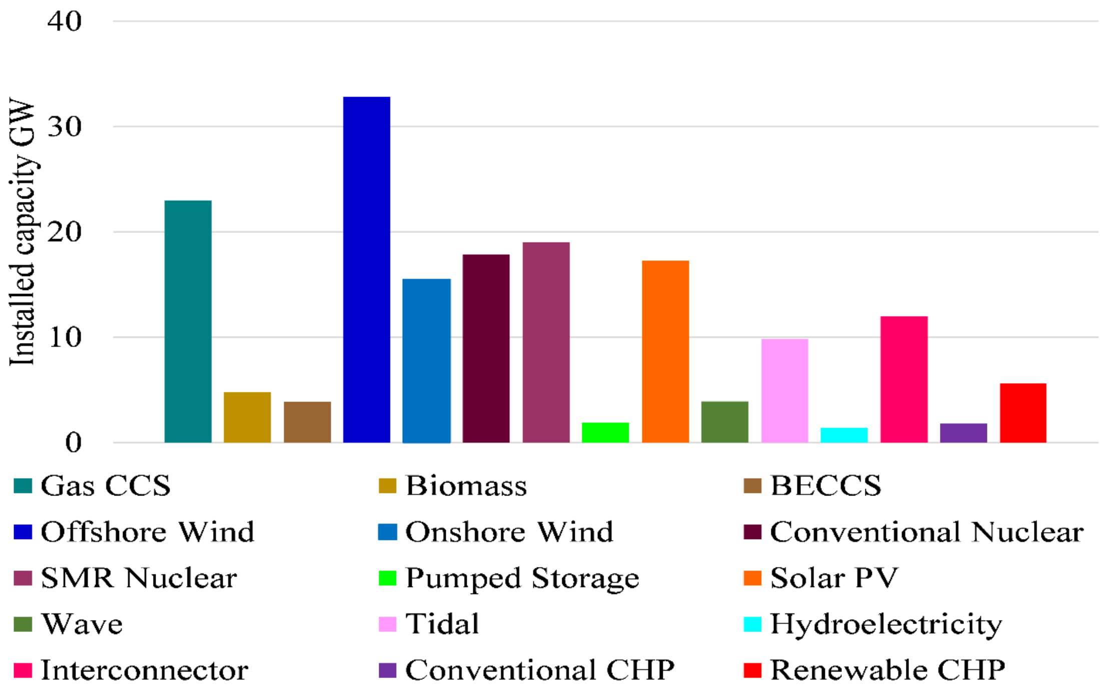

Figure 4.7. The 2050 UK electricity generation mix developed following the reframing of the new UK energy policy leading to the accelerated low-carbon energy technology development after 2030.

A surge in the deployment of offshore wind to achieve 32.8 GW by 2050 (see Figure 4.7) is a result of the technology having become competitive among the renewable energy sources. A reinvigorated UK energy policy racing to align economy-wide emissions to the legislated carbon budgets could promote the rapid growth of the offshore wind industry to achieve the £78/MWh LCOE by 2050 as the deployment outlay surpasses the 30 GW mark as shown in Figure 4.7. The progress in the deployment of onshore wind and solar PV shown in Figure 4.7 demonstrates a policy framework that accommodates and supports a diversity of technologies to accelerate emission reduction in the power sector and the economy as a whole. An increase in the deployment capacity of onshore wind in this renewed campaign to decarbonise the electricity sector (see Figure 4.7) compared to new UK energy policy (see Figure 4.1) could be a result of increased public acceptance in pro-onshore wind communities which could promote the development of wind. New legislative changes to be brought in by the Energy Bill 2015/16 targeting onshore wind could see the transfer of the existing consenting powers on large onshore wind projects of over 50 MW from the Secretary of State to the local planning authority (HM Government, 2015). As the final decision on the future development of onshore wind in England and Wales is distanced from the political influences and powers of Whitehall, this could increase the support and deployment of onshore wind, especially in communities that promote all forms of renewable technologies in the UK electricity generation system.

The CCS capture readiness of the CCGT plants rollout by the new UK energy policy 'reset' has the strategic advantage of facilitating the rapid deployment of CCGT fitted with CCS up to 2050 as depicted in Figure 4.7. A total of 23 GW capacity of CCGT plants are retrofitted with CCS infrastructure which by this time would have developed to significant economic scale to realise the economic as well as radical decarbonisation benefits. The development of the full CCS infrastructure cycle in its entirety by adopting the whole system approach (capture, transport and storage) could support the deployment capability demonstrated in Figure 4.7. The integration of CCS in biomass-fired plants to about 4 GW capacity could induce negative emissions in the whole abatement process, and thus further deepening the cuts in emissions to achieve a grid carbon emission target of 5 g/kWh based on the low-carbon technology portfolio depicted in Figure 4.7.

The absence of unabated CCGT in the generation mix in 2050 (see Figure 4.7) could be a result of uneconomic operation environment, especially where much of the fossil fuel capacity could be operated below 10 % capacity factor threshold which could be unlikely to earn sufficient return in an electricity-only market to justify investment (CCC, 2014). The proliferation of interconnector networks by 2050 could result in 12 GW installed capacity (see Figure 4.7) which could be combined with the output from CCS generation plants to mitigate issues of intermittence and any demand uncertainty. Increased investment in CCS technology following the reframing of the new UK energy policy means that 23 GW of the new gas capacity promoted by the policy is successfully retrofitted with CCS capability to bolster energy security needs as well as deep cuts in emissions.

With the UK demand for electricity set to increase by 30 to 100 % by 2050 (DECC, 2012d), the electricity generation outlay presented in Figure 4.8 has the capacity and diversity to address any demand uncertainties that could arise as the system decarbonises. Based on an estimated 620 TWh electricity demand by 2050 following significant developments in the electrification of transport and heating, the bulk of this demand is likely to be supplied by gas CCS, nuclear generation systems, offshore wind and interconnectors. Conventional nuclear and SMR have a combined generation output of 36 % of total demand while CCGT fitted with CCS and offshore wind contribute 23 and 14 % of the total electricity generation by 2050, as shown by the electricity generation proportions in Figure 4.8, respectively.

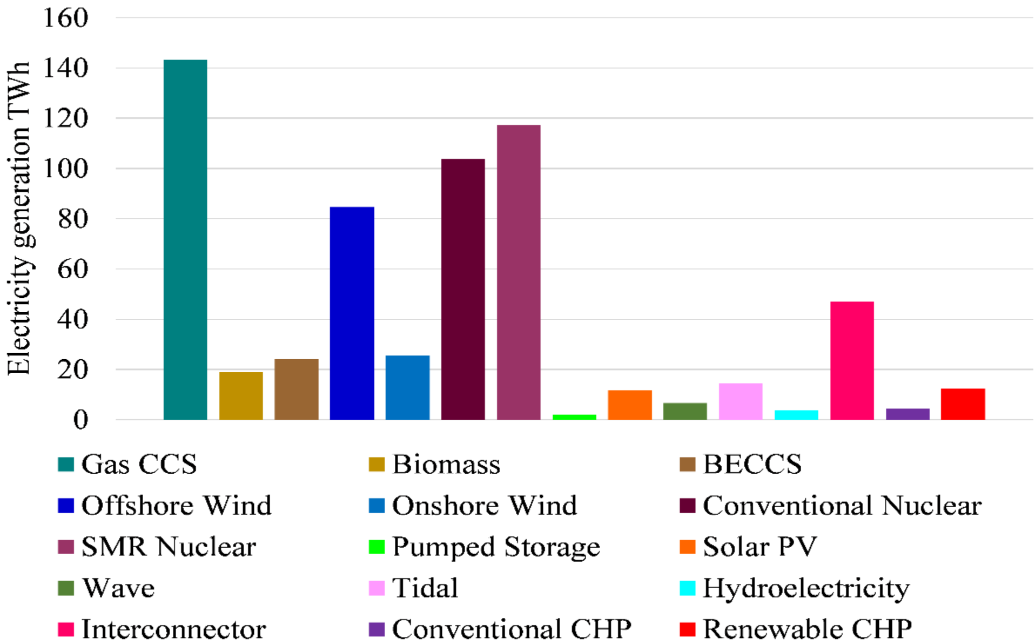

Figure 4.8. The 2050 UK electricity generation from the accelerated deployment of low-carbon energy technologies from the 2030s to 2050.

The UK electricity generation portfolio in Figure 4.8 is solidly buttressed by a potential 75 GW baseload capacity depicted in Figure 4.7 which could go a long way in meeting the power supply needs for economic development. The interconnector networks across the Europe that are integrated into the UK electricity supply network (see Table 4.2) could potentially supply 8 % of the total electricity generation. The interconnector capacity in the mix could bring the much required flexibility to address the intermittent supply challenges likely to be induced by 86 GW capacity from renewable energy sources in the generation mix such as wind, solar and marine technologies. This contribution from interconnectors is assumed to come mainly from low-carbon sources which could be a timely contribution to system decarbonisation as it ameliorates the challenges of intermittent generation, especially with no unabated fossil fuel generation in the mix by 2050. While the contribution from mature and third generation technologies, such a wave and tidal, appears to be insignificant compared to CCS, offshore and nuclear (see Figure 4.8), their role in enhancing diversity in supply cannot be underestimated.

4.2.4 The economic implications of a revised new UK energy policy on technology deployment post 2030

The challenge to decarbonise the UK economy, and to keep it on track to the 2050 emission reduction target, is highly dependent on the speed at which emissions are reduced in the electricity supply sector. The timely development and deployment of low-carbon energy technologies in the generation mix is fundamentally important if a cost-effective decarbonisation process is to be achieved in the power sector and in other sectors of the economy. The cost of developing a low-carbon electricity sector is influenced by a wide range of factors, but continuity in the energy policy framework is essentially vital in attracting investors as well as de-risking investments in the energy sector. The lack of coherence, stability and clarity in any energy policy framework seeking to balance the challenges of sustainability, security and affordability has a potential to increase the cost of attaining these policy priorities. As the timelines for achieving the deployment of essential low-carbon energy technologies, electricity supply sector decarbonisation targets and the carbon budgets by 2030 are set to be missed by a wider margin, a revised energy policy strategy to steer the UK economy, and indeed the electricity supply sector back on track to the 2050 emission reduction target could have huge economic implications.

An accelerated low-carbon energy technology transition from 2030 to 2050 could culminate in the installed generation portfolio shown in Figure 4.7 with the capability to align with the carbon budgets and the 80 % emission reduction target by 2050. Since the results of the electricity generation infrastructure evolution by 2050 depicted in Figure

4.7 is a product of a delayed and fast tracked decarbonisation process, the low-carbon investment implications are assessed in the context of the total capital investment outlined in Figure 4.9. Before the UK government revised its energy policy framework, it was suggested that an estimated £200 billion investment was required to deploy 45 GW of low-carbon energy capacity between 2014 to 2030 to achieve a carbon intensity of 50 gCO_2/kWh by 2030 (CCC, 2013a). A policy departure from the target of decarbonising the electricity supply sector from 2014 to 2030, to one seeking to pursue an accelerated alternative to achieve a near zero grid carbon intensity by 2050 would require an investment outlay of £237 billion for the generation portfolio assembled in Figure 4.7. Through this radical emission reduction campaign after 2030, investment in conventional large-scale nuclear reactors could potentially reach £56 billion for the estimated 19 GW deployable capacity by 2050. Similarly, a total rollout of 19 GW of SMR could be achieved through an investment portfolio of £73 billion taking the total nuclear power investment to £130 as shown in Figure 4.9.

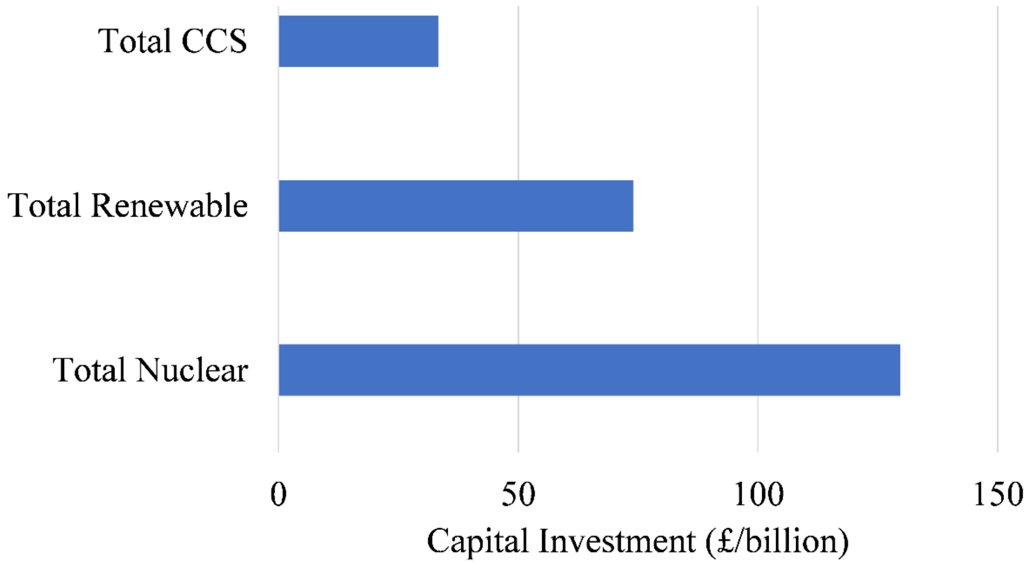

Figure 4.9. The low-carbon and renewable energy investment portfolio for an accelerated electricity supply sector decarbonisation from 2030 to 2050.

A delay in the deployment of CCS in the electricity generation beyond 2030 is estimated to have the potential to increase the cost of carbon abatement to the UK economy. There are suggestions that stronger and comprehensive regulatory frameworks and schemes, such as the a carbon price should be sufficient to incentivise and accelerate CCS deployment in the power sector (Lipponen et al., 2011). According to the analysis performed by the ETI, a delay in CCS development and deployment could increase the longer term decarbonisation cost by about £4-5 billion per year, especially if CCS is rolled out after the 2030s (Clarke, 2016). The CCS installed capacity outlay projected in Figure 4.7 could require a total of £33 billion reflecting all retrofitted applications on gas and biomass plants (see Figure 4.9). The rapid development of the renewable energy sources, particularly offshore is critically important in contributing towards a rapid decline in emissions in the period to 2050.

Based on the simulations undertaken to develop scenarios for this thesis, the rapid development of offshore wind could trigger a fall in the deployment cost to £78/MWh by 2050, making it significantly cost competitive among mature renewable energy technologies at the CfD auctions. The decline in the industrial costs for offshore wind projected in 2050 is in line with the high offshore wind scenario which predicts a fall in costs to around £95/MWh through the 2020s based on the central demand and a decarbonisation assumption of 100 gCO_2/kWh by 2030 (HM Government, 2013b). Based on this indicative LCOE trajectory of £78/MWh, the deployment outlay for offshore wind (see Figure 4.7) could amount to £23 billion, and thus taking the total renewable technology capital input resource to about £74 billion as shown in Figure 4.9. Developments in onshore wind and solar are slightly constrained in this scenario, and thus their capital costs respectively amount to 8 and 11% of the overall renewable energy capital investment compared to 32 % for offshore wind.

4.3 Summary

The UK requires a balanced energy policy framework that meets security of supply and environmental sustainability particularly in the period to 2030. The imminent closure of coal and aging nuclear power plants through the 2020s could potentially create a supply gap of 45–55 % (Institution of Mechanical Engineers, 2016). The new UK energy policy (DECC, 2015a) which is set to be driven by gas and nuclear power plants may not achieve the deployment targets anticipated to meet security of supply and decarbonisation objectives. The potential failure by the new UK energy policy to address the capacity crunch through the 2020s could prolong coal generation in the mix beyond the 2025 phase-out date (DECC, 2015a). This could compromise on the decarbonisation agenda especially in the absence of CCS in the generation mix.

The scenarios developed in this research show that the new UK energy policy may not achieve the 4th and 5th carbon budget requirements (CCC, 2013a; CCC, 2015). An alternative scenario which retains coal and diesel generators could meet the electricity demand at the expense of 81.4 $MtCO_2$ cumulative emissions by 2030. Therefore, the UK new energy policy would need to be revised in order to reconnect with the ethos of the Climate Change Act which seeks to build a strong link between security of supply and a low-carbon electricity supply system. A revised energy policy framework which promotes an accelerated deployment of CCS, conventional and SMR nuclear plants and renewable energy technologies after 2030 could assist in developing a near zero carbon grid intensity electricity generation sector by 2050. This twenty year decarbonisation campaign could be achieved through a £237 billion investment.

Chapter 5 The UK Shale gas development and its implications on the electricity supply system

5.1 Introduction

This chapter presents a detailed analysis of the potential impact of the UK shale gas development on the electricity sector as it transitions towards a low-carbon future by 2050. This assessment is performed in the context of three decarbonisation frameworks that are likely to be adopted by the UK government by 2030 as it seeks to drive down GHG emissions within the electricity generation sector. The shale gas phenomenon and its likely impact on electricity generation, and indeed on the UK energy policy is explored under the 50, 100 and 200 gCO_2/kWh potential decarbonisation targets likely to be legislated by 2030. The scenarios developed under these decarbonisation frameworks incorporate both conventional and unconventional gas in electricity generation with the view of exploring the potential role of shale gas in the generation mix and its wider implications on policy, technology and the economics of steering the electricity sector on the path to the 2050 target as well as in supporting emission reductions in other sectors of the economy.

The shale gas 'revolution' in the United States has resulted in a coal-to-gas fuel electricity switching facilitated by high volumes of gas produced from shales and other unconventional reserves (Rogers, 2011). Following the boom in unconventional gas production in the US, the proportion of electricity generated from gas has increased from 18.8 % to 24.8 % whilst that from coal declined from 49.6 % to 42.2 % in the period 2005 to 2012 (Broderick & Anderson, 2012). Although the US experience in the unconventional gas development and its implications on the energy system are not likely to be replicated in the UK, comparative analysis presented in this chapter seek to explore the role of conventional and unconventional gas in electricity generation under the three decarbonisation frameworks. In the absence of coal in the generation mix by 2030, the focus of this chapter is devoted to assessing the impact of conventional and unconventional gas on the development and deployment of low-carbon energy technologies required to steer the UK economy on the path to the 80 % emission reduction target by 2050. A detailed assessment of the implications of using either conventional or unconventional gas on low-carbon energy technology uptake under the different decarbonisation ambitions is explored in the following subsections. The extent to which gas fossil resources are utilised in electricity generation under the three decarbonisation pathways could have significant impacts on renewable energy and low-carbon technology investments. The focus of this chapter is to quantify the level of low-carbon and renewable energy technology development and the investment that could potentially be realised under scenario assessments constructed based on the 50, 100 and 200 gCO_2/kWh grid intensity targets with natural and shale in the generation mix. It is through these scenarios that the impact of the shale gas development on the electricity supply system and the future direction of the UK energy policy can be characterised in the context of the decarbonisation rhetoric set for 2030.

5.2 Conventional and unconventional gas use in electricity generation

The CCC suggested that any path to an 80 % emission reduction target by 2050 requires that the electricity generation is almost entirely decarbonized by 2030 (CCC, 2013a). Therefore, the ‘path to 50 g’ decarbonisation framework seeks to reduce the carbon grid intensity from the current 500 g/kWh to 50 g/kWh by 2030 (CCC, 2010). Decarbonising the electricity sector is viewed as the most effective way of rapidly reducing emissions as it reduces pressure on other sectors of the economy to decarbonise. On the other hand, the ‘path to 100 g’ decarbonisation target is perceived by government as ‘Plan B’, a pathway likely to be adopted if low-carbon energy technology costs fall less quickly than anticipated or achievable technology build rates are lower than expected (CCC 2013c).

A 200 gCO_2/kWh decarbonisation target by 2030 is another emission reduction path that has been used by the government to inform the energy policy, particularly on the future role of gas in the generation mix (DECC, 2012c). The recent shift in the energy policy sets energy security at the top tier of the UK energy policy objectives, and thus presents gas as a technology that could define the energy supply landscape for the UK future because of its assumed capacity to mitigate electricity demand and climate change challenges (DECC, 2015). The official position of the UK government with regards to the direction of the new energy policy is that of building more gas and nuclear plants and maybe offshore wind provided deployment cost comes down (DECC, 2015). In the context of this new energy policy paradigm, the case for including a 200 gCO_2/kWh pathway by 2030 within the decarbonisation frameworks can be contemplated. However, the prospects of steering the power sector on a cost-effective path to 2050 is inconceivable under the 200 gCO_2/kWh decarbonisation target.

At the backdrop of the anticipated nuclear and coal power plant closures by 2023 and 2025 (World Nuclear Association 2015a; DECC 2015a), the prospects of adopting a 200 gCO_2/kWh grid intensity by 2030 is becoming highly likely, especially in the absence of an immediate replacement capacity in the form of new nuclear power, gas, offshore wind and CCS development. However, the 200 gCO_2/kWh decarbonisation target by 2030 could hardly come as a surprise to the UK energy policy discourse as it was used to inform and support the UK government's position in projecting the importance of gas in the UK future electricity supply system (DECC, 2012c).

Also, it can be argued that with the increased phase-out of renewable energy subsidies on onshore wind and solar PV (DECC, 2015c; DECC, 2015b), the prospects of achieving deep cuts in emissions by either 50 or 100 gCO_2/kWh by 2030 could be highly ambitious, and hence the inclusion of a 200 gCO_2/kWh grid intensity as a potential decarbonisation target likely to be adopted in the power sector by 2030. All the scenario assessments presented in this thesis incorporate the impact of the cost of carbon as projected in the carbon price floor (CPF) up to 2030. As a mechanism designed to drive investment in low-carbon and renewable energy technologies, the inclusion of the CPF as one of the key input parameters in the scenario assessments could assist in determining the level of low-carbon technology penetration in the UK electricity generation mix. Also, the high carbon cost projected to 2030 could play a vital role in assessing the attractiveness of gas use in unabated gas plants for electricity generation.

5.2.1 Electricity generation transition under the 50 gCO_2/kWh trajectory

For the purpose of this thesis, scenarios used in this assessment are named based on the nature or type of gas resource used in electricity generation and the decarbonisation trajectory pursued. Hence scenarios seeking to achieve a carbon grid intensity of 50 g/kWh using natural or shale gas are referred to as Natural Gas 50 (N/Gas50) or Shale Gas 50 (S/Gas50). On the other hand, scenario assessments adopting a 100 or 200 gCO_2/kWh grid intensity using natural or shale gas are identified as Natural Gas 100 or 200 (N/Gas100, N/Gas200) and Shale Gas 100 or 200 (S/Gas100, S/Gas200), respectively. These scenarios are used to define the evolution of the UK electricity generation landscape under the influence of a policy framework that incorporates shale gas use in the electricity supply systems.

Transition pathways under the 50 g/kWh decarbonisation framework are projected from 2010 to 2050 with a view to explore the level of technology development, investment and emission reduction trends resulting from the use of shale gas in electricity generation. The transition of the UK energy generation sector is examined based on the 2020, 2030 and 2050 milestones which are important landmarks defining the UK energy policy. These milestones respectively represent the EU renewable energy target, the decarbonisation of the electricity supply sector and the 2050 emission reduction target. Therefore, it is important to trace the evolution of the UK electricity supply sector based on these important landmarks. In the context of this transition framework, Figure 5.1 shows the development of the UK electricity generation sector under the ‘path to 50 g/kWh’ carbon grid intensity by 2030 with unabated natural gas in the generation mix. The low-carbon and renewable energy deployment in the N/Gas50 scenario respectively account for 9.9 and 46.4 GW in 2020. The penetration of renewable energy technologies reach 42 % of the total installed capacity, which surpasses the 15 % renewable energy target set by the EU to be achieved by the UK energy supply sector. The low-carbon technology capacity outlay during this period remains low as CCS is still at demonstration stage.

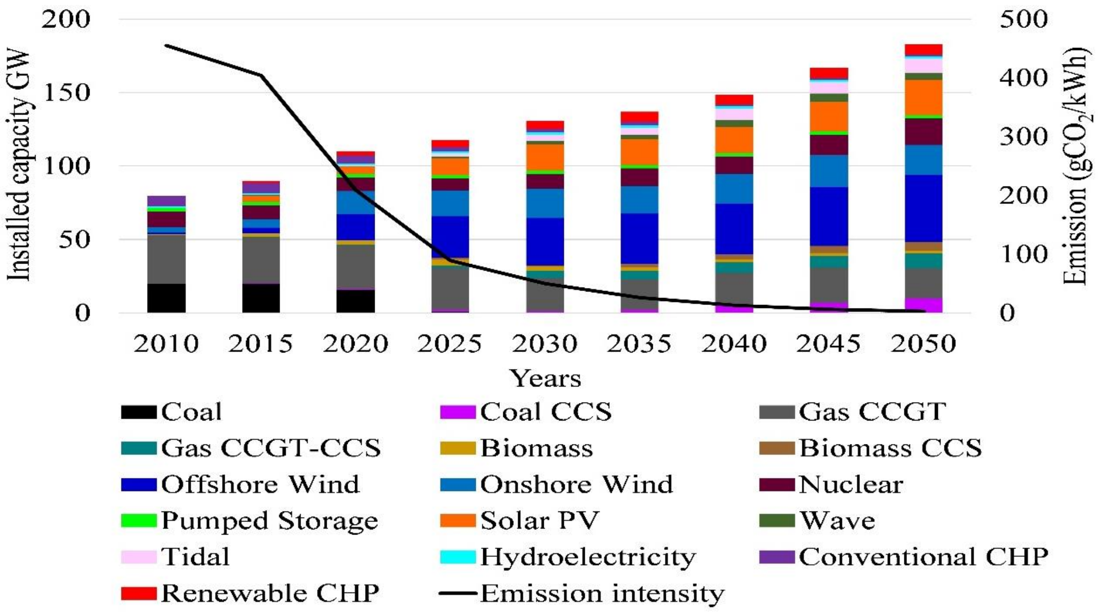

Figure 5.1. The installed electricity generation capacity–N/Gas50 scenario.

However, as the countdown to sector decarbonisation and a near zero emission target by 2030 and 2050 is respectively approached, the level of low-carbon and renewable energy deployment increases to reach 103.5 and 158.9 GW, as shown in Figure 5.1. The deployment outlay for low-carbon and renewable electricity generation technologies achieved in this scenario is a result of the 17 GW and 86.5 GW, 43.8 and 115.2 GW capacity deployment in 2030 and 2050, respectively as highlighted in Figure 5.1. In response to this ground-breaking low-carbon and renewable energy development (in 2030 and 2050), the electricity supply sector achieves a 50 and 3 gCO_2/kWh intensity as shown by the emission trend in Figure 5.1. The dominance of low-carbon and renewable energy technologies through this transition period reduces the operation regime of unabated gas plants in the mix, and hence the achievement of the emission targets set. High volumes of low-carbon and renewable energy deployment during this transition period capture the results of a low-carbon driven policy framework which seeks to balance the requirement to mitigate climate change while ensuring security of supply and the provision of affordable electricity to consumers. The technology deployment presented in Figure 5.1 characterise a policy undertaking which embraces the "trilemma of energy sustainability" devoted to promoting energy security, social security and environmental impact mitigation (World Energy Council, 2012).

The S/Gas50 scenario shown in Figure 5.2 follows a similar trend to that displayed in Figure 5.1. The technology development is similar up to 2020 as both pathways use natural gas in their generation portfolio as shale gas is presumably under exploration. Renewable energy technology deployment in 2020 results in 46.4 GW of installed capacity with offshore and onshore wind accounting for 72.6 % of the renewable energy technology build-up. The substantial surge in offshore wind (18 GW) during this period is consistent with the notion that such a level of deployment could assist the UK in meeting the EU 2020 renewable energy target (Heptonstall et al., 2012). In 2030 and 2050, the S/Gas50 scenario has a cumulative low-carbon and renewable energy penetration of 101.9 and 159.1 GW capacity, respectively. There is a 1.7 GW renewable energy installed capacity difference between N/Gas50 and S/Gas50 which is simply induced by the reduced emission factor and fuel cost applied on shale gas. In both scenarios, unabated gas generation is extremely curtailed due to the deep cuts in emissions that is required to achieve the 50 gCO_2/kWh by 2030 as highlighted in Figures 5.1 and 5.2.

In the absence of high carbon intensive coal in the UK electricity generation mix, electricity generation plants using unabated conventional and unconventional gas operate at very low load factors in the order of 6 to 8 % for the scenarios seeking to achieve a decarbonisation target of 50 gCO_2/kWh by 2030. Meanwhile, CCGT plant capacities in N/Gas50 and S/Gas50 scenarios remain significantly high, that is, 22.6 GW and 22.9 GW as depicted in Figures 5.1 and 5.2. The unabated gas capacity portrayed under this emission reduction framework is reserved for the provision of reliable and flexible back-up supplies to mitigate high levels of intermittent generation in the mix (CCC, 2010). The low-carbon and renewable energy technology outlay for the two scenarios is almost identical, which suggests that the inclusion of shale gas in the electricity generation system would not change the technology deployment ambition or dynamics required to achieve deep cuts in emissions by 2030.

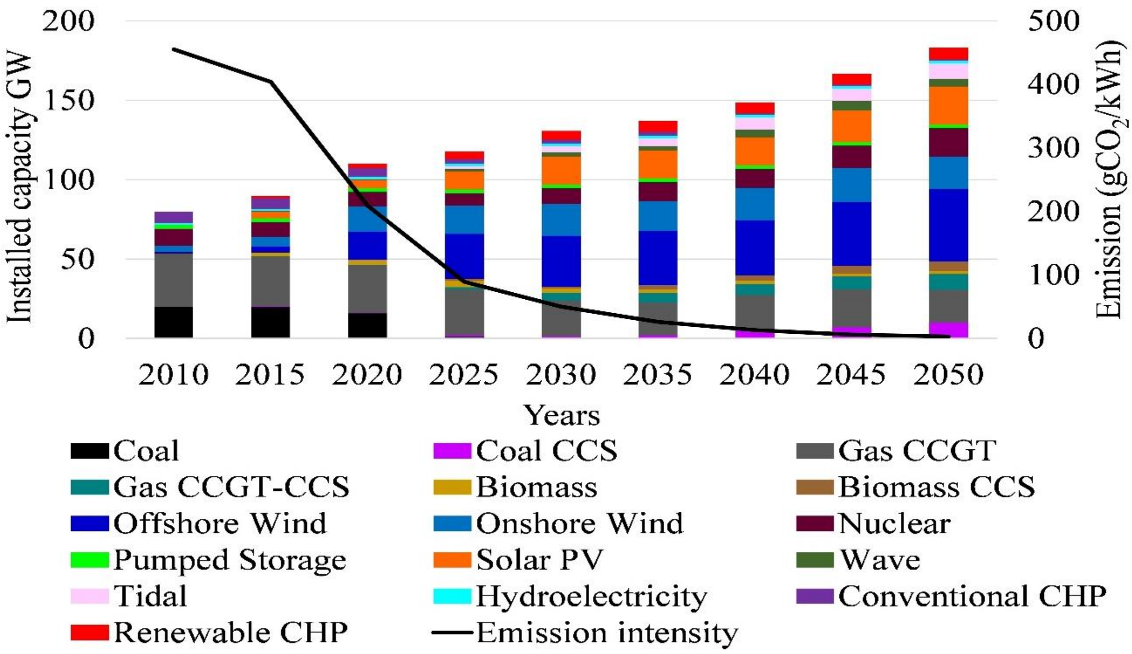

Figure 5.2. The installed electricity generation capacity–S/Gas50 scenario.

The introduction of incentive mechanisms in the form of Renewable Obligation (RO), the exception from climate change levy (CCL) and feed-in-tariffs (FiT) appears to have combined to boost the level of deployment of offshore wind in the UK (Toke, 2011). The favourable investment climate for renewable energy technologies has also been promulgated by a favourable consenting system driven by The Crown Estate (TCE) which owns and leases the near-shore and offshore sea bed up to 12 nautical miles in the UK to offshore wind developers (Mani & Dhingra, 2013). In view of this enabling environment for offshore wind development, 32 GW installed capacity is deployed in the two scenarios by 2030, which is within reach of the government's 'best case' deployment scenario estimated at 39 GW which is also projected in the same period (RenewableUK, 2013).

However, the policymakers appear to have a different perspective on the role of unabated gas vis-à-vis intermittence beyond 2030. The UK government's policy position appears to be that which sees gas as continuing to play an important role in the energy mix well into and beyond 2030 and not only restricted to providing back up to renewables" (CCC, 2012). The adoption and implementation of such a policy perspective could potentially compromise on the wider commitment to decarbonise the energy system as well as on the objective of promoting rapid emission reduction commensurate with keeping global temperature within 2 ^{o}C of pre-industrial levels. Nonetheless, electricity generation output from unabated gas plants portrayed in Figures 5.3 and 5.4 contradicts the government's position and aspirations on gas as it mirrors the expected contribution of gas in an electricity generation infrastructure sector seeking to achieve a near carbon neutrality by 2050. In view of the technology diversity exhibited in Figures 5.1 and 5.2, the electricity generation sector is almost carbon neutral in the period leading to 2050 as the renewable energy installed capacity reaches 115 GW, while the low carbon technologies grow to reach 43.8 GW in the 'path to 50 g' scenarios. This technology combination presented in this decarbonisation framework would literally squeeze out carbon emissions from the electricity sector, thereby allowing the electricity generation infrastructure to achieve a grid carbon intensity of 3 g/kWh in 2050 (see Figures 5.1 and 5.2).

The rollout of onshore wind in N/Gas50 and S/Gas50 respectively achieves a 15.7 GW growth by 2020 and a 20.1 GW and 19.5 GW growth by 2030, as highlighted in Figures 5.1 and 5.2. The deployment milestone achieved in this technology during this transition period to 2030 is a result of the abundant wind resource in the UK and the maturity and proven nature of the technology. However, the prospects of attaining this exceptional growth in onshore wind hinges primarily on policy and the availability of sites (Parkes, 2012). The political willingness and appetite towards the continued onshore wind deployment appears to be ebbing away. It can be argued that the lack of enthusiasm for this technology on the political front could be attributed to the view that the UK's 2020 renewable energy target is almost set to be achieved. In this regard, the seemingly polarised attitude towards onshore wind is encapsulated in the remarks made by the Prime

Minister in which he suggested that the public is basically fed up with wind (RenewableUK, 2014). With the anticipated eradication of subsidies for onshore wind by 2016 (DECC, 2015c), the prospects of achieving the deployment targets portrayed in Figures 5.1 and 5.2 is highly debatable. Nonetheless, the contribution from onshore wind would need to reach the deployment levels exhibited in Figures 5.1 and 5.2 in order to contribute towards achieving the carbon grid intensity commensurate with the ‘path to 50 g’ by 2030.

Similarly, the deployment trend for solar PV, shown in Figures 5.1 and 5.2, depicts a growth at unprecedented levels from 2015 to 2050 to reach 24.1 GW in total capacity. This solar ‘revolution’, particularly in the period after 2010, was a result of the implementation of favourable policies such as the small scale FiT scheme and the RO which in September 2011 alone, saw a total of 15855 installations with a total capacity of 80.5 MW (Muhammad-Sukki et al. 2013). Also, this growth was attributed by the significant reduction in installation costs estimated to have fallen by about 50% between 2010 and 2012 (DECC, 2013c). It was at the backdrop of this growth that solar PV was considered as one of the key renewable energy technologies that can assist in creating a balanced UK energy mix, with a projected 20 GW upper limit capacity to be achieved by 2020 (DECC, 2012d).

However, following the UK government’s decision to close the RO to new solar projects above 5 MW by the 1 April 2015, (DECC, 2015b), it remains to be seen whether the industry has matured enough to compete for funding under the CfD scheme in order to sustain growth in the solar industry up to 2050, as portrayed in Figures 5.1 and 5.2. The UK government continues to consider renewable energy technologies as instrumental in driving a transition to a low-carbon future, and as such, the momentum in the solar energy development and that of other renewable energy technologies would need to be sustained regardless of the withdrawal in government support. The UK government’s confidence in the future performance of the renewable energy industry is borne out of the understanding that support mechanisms are designed to help technologies to move from a demand-led to a competition-led allocation support (FiT CfD) rather than encourage reliance on subsidies (DECC, 2015e).

The increased penetration of both low-carbon and renewable energy technologies portrayed in Figures 5.1 and 5.2 through the 2020s is consistent with the 30 - 70 GW estimated scale of new capacity deployment required by 2030 (HM Government, 2011). The build-up in low-carbon and renewable energy technologies demonstrated in N/Gas50 and S/Gas50 scenarios is 79 % of the total installed capacity by 2030, which is 4 % more than the estimated 75 % generation mix projected by the central scenario that meets the fifth carbon budget (CCC, 2015). The growth in low-carbon and renewable energy portfolio projected for 2030 by the N/Gas50 and S/Gas50 scenarios is earmarked to have a dual impact of replacing the ageing UK's electricity infrastructure, particularly nuclear and coal at the end of this decade as well as laying the foundation for sector decarbonisation through the 2020s. Irrespective of the use of shale gas in one of the scenarios in the 'path to 50 g' pathway, the level of greenhouse gas emission reduction attained is 17.3 $MtCO_2e$ compared to the 17 $MtCO_2e$ achieved by the 'Max' scenario, which represents the maximum feasible deployment capacity of key technologies and functional market mechanisms necessary to achieve a 50 g carbon grid intensity by 2030, as described in the fifth carbon budget (CCC, 2015).

The role of nuclear power and CCS in achieving the emission intensity trend, shown in Figures 5.1 and 5.2, is indispensable. Both scenarios project new nuclear power deployment to reach 8.7 GW and 18 GW by 2030 and 2050, respectively. The nuclear power projection outlined in these scenarios has been set below the ambitious estimates aspired by industry, where a 16 GW capacity of nuclear energy was prospectively targeted for 2030 (HM Government, 2013). In recognition of the important role of nuclear power in delivering secure, low-carbon and affordable energy for the future (HM Government, 2013a), the UK government has identified and approved eight potentially suitable sites for the development of new nuclear power plants (DECC, 2011b), with a combined capacity of 23 GW (Pöyry, 2013). Thus, the rollout of new nuclear capacity presented in the scenario assessments presented in this thesis took into account the potential investment, technical and planning barriers and uncertainties that could delay or derail the ambition to achieve the potential deployment targets anticipated. On the other hand, CCS outlay to 2030 is projected to reach 7.1 GW with high prospects of attaining a total capacity of 26 GW by 2050, in order to develop a near zero carbon emission sector by 2050 (see Figures 5.1 and 5.2). The level of CCS deployment outlay projected by the 'path to 50 g' scenarios by 2030 is below the 10 GW capacity target estimated by the UK government (DECC, 2012a) due to uncertainty on economic and technical viability of the technology.

The level of development of new nuclear power capacity projected in these scenarios is anticipated to be driven by the CfD mechanisms, which, if successfully implemented could be a game-changer in guaranteeing viability to low-carbon investment, a key driver in financing a portfolio of low-carbon technologies necessary for the electricity supply decarbonisation. The deployment outlay for nuclear power and CCS presented in N/Gas50 and S/Gas50 could certainly achieve the decarbonisation target set in each scenario. However, there is uncertainty over the capacity of the current policy to deliver the projected capacities on time and budget to contribute towards sector decarbonisation through to 2050. As for nuclear power, the level of uncertainty over the potential build rates can be attributed to what Mez (2012) observed as the consistently rising costs and associated problems of financing nuclear power plants and the shortage of technical expertise. These factors, combined with the traditional concerns for accidents and radiation risks and nuclear waste management (Teräväinen et al., 2011), have a greater potential to stall momentum in both investor interest and the actual deployment of the technology. In the context of these constraints, and the on-going delays currently facing UK's first new nuclear plant (Hinkley Point C), an estimated capacity of 8.7 and 18 GW of new nuclear portrayed in Figures 5.1 and 5.2 could contribute towards achieving the decarbonisation aspirations set by the government to 2050.

CCS, as a new technology that removes CO_2 from the atmosphere, involves either pre-combustion or post-combustion separation of CO_2 in either new or retrofitted plants, and thus leading to an energy system with negative emission characteristics (Read & Lermit, 2005). Retrofitted CCS on fossil fuel and biomass plants account for 7.1 GW of installed capacity in 2030, and 70 % of this capacity constitutes gas-fired plants, with the remaining proportion constituting coal and biomass plants fitted with CCS. The application of CCS technology on biomass power plants has a unique potential to create simultaneously CO_2 negative emissions (IPCC, 2005) without which could be extremely costly and difficult, if not impossible to reach emission targets below 450 ppm (Azar et al. 2006). However, due to its technical and economic uncertainty, CCS development in the UK is still a challenge as it hasn't been deployed at a commercial scale. The technology is still at demonstration stage and the full chain technology has not yet been demonstrated on a working power station or industrial facility in Europe (DECC, 2014a). A new twist in the development of the UK energy policy has unfortunately culminated in the cancellation of funding for the demonstration and commercialisation of CCS programmes by the UK government. Therefore, this implies that CCS technology may not be part of the UK generation mix by 2030. However, for the purpose of this thesis, some developments within the UK electricity supply system are simulated with the assumption that the UK government still supports the technology and still considers it as an integral part of the decarbonisation framework.

The 50 g/kWh carbon grid trajectory by 2030 represented by the N/Gas50 and S/Gas50 scenarios reflect a greater alignment to the Paris 21st Conference of Parties (COP21) agreement pledging to hold the increase in the global average temperature well below 2 ^{o}C pre-industrial levels and pursuance of efforts to limit the temperature increase to 1.5 ^{o}C above pre-industrial levels (UNFCCC 2015). The deep cuts in emissions accomplished by the technology outlay projected in Figures 5.1 and 5.2 is in-keeping with the EU's collective 2030 pledge to reduce emissions by at least 40 % compared to the 1990 levels and the 27 % share of renewable consumption (European Commission, 2014). The 50 gCO_2/kWh decarbonisation framework represents a policy ambition which demonstrates the important role of offshore wind alongside nuclear and CCS in driving down emissions within the power generation sector. However, the potential to achieve the emission trajectory exhibited in Figures 5.1 and 5.2 is dependent on the capacity of policy instruments to overcome barriers and uncertainties that affect technology and energy-related market developments. While the 50 g/kWh carbon grid intensity could be highly ambitious in the context of the current UK electricity generation landscape, the target is achievable provided the energy policy position remain consistent and resolute to meeting national, regional and global climate change commitments.

The electricity generation output from the scenarios under a 50 gCO_2/kWh decarbonisation trajectory follow a similar trend for all the technologies in the mix except in unabated gas plants. The influence of a reduced emission intensity in shale gas of 423 gCO_2/kWh compared to 488 gCO_2/kWh in natural gas (DECC, 2013b; POST, 2011), accounts for the increase in the amount of electricity generated from shale gas as shown in Figures 5.3. As a result of the increased generation from shale gas in S/Gasd50, the respective contribution from low-carbon and renewable energy technologies stands at 188.9 TWh and 260.6 TWh in 2030 and 2050 as shown in Figures 5.3.

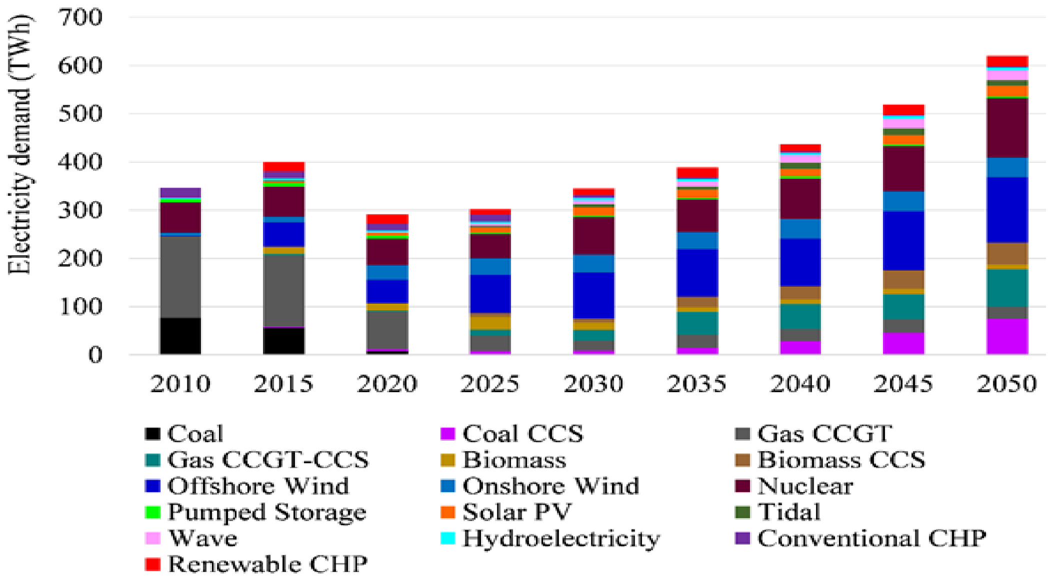

Figure 5.3. The total electricity generation output for the S/Gas50 scenario from 2010-2050.

A high carbon emission intensity in conventional gas reduces the electricity output from gas generation, and hence the marginally higher generation from low-carbon and renewable energy technologies. As shown in Figure 5.4, electricity supply from low-carbon and renewable energy technologies account for 196.5 TWh and 272.6 TWh, respectively. This high level of intermittent renewable generation is balanced by a baseload electricity generation output from nuclear and CCS in the order of 322 TWh and 123.5 TWh, 320.7 TWh and 126.7 TWh in 2030 and 2050 as highlighted in Figures 5.3 and 5.4, respectively. The electricity generation output from low-carbon technologies is combined with output from pumped storage and unabated gas CCGT and CHP to mitigate any potential supply deficit created as a result of variable supply from renewable energy sources such as wind, wave and solar.

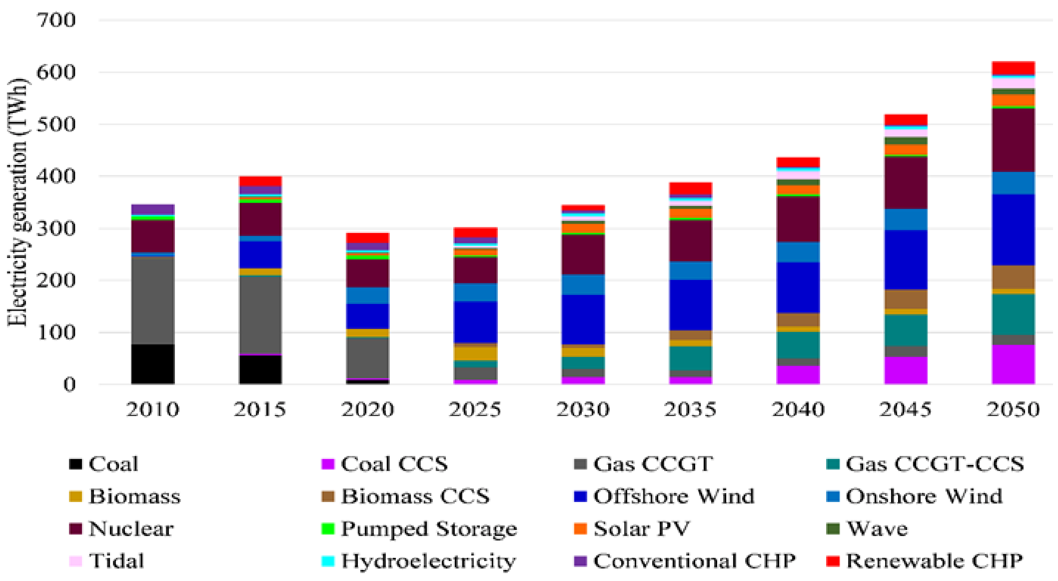

Figure 5.4. The Total electricity generated for the N/Gas50 from 2010–2050.

5.2.2 The 2030 electricity generation infrastructure outlook under a 100 and 200 gCO_2/kWh pathway

The current emission intensity of the UK electricity generation sector is 450 gCO_2/kWh (CCC, 2015). In that sense, the adoption of a 100 gCO_2/kWh decarbonisation target by 2030 is deemed by the CCC (2015) to be on the cost-effective path to achieving the 80 % GHG emission reduction by 2050. As in the 'path to 50 g' outlined in Section 5.2.1, the N/Gas100 scenario has a high penetration of low-carbon and renewable energy technologies commensurate with the requirement to promote deep cuts in emissions in order to achieve a 100 gCO_2/kWh emission intensity level. By 2030, the low-carbon energy technology deployment capacity in N/Gas100 reaches 16.7 GW while renewable energy technology penetration reaches 71.9 GW (see Figure 5.5). This capacity outlay in renewable energy technologies is significantly higher than that in S/Gas100 where the increased electricity generation (54.2 TWh) from unabated shale gas allows about 68.8 GW renewable energy capacity in the mix (see Figure 5.5). The low-carbon and renewable energy technology growth in the 'path to 100 g' scenarios achieves 75 % share of generation by 2030, a generation mix which is consistent with the central scenario developed to inform the fifth carbon budget (CCC, 2015).

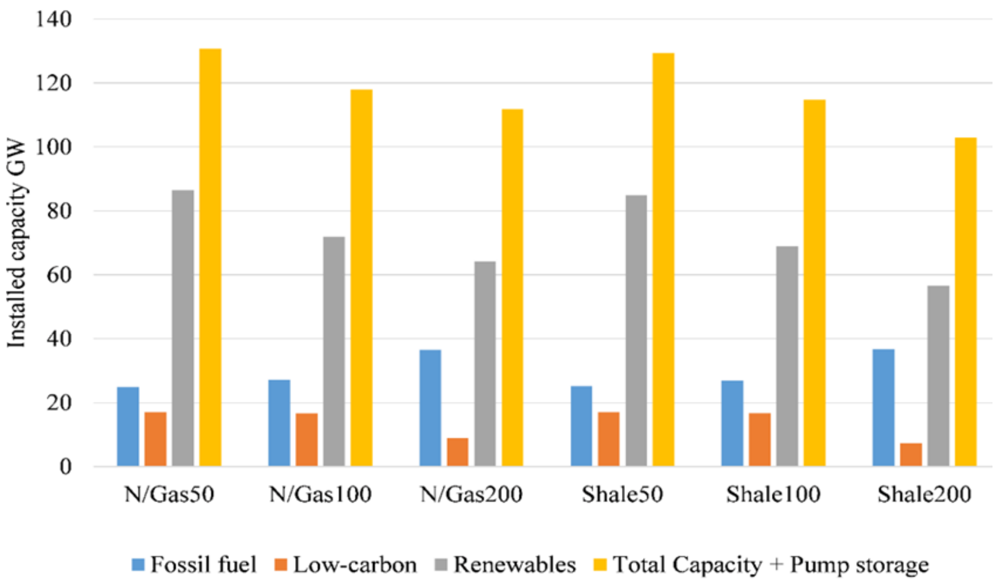

Figure 5.5. The technology penetration in 2030 under different decarbonisation pathways.

The ‘path to 200 g’ scenarios is representative of an electricity generation sector facing delays in the development and deployment of low-carbon energy technologies such as nuclear and CCS. A dash for new gas plants, new nuclear power plants and possibly offshore wind define the direction of the new UK energy policy framework. In its pursuance of energy security, the new energy policy narrative also encourages investment in shale gas exploration to reduce import gas dependency. In justifying their recommendation for the commencement of exploratory drilling for shale gas, the UK Task Force on Shale Gas (2015) argues that it is not feasible to create a renewable energy industry that can meet all energy needs in the short-term, and hence shale gas presents an environmentally cleaner alternative to coal. While this assessment is undoubtedly true, the level of unabated gas generation in the N/Gas200 and S/Gas200 scenarios standing at 36.5 and 36.7 GW capacity as portrayed in Figure 5.5 does not only limit the penetration of low-carbon and renewable energy technologies, but it increases the risk of the electricity generation sector being locked-in fossil fuel generation infrastructure. The low-carbon and renewable energy development in the ‘path to 200 g’ scenarios respectively achieve 8.8 and 7.3 GW and 64.2 and 56.6 GW, for the N/Gas200 and S/Gas200 as shown in Figure 5.5.

In the context of the current UK electricity generation infrastructure development, Figure 5.6. indicates that the proportion of nuclear power capacity in this low-carbon portfolio (N/Gas200 and S/Gas200) is limited to 4.3 GW by 2030, which in this case comprises of a 3.2 GW new nuclear plant, Hinkley Point C, which is expected to be on line potentially by 2025 (DECC, 2015a; World Nuclear Association, 2015b) and a 1.198 GW remnant capacity from the old fleet which is set to be decommissioned in 2035 (World Nuclear Association, 2015b). The projected new nuclear power capacity is based on the assumption that only one plant could be commissioned in the period to 2030. The deployment outlay for CCS demonstrated in the 'path to 200 g' scenarios is up by 3.5 GW in 2030 (see Figure 5.5) which is unlikely to reflect the 'serious deployment' judged by the Task Force on Shale Gas to be essential for the medium-term viability of any significant shale gas industry (Task Force on Shale Gas, 2015). The CCS deployment outlay projected in the 'path to 200 g' pathway is likely to be lower or none at all following the UK government's decision to cancel the £1 billion capital investment for CCS competition (DECC, 2015d)

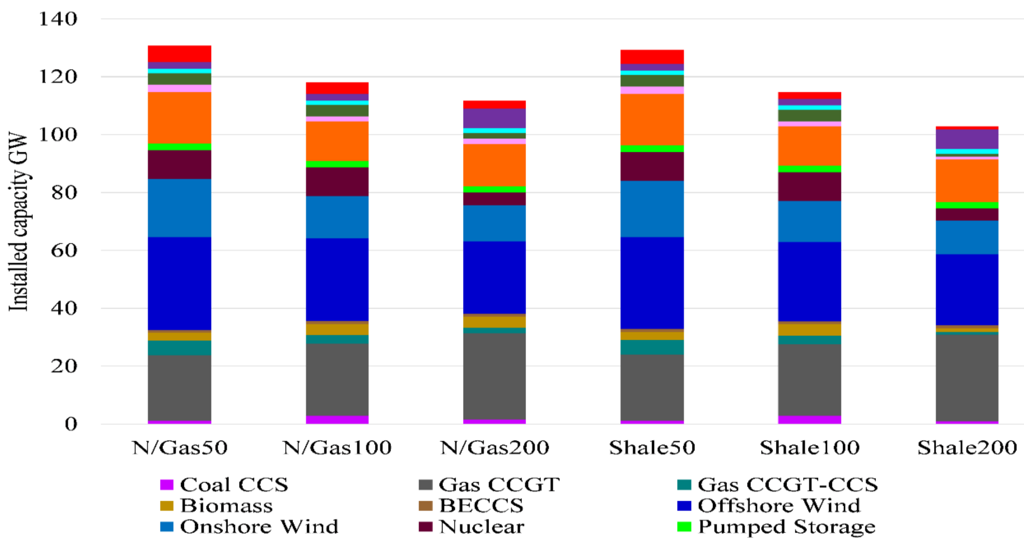

Figure 5.6. The 2030 technology deployment under the different decarbonisation pathways.

A higher emission intensity of conventional gas in N/Gas100 results in a 46.9 TWh generation outlay compared to 54.2 TWh in S/Gas100, and hence the marginal difference in the proportion of technology deployment and the resultant electricity generation output portrayed in Figures 5.6 and 5.7. Furthermore, the rollout of low-carbon energy technologies in S/Gas100 is 16.7 GW, which is 1 GW less than that in N/Gas100 owing to the impact of using shale gas in electricity generation as highlighted in Figure 5.6. The emission reduction achieved by the 'path to 100 g' scenarios is 34.5 $MtCO_2e$ compared to the 31 $MtCO_2e$ achieved by the Central scenario developed to inform the fifth carbon budget by the Committee on Climate Change (CCC, 2015). It is observed that the introduction of shale gas in the UK electricity generation mix would have limited impacts on emissions reduction under the 100 gCO_2/kWh decarbonisation framework which is aligned to the carbon budgets. The inclusion of shale gas in the electricity supply mix would not change or hinder the development and deployment of low-carbon and renewable energy technologies as demonstrated by the small difference in the level of capacities attained in the two scenarios.

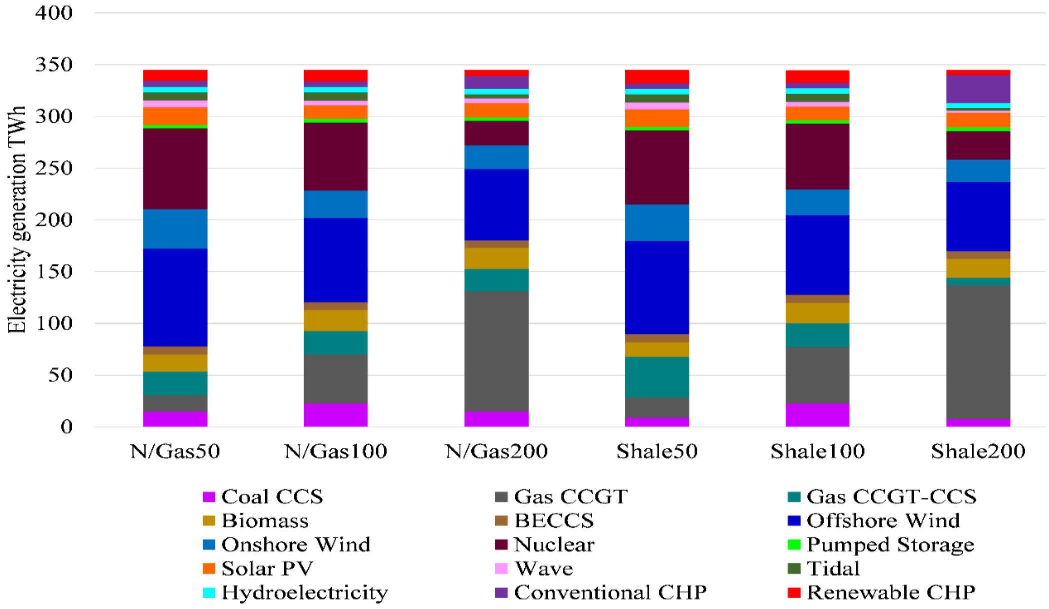

Figure 5.7. The 2030 electricity generation output for the different decarbonisation pathways.

Unabated conventional and shale gas plants in N/Gas200 and S/Gas200 scenarios are operated at 42 % and 55 % load factors. As a result of the favourable conditions for gas generation, a higher electricity generation output in the order of 108 TWh and 142.8 TWh is achieved in N/Gas200 and S/Gas200 in 2030 as depicted in Figure 5.7. The scale of low-carbon and renewable energy technology deployment is severely curtailed following the increase in electricity generation from gas in these two scenarios. The low-carbon deployment profile in N/Gas200 and S/Gas200 is 50 % that of the path to ‘50 and 100 g’ scenarios as shown in Figure 5.5. The ‘path to 200 g’ limits the deployment of renewable energy technologies as indicated in Figure 5.5, where N/Gas200 records a total of 64.2 GW while as 56.6 GW is deployed in S/Gas200 by 2030. The emergence and development of shale gas is not expected to hinder or slow the momentum in the development and deployment of low-carbon and renewable energy technologies. Instead, the government is being argued to invest revenues derived from a developed shale gas industry to fund research and development and innovation in CCS and other low-carbon energy technologies (Task Force on Shale Gas, 2015). The deployment outlay for low-carbon energy technologies in N/Gas200 and S/Gas200 reaches 8 % and 7 % while the renewable energy technology penetration attained is 57 % and 55 % by 2030, respectively.

The energy generation mix outlook portrayed by the 'path to 200 g' scenarios is not consistent with the goal of achieving the 80 % emission reduction target by 2050. A 200 gCO_2/kWh decarbonisation target by 2030 results in the production of 68.9 $MtCO_2e$ compared to 34.5 and 17.3 $MtCO_2e$ for the 'path to 50 and 100 g' emission reduction frameworks, respectively. The emissions performance of the 200 gCO_2/kWh scenarios is not close to the 40 $MtCO_2e$ emission target achieved by the Committee on Climate change's Barriers scenario, a fifth carbon budget scenario representing unfavourable technological and market barriers to power sector decarbonisation by 2030 (CCC, 2015). The carbon grid intensity achieved by the Barriers scenario is 116 g/kWh, which is attributed by a renewable energy deployment outlay that is 13.9 % less than the capacity level achieved in the N/Gas100 scenario. Most importantly, the electricity generation portfolio presented by the 'path to 200 g' by 2030 fulfils the security of energy supply objectives pursued by the energy policy, but it does not meet the carbon emission budgetary requirements set by the Climate Change Act. Therefore, the adoption of the 200 g/kWh carbon grid intensity by 2030 implies that the power sector could fail to reduce emissions in line with the estimated cost-effective path (carbon intensity below 100 gCO_2/kWh) to the legislated 2050 emission reduction target. Under these circumstances, it means that the power sector may fail to support other sectors of the economy in reducing emissions in order to remain on track to the 80 % emission reduction by 2050 relative to the 1990 levels.

The new UK energy policy framework (DECC, 2015a), which is set to be driven by gas, nuclear and potentially offshore wind, prioritises security of supply above climate change, and thus can be envisaged under the 200 gCO_2/kWh emission trajectory. Whatever the circumstances, a scenario narrative built on the 'path to 200 g' does not align with the pledge to limit annual emissions of greenhouse gases to a level consistent with the target of holding the increase in the global average temperature to well below 2 °C pre-industrial levels and the pursuance of efforts to limit the temperature increase to 1.5 °C pre-industrial levels agreed at the Paris COP21 (UNFCCC, 2015). There appears to be a disconnect between the UK government's new energy policy 'reset' and its high-level commitment to tackle climate change as demonstrated by its strong stance in the EU, at the COP21 climate change summit and its continued support for the Climate Change Act. In the event that the new energy policy 'reset' adopts the 'path to 200 g' emission reduction target, it would be extremely difficult for the UK government to fulfil the fifth carbon budget (2028-2032) requirements, which proposes the adoption of a low-carbon power policy consistent with reducing carbon intensity of the power sector to below 100 gCO_2/kWh in 2030 compared to 450 gCO_2/kWh in 2014 and 200-250 gCO_2/kWh expected in 2020 (CCC, 2015).

5.2.3 Unabated gas generation regime and the cost implications

The operation of unabated gas plants under the different decarbonisation trajectories has huge implications on both the levelised cost of electricity from CCGT plants and the level of capacity likely to be retained on the system to boost security of electricity supply objectives. The introduction of the carbon price support (CPS), a policy designed to impose a penalty on fossil fuel generation could affect the economics of gas generation. The increase in the cost of carbon could escalate the cost of the electricity generation from gas plants, and thus impacting on their role in the generation mix, either as back-up capacity to variable renewable energy sources, particularly on the 'path to 50 and 100 g' scenarios or in providing baseload generation as in 'path to 200 g' scenarios.

The LCOE for the different technologies that characterise the scenario assessments in this thesis is shown in Figure 5.8. This LCOE indicator projected in Figure 5.8 is based on the medium cost estimate of the capital investment and the operation and maintenance for energy technologies as indicated in Table.3.4. The LCOE outlay incorporates the 2030 projected carbon floor price (CFP) of £76/tCO_2 (DECC, 2013e), which is likely to increase the cost of electricity generation from utilities using unabated conventional and shale gas fuel resources. The UK government has imposed a cap on the carbon floor price to a maximum of £18/tCO_2 from 2016/17 until 2019/20 (HM Revenue & Customs, 2014) a measure intended to limit any competitive disadvantage British companies face in the global market place.

The ability of the UK government to intervene in the future development of the carbon price has further heightened the level of uncertainty that is likely to affect the carbon pricing regime by 2020. To this end, some of the scenario assessments presented in this thesis have been built on the assumption that the 2016/17 to 2019/20 capped carbon floor price could be extended to 2030. The potential carbon price cap extension up to 2030, as investigated in this thesis, could possibly be used as part of an incentive mechanism likely to promote the new gas plant infrastructure development sought by the UK government in support of its proposed new energy policy 'reset'. The impact of a carbon freeze on the cost of electricity for the conventional and unconventional gas plants is shown in Figure 5.8, where the LCOE is about one third of the full projected carbon price by 2030. The capping of the carbon floor price in the scenarios pursuing radical emission reduction does not change the operational regime of the gas plants which continue to operate at very low capacity factors, except for the low LCOE.

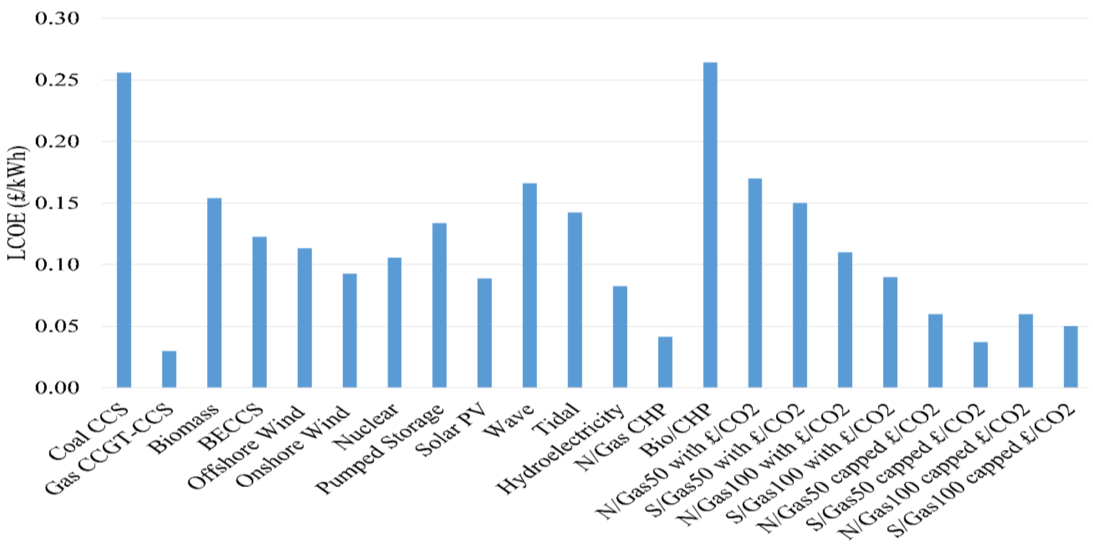

Figure 5.8. LCOE for the technologies modelled in the different scenarios.

Based on the LCOE for the technologies projected in Figure 5.8, unabated conventional and shale gas in N/Gas50, N/Gas100 and S/Gas50 scenarios with a full carbon price rank amongst the most expensive technologies, with costs reaching £0.17, £0.15 and £0.11/kWh in 2030, respectively. However, the reduced operational regime for unabated conventional and unconventional gas under the 'path to 50 and 100 g' increases the cost of generating electricity as shown in Figure 5.9. The deep cuts in emissions sought by the 'path to 50 and 100 g' decarbonisation trajectories means that the gas plants would have to operate at capacity factors below 10 % following the significant penetration of low-carbon and renewable energy technologies in the mix. In these scenarios, a total installed capacity of between 22 and 25 GW of conventional and unconventional is retained within the generation mix (see Figure 5.6) to mitigate intermittent generation. Since unabated conventional and shale gas plants are operated at 8 % and 10 % capacity factors, the cost of electricity generation with the full carbon floor price projected for 2030 is about £0.17/kWh and £0.15/kWh for N/Gas50 and S/Gas50, respectively. Also, gas plants 'in the path to 100 g' scenarios are operated at 22 % and 25 % load factors, and hence the LCOE is significantly higher in N/Gas100 compared to S/Gas100 (see Figure 5.9). The higher emission target in N/Gas200 and S/Gas200 allows gas plants to operate at 42 % and 55 % capacity factors, and thus the LCOE achieved in each scenario is £0.09/kWh (see Figure 5.9). Apart from the effect of reduced load factors, the proportion of the LCOE portrayed in Figure 5.9 for each scenario reflects on the impact of the cost of carbon. For example, the LCOE for N/Gas50 scenario is £0.11/kWh without the cost of carbon included and £0.12/kWh with the carbon floor price (CFP) capped at £18/tCO_2 in 2030.

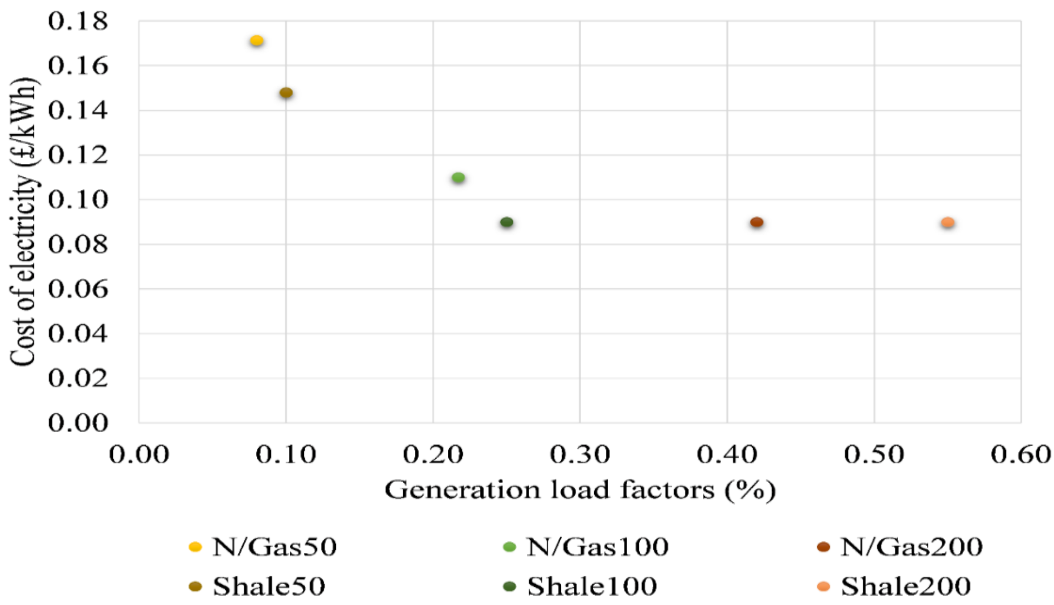

Figure 5.9. Correlation between load factor and LCOE under each decarbonisation scenario.

In the context of this electricity generation and LCOE outlay for the scenarios heavily constrained by carbon emissions, the business case for retaining a large fleet of under-performing gas plants on the system could be hard to justify given the reduced operation regime and the electricity generation cost portrayed in Figures 5.7 and 5.9. Assuming that most of the unabated gas plant capacity for the 'path to 50 and 100 g' highlighted in

Figure 5.6 is composed of a high proportion of new gas plants to ensure security of supply, the potential impact of the ‘investment lock-in’ could force utility operators to operate their plants above the operational regimes demonstrated in Figure 5.9. According to a study by Chignell and Gross (2013), the capital investment of CCGT plants are generally paid off between 10 and 20 years and during this period, utility operators would expect maximum utilisation, or ‘baseload’ operation of their plants. However, this is not compatible with the decarbonisation agenda pursued under the ‘path to 50 and 100 g’ scenarios. Since the capital financing for gas generation infrastructure is determined by the market prices for both the output and the plant load factor (Chignell & Gross, 2013), the generation outlay portrayed in Figure 5.7 and the cost of electricity generation demonstrated in Figure 5.9 would not justify the rollout and continued operation of plants within the generation mix for the ‘path to 50 and 100 g’ scenarios.

While the future of the carbon price remains uncertain, the continued role of unabated gas plants in the mix to mitigate intermittent renewable electricity supplies would need to be supported and sustained by a stronger package of economic incentives. This financing framework could give utility operators the option of either to temporarily retire or radically decrease the level of plant utilisation, especially in the context of the operation and cost regime portrayed in Figures 5.7 and 5.9. Since the introduction of the capacity markets was primarily unveiled to promote investment in new gas power plants to mitigate risk to electricity security of supply (DECC, 2014c), it is imperative that the UK government would need to come up with a package of attractive financial incentives to utility operators in order to persuade them to keep their plants on stand-by to foster both system reliability and security of electricity supply. The case for incentivising gas generation utilities becomes even stronger, particularly in the midst of a depressed market environment for gas-fired power generation spurred partly by the significantly decreased global gas prices (Caldecott and Mcdaniels, 2014).

5.2.4 The cost of decarbonising the electricity generating infrastructure

A scenario based study by Jacoby et al., (2012) warned that a shale gas “revolution” could temporarily reduce interest in low-carbon emission technologies such as CCS. In retrospect, Broderick et al., (2011) envisaged that a £32 billion investment in shale gas development has the potential to displace 12 GW and 21 GW of offshore and onshore wind capacity, respectively. In contrast, the Task Force on Shale Gas (2015) maintains that with proper policy safeguards in place, the emergence of the shale gas industry would not restrict or prohibit the ongoing development of low-carbon and renewable energy industry to meet the UK long-term energy needs. The economics of the 'path to 50, 100 and 200' decarbonisation frameworks by 2030 are illustrated in Figures 5.10 where the level of investment for low-carbon and renewable energy technologies deployed from 2015 to 2030 is outlined In order to achieve the 50 gCO_2/kWh by 2030, a £200 billion capital investment in low-carbon generation is required for the electricity sector (CCC, 2013c; Ofgem, 2010).

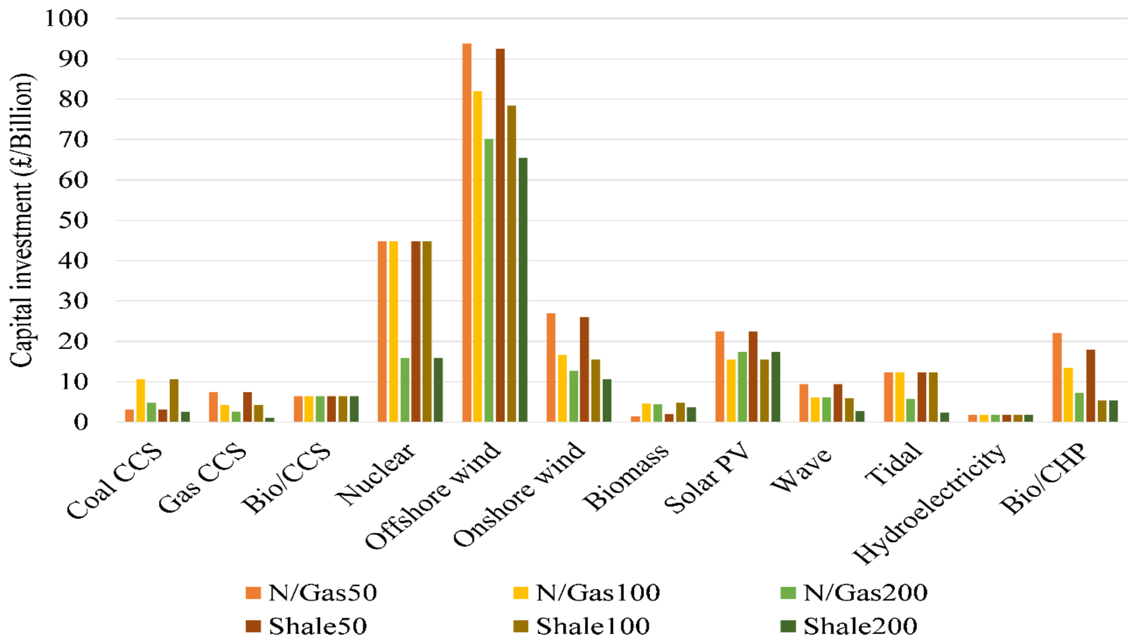

Figure 5.10. The 2015 - 2030 low-carbon and renewable energy technology investment for the decarbonisation pathways.

Large scale investment in wind and nuclear energy is respectively dominant in all scenarios with N/Gas50 and S/Gas50 recording £93.7.3 and £92.6 billion in offshore wind compared to £81.9, £78.4, £70.2 and £65.5 billion in the 'paths to 100 and 200 g' as highlighted in Figure 5.10. The large investment outlay for offshore wind is reflective of the levelised technology costs that have failed to reduce to a level below the £100/kWh threshold anticipated by the UK government by 2020, which is required to maximise its deployment in the period between 2020 and 2030 (The Crown Estate, 2012). However, there are indications that the offshore wind LCOE could come down well below the £100/MWh threshold by 2020 as demonstrated by the £114.39 clearing price achieved during the CFD Allocation Round One for the 2018/19 period (DECC, 2015b).

The investment outlay for the new nuclear power plants in the ‘path to 50 and 100 g’ scenarios is £44.7 billion compared to £15.8 billion for N/Gas200 and S/Gas200 due the differences in the estimated deployment capacities required to achieve the emissions targets set as illustrated in Figure 5.6. It is important to note that this investment outlay for nuclear power deployment depicted in the energy pathways (see Figure 5.10) is based on the capital investment for the FOAK price range. As more nuclear power plants are built, there is a potential that the investment outlay projected in the decarbonisation scenarios could come down. Onshore wind investment is high in N/Gas50 and S/Gas50, with a total of £26.9 and £25.9 billion estimated to achieve the deployment portfolio indicated in Figure 5.6. The investment in onshore wind decreases commensurate with the deployment ambitions achieved in the ‘path to 100 and 200 g’ scenarios as shown in Figures 5.10 and 5.6, respectively.

The deployment ambition for coal, gas and biomass generation fitted with CCS portrayed in Figure 5.6, could cost £3.1, £7.4 and £6.4 billion in the ‘path to 50 g’ scenarios. As the level of CCS penetration reduces with the increase in the level of emission target set, particularly in the ‘paths to 100 and 200g’, the cost requirements to deploy CCS technology are reduced as demonstrated in Figure 5.10. However, it is important to note that CCS is yet unproven at a large scale, and thus the level of deployment to 2030 is still uncertain. The investment proportion for the other technologies in all the other scenarios is shown in Figure 5.10, where the technology costs are high in scenarios seeking to achieve radical emission reduction by 2030.

The investment challenge for decarbonising the electricity supply was estimated to be £110 billion in the period to 2020 (DEEC, 2011b). The UK government envisages that between 2014 to 2020, an investment input in the order of £100 billion could be required to finance the electricity supply sector alone (DECC, 2014b). The Committee on Climate Change estimated that the low-carbon and renewable energy technology deployment for scenarios reaching 50 gCO_2/kWh by 2030 could reach up to £200 billion between 2014 and 2030 (CCC, 2013a). While there is uncertainty as to the level of renewable and low-carbon energy technology that could be deployment to achieve the decarbonisation targets set, the total investment outlay between 2015 and 2030 for the scenarios considered in this thesis is illustrated in Figure 5.11.

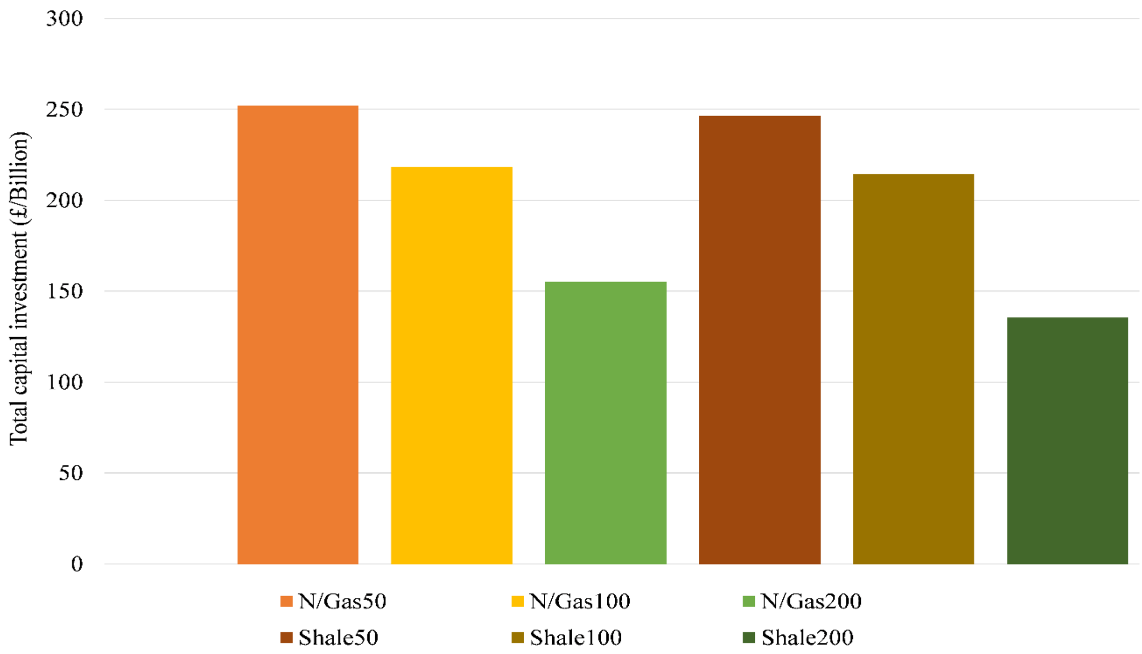

Figure 5.11. Total capital expenditure on low-carbon and renewable energy technologies in scenarios reaching 50, 100 and 200 gCO_2/kWh, both with or without conventional and unconventional gas.

The N/Gas and S/Gas50 scenarios indicate that an increased penetration in low-carbon and renewable energy technologies could respectively require an estimated investment outlay in the order of £252.1 and £246.4 billion to achieve a 50 gCO_2/kWh emission target by 2030. A policy alternative that opts for a 100 gCO_2/kWh by 2030, with or without shale gas could achieve this target with an estimated investment portfolio of £206 and £218 billion, respectively, as shown in Figure 5.11. The 'path to 200 g' has the lowest low-carbon and renewable energy resource deployment in the three decarbonisation pathways, and thus its investment outlay is £155.3 and £135.5 billion for N/Gas200 and S/Gas200, respectively. Despite the increase in the utilisation of unabated conventional and unconventional gas in 'path to 200 g' scenarios, significant contributions from wind, solar and nuclear (see Figure 5.10), assist in driving the investment portfolio to the level depicted in Figure 5.11.

The investment projection outlined in Figure 5.11 is extraordinarily high to be achieved within the fifteen year deployment timeframe. In any case, the low-carbon and renewable energy technology portfolio projected in these scenarios provide an optimised emission abatement generation mix that could assist in achieving the decarbonisation aspirations for the electricity generation sector by 2030. Therefore, it is up to the UK government, depending on the decarbonisation target they adopt for the UK electricity supply sector by 2030, to create a favourable investment climate that could trigger the flow of this enormous investment outlay required to finance the transformation of the power sector. The 2013 Energy Act introduced the EMR, a framework which is driven by the FiT CfD and the capacity market designed to deliver investment in low-carbon electricity infrastructure. These finance mechanisms, particularly the FiT CfD is designed to provide certainty to industry and investors by providing long-term price stabilisation to low-carbon electricity generation in the form of strike prices (DEECC, 2012a). Before being superseded by the FiT CfD in 2017, the Renewable Obligation (RO) (DECC, 2014b) will continue to drive investment in the development of new renewable energy generation resources. The proposed CfD strike prices for renewable energy technologies outlined in chapter 2 (see Table 2.1) provide a package of incentives designed to incentivise investment in low-carbon energy technologies required to decarbonise the electricity infrastructure as well as to guarantee security of electricity in the midst of plant closures. The arrangement for the allocation of CfD on CCS and nuclear power plants, as demonstrated by the £92.50/MWh strike price awarded to Hinkley Point C plant, over a 35 year period (DECC, 2014e) is based on bilateral negotiations between government and utility operators.

The delivery of the investment expenditure outlined in Figure 5.11 hinges not only on the enabling investment climate promoted by the EMR, but also on a concise and consistent policy delivery system which appeals to industry and the investor community. The current clamp down on green energy subsidies targeting onshore wind, and solar PV (DECC, 2015c; DECC, 2015b) could further increase the level of uncertainty over the direction and future of the energy policy, and thus undermining confidence among potential investors on the UK government's commitment to developing a low-carbon electricity sector. The new energy policy shift which seeks to build more unabated gas plants and the UK government's decision to cancel the £1 billion ring-fenced budget for CCS competition (DECC, 2015a; DECC, 2015c) could risk sending wrong signals to potential investors as to whether the government is still committed to building a low-carbon or a gas-based energy system. The decision to cancel the CCS funding could affect the future of the demonstration programmes currently running (White Rose CCS Project and Shell Peterhead Project), and thus, further increasing the uncertainty over the future inclusion of CCS technology in the UK electricity generation mix. The apparent stop-start approach which appears to characterise some aspect of the energy policy could have irreparable implications on cases for low-carbon business development, capital allocation, innovation and supply chain investment, and thus undermining the prospects for low-carbon investments (CCC, 2012) commensurate with the levels set in Figure 5.11 for the alternative decarbonisation ambitions.

5.2.5 Sensitivity analysis on low-carbon and renewable technology penetration in scenarios

The evolution of the electricity generation infrastructure to a low-carbon future is quite dynamic due to a range of uncertainties affecting the future of the electricity demand, technology innovation and the effectiveness of policy mechanisms to create a viable investment climate for the development of low-carbon and renewable energy technologies. With the electricity demand anticipated to increase between 50 and 135 % from the 2014 level by 2050 (CCC, 2015), due to the anticipated increase in the electrification of transport and heating, a 10 % increase and decrease in electricity demand has been applied to assess the potential implications of this demand variation on the low-carbon and renewable energy technology development in the 'path to 50 and 100 g' scenarios. This assessment incorporates the DECC central cost of carbon set at about £76/tCO_2e as projected for 2030 (DECC, 2013e). Also, a 10 % increase and decrease in wind and solar output has been applied on the N/Gas50 and 100 scenarios to evaluate the level of penetration of CCS technologies and nuclear power in the generation mix. A sensitivity analysis on the impact of the future of fossil fuel prices is vitally important in determining the level of fossil fuel based electricity generation and the penetration of other technologies in the electricity generation mix.

Forecasting future fossil fuel prices is challenging due to a large number of uncertainties, including future global economic growth, technology development and global climate change policies (DECC, 2015c). Assuming that a complete phase-out of unabated coal generation by 2030 in the three decarbonisation pathways, gas remains the dominant fossil fuel source of electricity generation in both unabated and CCS fitted plants. Given that the capital costs of CCGT investment are lower than most forms of generation both on an absolute basis and as a proportion of total levelised cost (Chignell & Gross, 2013), the application of any reasonable gas price variation, for example, a 10 % increase or decrease in the cost of gas would neither affect the penetration of unabated gas in the mix nor the low-carbon and renewable technologies in the mix. While all forms of CCS generation presented in this thesis are at an early stage of deployment by, 2030 (see Figure 5.6) coal plants with CCS represent one of the technologies that have the highest capital investment and LCOE (see Figure 5.8). As a key decarbonisation technology, particularly in the 'path to 50 and 100 g' scenarios, varying the cost of coal by any reasonable rate would not change its merit order within the technology cost, as it remains expensive. At the backdrop of this fossil fuel price and fossil fuel based technology cost assessment, a sensitivity analysis on the impact of fossil fuel prices on technology deployment is deemed to have little effect, particularly on scenarios seeking to achieve deep cuts in emissions by 2030. Therefore, fuel cost variation on coal CCS would only serve to increase its LCOE as well as curtail its penetration in the generation mix.

5.2.5.1 Sensitivity analysis on energy demand based on the N/Gas50 and N/Gas100 pathways by 2030

An increase in the use of electric vehicles and low-carbon heating could lead to a 50 to 135 % increase in electricity demand above the 2014 supply level (CCC, 2015) by 2050. The deployment of a combination of hybrid plug-in and battery electric vehicles across cars, vans and smaller HGVs is projected to trigger sales in the region of 60 % in 2030 (CCC, 2015), and thus increasing the demand for electricity supply. The increase in the electrification of transport and buildings could impact on the electricity generation mix, especially on scenarios seeking to promote a radical emission reduction from 2030 to 2050. The application of a 10 % increase in electricity demand in the N/Gas50 scenario results in an increase in the installed capacity of offshore wind and coal CCS by 2 and 3 GW relative to the baseline capacity, respectively. The remaining technologies are built to their maximum capacity to meet the demand as shown in Figure 5.12. Similarly, the increase in electricity demand in N/Gas100 leads to a 3.7 % increase in offshore wind capacity, 70 % coal CCS and CCGT CCS installed capacity. As in N/Gas50, the rest of the low-carbon and renewable energy technologies assessed retains the maximum installed capacity of the baseline mix as shown in Figure 5.13. The results from this sensitivity assessment have important policy implications as they underscore the need for a flexible policy framework that creates an enabling environment for the development and deployment of low-carbon and renewable energy technologies which achieve both energy security and climate change objectives. While the future deployment rates for low-carbon technologies remain uncertain, a surge in the rate of deployment of low-carbon technologies following an increase in demand could provide insights to policymakers on how to develop strategic policy frameworks that ameliorate barriers that hinders progress in the deployment of emission reduction technologies.

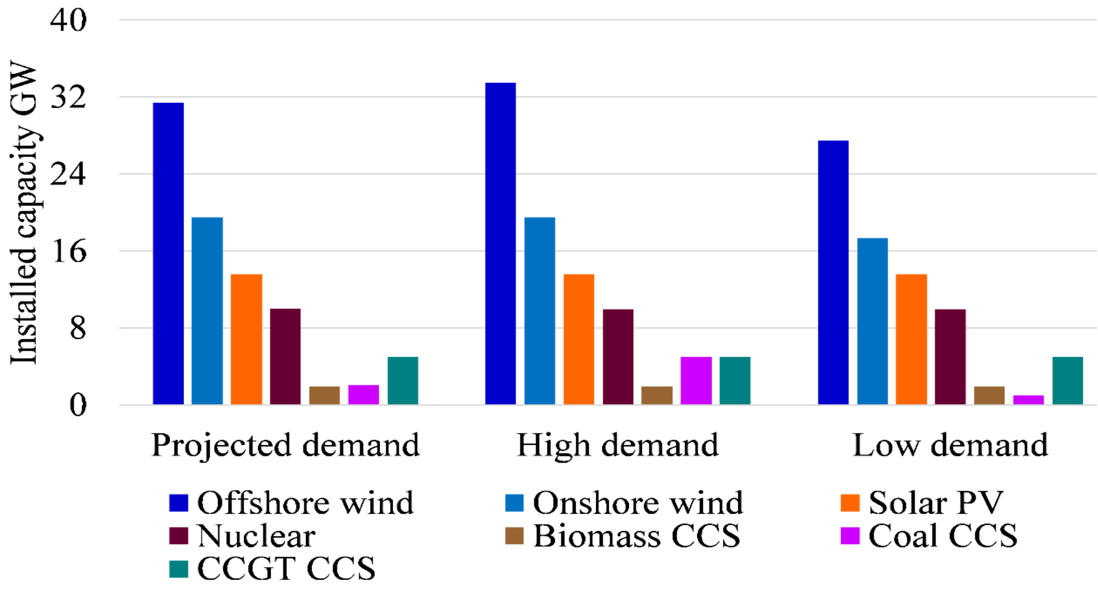

Figure 5.12. The impact of varying electricity demand on low-carbon and renewable technology uptake in N/Gas50 scenario.

Delays in the electrification of transport and buildings, coupled with significant improvements in energy efficiency measures could culminate in electricity demand reduction by 2030. On the same note, a slump in economic growth can also account for the decline in the demand for energy. Applying these dynamic factors to the electricity supply landscape by 2030, the impact of a 10 % electricity demand reduction on the N/Gas50 scenario could result in a reduction in the uptake of offshore, onshore and coal CCS. Offshore wind capacity is reduced by 3.9 GW while onshore experiences a 2.2 GW decline compared to the baseline scenario as shown in Figure 5.12. The high LCOE (£0.26/kWh) for coal CCS accounts for the 50 % reduction in capacity following the 10 % fall in demand. The other technologies (nuclear, solar and CCGT CCS) retain their baseline capacity since they have the least LCOE (see Figure 5.8) within the low-carbon and renewable energy technologies being assessed. The impact of a 10 % electricity demand reduction on the N/Gas100 scenario has a similar effect as that in the N/Gas50 scenario. The penetration of offshore and onshore wind, as well as coal CCS is reduced by an average of 28 %, relative to the baseline mix. Although the low-carbon and renewable energy technology development is reduced by a small margin following a decline in demand, the policy plan and momentum would need to remain focused on achieving maximum deployment targets to achieve a sectoral transition to a low-carbon economy.

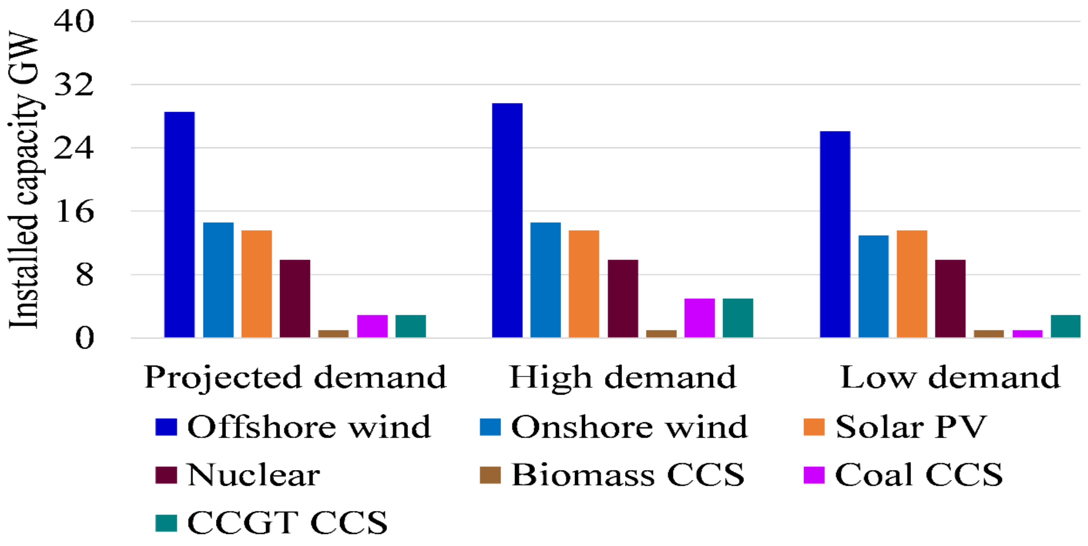

Figure 5.13. The impact of varying electricity demand on low-carbon and renewable technology uptake in N/Gas100 scenario.

5.2.5.2 Sensitivity analysis: varying wind and solar PV output on low-carbon technologies in N/Gas50 and N/Gas100 pathways by 2030

The decarbonisation of the electricity generation sector by 2030 would require an estimated 40-70 GW of low-carbon and renewable energy technology rollout through the 2020s (HM Government, 2011). A 10 % increase in electricity generation from wind and solar PV in the N/Gas50 scenario would result in a drop in capacity on technologies with higher LCOE. Under this scenario, coal CCS deployment falls from 1.9 to 1 GW whilst the rest of the other low-carbon energy technologies retain their baseline capacity as shown in Figure 5.14. The impact of increasing wind and solar energy output on the N/Gas100 scenario affects the rollout of coal and gas CCS plants. The growth in coal CCS is reduced by 1.8 GW, a 61 % drop from the baseline capacity outlay of 2.9 GW, as depicted in Figure 5.15. The development of a least-cost generation mix ensures that more gas CCS at £0.03/kWh is built in place of the high cost coal CCS. As a result, gas CCS increases by 2.1 GW following the constrained build-up of coal CCS. Nuclear power LCOE is £0.11/kWh and based on this generation cost, a maximum deployment outlay of 9.9 GW is achieved following the increased output from wind and solar PV. On the other hand, at a high LCOE of £0.12/kWh, biomass CCS rollout is limited to a minimum capacity of 1 GW contribution to the low-carbon mix as highlighted in Figure 5.15. The high penetration of variable generation sources in the mix has huge implications on security of electricity resulting from variable weather patterns. Therefore, the increased investment in gas plants fitted with CCS could provide a cost effective approach to mitigate the challenges of intermittent generation from wind and solar.

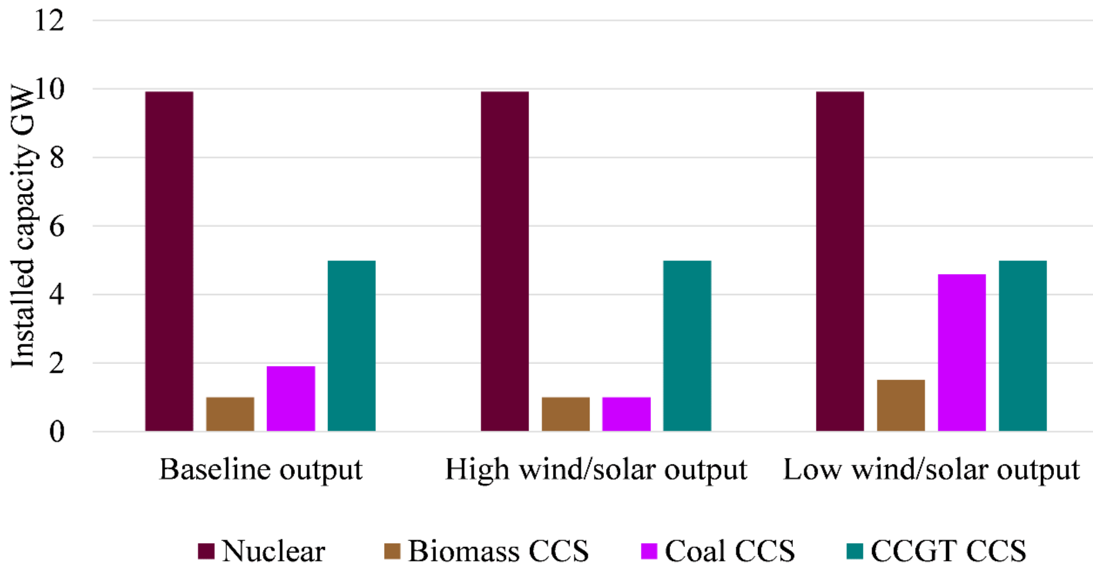

Figure 5.14. The impact of varying wind and solar output on low-carbon technologies in the N/Gas50 scenario by 2030.

The availability of wind and solar power resources as determined by the variability in weather patterns has huge implications on the reliability of electricity production within the electricity generation system. Decreasing the wind and solar energy output by 10% results in all low-carbon energy technologies achieving the maximum deployment potential in the N/Gas50 scenario. While nuclear power and gas CCS retrofitted plants respectively retain their baseline maximum capacity of 9.9 and 4.9 GW, the deployment of coal and biomass CCS plants increase by 2.7 and 0.5 GW following the drop in wind and solar energy output, as highlighted in Figure 5.14. A similar drop in wind and solar energy output in N/Gas100 scenario results in a 2.1 GW capacity increase in coal and gas CCS power plants. Nuclear power deployment is retained at a maximum baseline capacity of 9.9 GW while the high LCOE for biomass CCS constrains its deployment to the generation mix to a minimum capacity of just 1 GW as indicated in Figure 5.15. The results from this assessment underscore the value of nuclear power and CCS applications in the decarbonisation framework of the UK energy policy. In the context of these results, government policy would need to foster diversity in the development of low-carbon and renewable energy technologies in order to breed competition that could assist in driving innovation and cost reductions (HM Government, 2011).

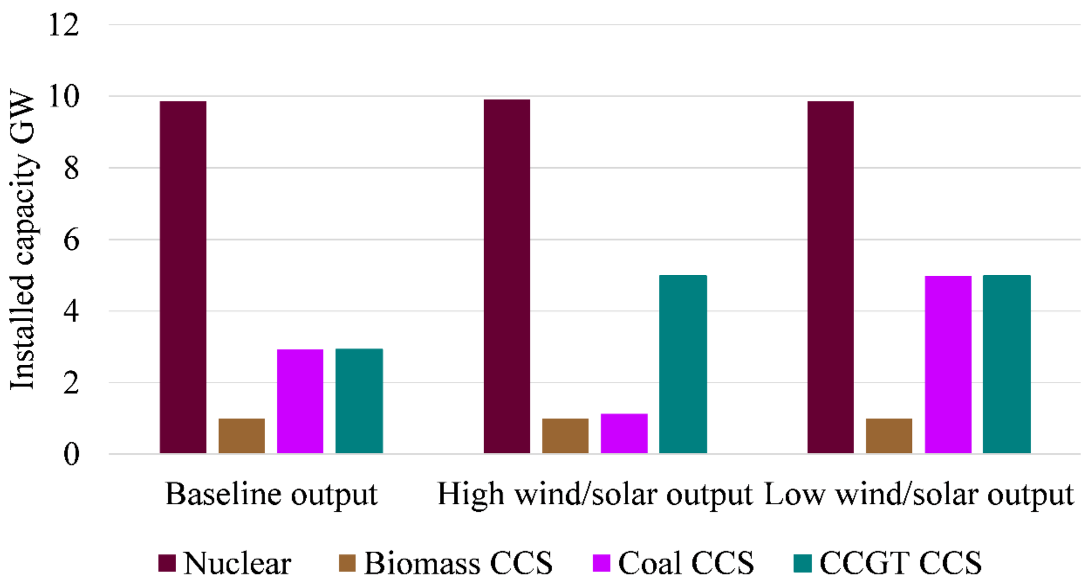

Figure 5.15. The impact of varying wind and solar output on low-carbon technologies in N/Gas100 scenario

5.2.5.3 Sensitivity analysis: varying gas and carbon price by 10 % and the impact on gas output in N/Gas50 and N/Gas100 pathways by 2030

Kaufmann (1994) observed that there is considerable uncertainty associated with the effect of the expected energy prices on energy demand. The price of primary energy is one of the most important indicators which is used to determine its demand and the level of utilisation in various energy transformation processes. Also, energy prices are affected by carbon taxes imposed on unabated fossil fuel electricity generation processes. Sensitivity assessments have been performed to assess the impact of varying the cost of fossil fuel (gas) and carbon tax by 10 % on unabated gas generation in the N/Gas50 and N/Gas100 scenarios by 2030. The sensitivity assessments on gas plants fitted with CCS technology only apply a 10 % fuel variation as they are exempt from the carbon floor price (DECC, 2012a). The same analysis has not been extended to cover the 200 gCO_2/kWh pathway due to its higher decarbonisation target which ultimately favours unabated fossil fuel powered generation to low-carbon and renewable energy sources.

Increasing the cost of gas and carbon on these decarbonisation scenarios neither increases nor decreases the penetration of unabated gas plants in the generation mix nor the electricity generated. The deep cuts in emissions projected by the ‘path to 50 g’ scenario constrains the uptake of gas CCGT to 24.1 GW with a 16.7 TWh generation output when the cost of gas and carbon is increased or decreased by 10 %. The adoption of a 100 gCO_2/kWh decarbonisation target allows a total of 24.9 GW capacity of unabated gas in the mix to contribute 46.9 TWh to the total electricity demand by 2030. This deployment and generation profile is replicated in this scenario when the cost of gas and carbon is increased or decreased by 10 %. The penetration and utilisation of generation plants using gas fuel remains unchanged in both the N/Gas50 and 100 scenarios compared to the baseline scenarios. This is due to the structural function of the model which sets a minimum capacity within the total gas installed capacity as a safety net designed to safeguard against energy capacity inadequacies. Another potential reason why the level of gas capacity remain unchanged after variations in demand or carbon cost is probably due to the build-up rate set in the model which determines the level of unabated gas capacity in the generation mix. These issues were discussed in detail in Section 3.3.9. The only change that emerges from a sensitivity assessment involving gas and carbon price variations on gas plants is that of the cost of electricity generation, as highlighted in Figure 5.16.

The cost of electricity generation in the N/Gas50 baseline scenario is £0.17/kWh compared to £0.18 and £0.16/kWh following a 10 % increase and decrease in the combined cost of gas and carbon emissions, respectively. On the other hand, the N/Gas100 baseline scenario's LCOE is about £0.11/kWh, but the cost of electricity generation respectively increases and decreases to £0.12/kWh and £0.1/kWh following a 10 % increase and decrease in the cost of gas and the carbon floor price as shown in Figure 5.16. The difference in the LCOE demonstrated in the N/Gas50 and N/Gas100 baseline scenarios is influenced by the higher load factor, the increased installed capacity and generation output as described in Figure 5.9 (see Section 5.2.3). In all the scenarios, the LCOE from gas plants fitted with CCS remain unaffected by the price variations on both gas and carbon as depicted in Figure 5.16, where the LCOE is maintained at £0.03/kWh.

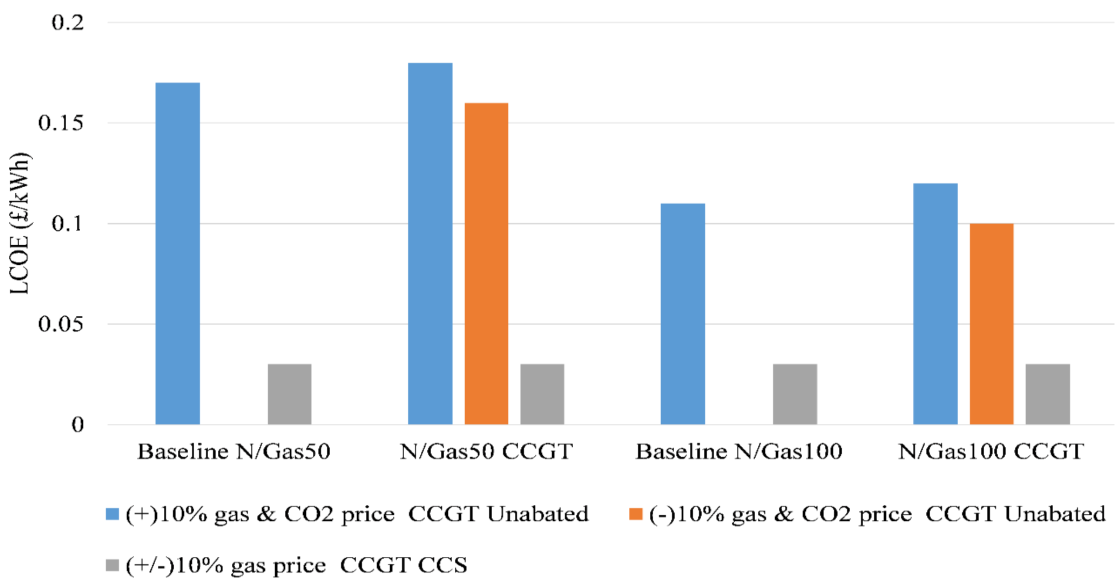

Figure 5.16. The impact of a 10 % variation of gas and carbon price on the LCOE of unabated gas and gas CCS.

5.2.6 Summary

The UK shale gas development is still at exploration stage. Its use in the electricity generation sector is anticipated in the late 2020s. However, the decarbonisation framework presented by the 'path to 50 and 100 g' pathways limits the use of conventional and unconventional gas in the generation mix by 2030. Unabated gas plants under the 'path to 50 and 100 g' scenarios are operated at capacity factors below 10%, mainly as back-up up to increased intermittent generation resources within the electricity supply system. Based on this limited operational regime of unabated gas plants in the 50 and 100 gCO_2/kWh decarbonisation targets by 2030, the introduction of shale gas in the generation mix may not alter the low-carbon and renewable energy technology development and deployment framework required to cut carbon emissions.

The benefits of shale gas in the electricity generation could be realised under large decarbonisation targets such as the 'path to 200 g' where unabated gas plants are operated at 55 % capacity factor. At a baseload operational regime of 55 %, the unabated shale gas generates 142.8 TWh, and thus limiting the penetration of low-carbon and renewable energy technologies to 7.3 and 56.6 GW by 2030 compared to 17 and 84.8 GW in S/Gas50 in the same period. The scale of low-carbon and renewable energy technology investment under the 200 gCO_2/kWh decarbonisation is £135.5 billion compared to £246.4 and £206 billion in S/Gas50 and S/Gas100, respectively. The reduced capital investment likely to be achieved through the increased use of shale gas in electricity generation under the 'path to 200 g' could come at the expense of the UK 2050 emission reduction target as well as the pledge to limit global annual GHG emissions agreed at the Paris COP21 (UNFCCC, 2015).

Chapter 6 Mitigating the challenge of intermittent energy resources

6.1 Introduction

The Climate Change Act set a legally binding carbon emission reduction target of 80 % by 2050 against the 1990 level to be achieved by the UK economy (HM Government, 2008). The transition of the UK economy to a low-carbon future by 2050 is highly dependent on the rate at which the electricity generation sector is decarbonised. A cost-effective transition to the 2050 emission reduction target implies that the electricity generation sector would have to achieve a 100 gCO_2/kWh decarbonisation target by 2030 in order to meet the fifth carbon budget requirements (CCC, 2015). The positioning of the electricity generation sector on the path to a low-carbon future would require the deployment of low-carbon and renewable energy technologies at unprecedented levels. While the UK energy policy seeks to promote a diverse share of low-carbon energy technologies in its quest to decarbonise the electricity supply sector by 2030, offshore wind is anticipated to be one of the key drivers of this campaign. The prioritisation of offshore wind as one of the catalysts for cleaning up the electricity supply sector stems from the understanding that the UK has an excellent offshore wind resource (Boston Consulting Group, 2010) as well as the fact that the technology is not polarised to public attitudes compared to onshore wind farms.

However, the energy generated from renewable energy technologies is intermittent in nature, meaning that their output is determined by weather conditions, in contrast to “dispatchable” generators that adjust output as a reaction to economic incentives (Hirth, 2013). As for wind energy, the projected or predicted power output is a product of an interplay of a set of parameters such as wind speed and direction, air density as well as spatial/temporal scales of atmospheric motion (Rahimi et al., 2013). In the context of the technology’s higher dependency on weather conditions, a high penetration of variable wind and solar energy resources have profound implications on the operation of the electricity generation and grid systems. High volumes of intermittent wind and solar in the generation mix have a huge impact on the operation regime of the flexible fossil-fuel plants which would have to be shut down and restarted, ramped up and down, and operated at part-load (Lew et al., 2013) to deal with the effects of variable electricity output on the delivery of reliable electricity production systems.

The configuration of the electricity generation system owing to an increased penetration of intermittent wind and solar energy has a potential to increase costs and emissions. The displacement of fossil-fuel generation from the system during high wind periods could impact on the economics of flexible generation from a utility owner's perspective. A study by BENTEK Energy (2010) suggests that the emissions induced by the ramping up and down of flexible generation plants, as a result of the variability and uncertainty of wind and solar energy output, could amount to a significant fraction or even larger than the emission reduced by wind and solar.

The impact of the carbon emissions resulting from the variable operation of fossil-fuelled generation plants in response to the renewable energy sources on the system could be negligible, however, concern over operation costs and the challenge of delivering reliable and low-carbon electricity supplies is unavoidable to both utility owners and policymakers. Since the development of a renewable electricity generation system is at the heart of the UK decarbonisation agenda, it is imperative that a balanced policy approach is adopted to mitigate any challenges created by an influx of intermittent generation energy sources in the generation mix. A two-prong approach is adopted in this chapter to discuss the issue of intermittent renewable energy resources and its implications on the electricity generation system.

The first section explores how the model deals with the issue of intermittency in its current state while the second section characterises the concept of wind power variability based on analysed wind data. The projected offshore wind power and energy output for the scenario achieving a 100 gCO_2/kWh grid intensity by 2030 is examined based on the meteorological and geographical attributes of the sites from which most of the 2030 projected capacity is expected to be sourced as well as on the wind turbine model specifications selected for this assessment. The wind resource variability on offshore wind determined from site wind data analysis is used to assess the overall contribution of wind energy against the benchmarked 2030 scenario outlook set by the model in its original state. After assessing the potential impact of intermittent energy output from offshore wind on the electricity sector decarbonisation by 2030, the section concludes by outlining the model modifications that could be adopted in order to integrate the impact of intermittency in its optimal calculations.

6.2 Conceptualising intermittent/variable electricity generation sources

The concept of variability or intermittency in renewable energy technology analysis is vitally important in understanding energy system costs as well as strategies for renewable energy development. Intermittent electricity generation affects electricity supply operation through system balancing and reliability impacts. The balancing impacts refers to the rapid short-term configurations required to manage fluctuations over a time period while the reliability influences relate to the measure of confidence that can be ascribed to the electricity supply system that sufficient generation could be made available to supply peak demand (Gross et al., 2006). The dynamics affecting electricity output from renewable energy resources can be determined based on diverse characteristics which range from statistical distribution, persistence, frequency or correlations (Coker et al., 2013). As with wind and solar energy, the concept of variability tends to focus on the statistical analysis of the wind and solar resource and its implications on the entire energy supply system. The creation and maintenance of a reserve capacity, which has been described in Gross et al. (2006) as “standby capacity”, “back-up capacity” or “system reserves” in the form of flexible fossil-fuelled generation could provide the level of reliability to guard against the potential risk of demand being unmet.

The variability of the offshore wind energy resource challenge presented in this thesis is investigated through a statistical distribution approach, which focuses on the variance of intermittent output; the average level of intermittent output and the degree of correlation between demand peaks and intermittent out (Gross et al., 2006). It is through this analysis that the operation regime of stand-by thermal plants is evaluated to determine the extent to which the ‘demand net wind’ resulting from the intermittent generation is mitigated in a way that maintains system reliability and energy security standards. Also linked to the statistical analysis of energy outputs from different energy sources is the capacity factor, a measure of the total energy generated across a period of time to the maximum designed power output of an installation (Coker et al., 2013). The characterisation of variability of renewable energy sources using statistical analysis provides the means by which unabated fossil-fired and renewable energy supply systems can be integrated in low-carbon transition futures.

6.2.1 Dealing with variability: The 'Energy Optimisation Calculator'

The EOC is designed to assemble a least-cost and polluting electricity generation mix based on predetermined input parameters. The low-carbon transition narrative projected by the model implies that a diverse mix of electricity generation technologies is integrated in the model to assemble a supply portfolio that achieves radical emission reductions while maintaining security of energy supply over the transition period. With a huge proportion of variable renewable energy resources deployed in the mix for the majority of the low-carbon pathways, the model calculator, in its original state does not characterise the issue of intermittence in a manner described in Section 6.2. In the context of the 2030 scenario which achieves a 100 g/kWh carbon grid intensity, the model assumes that a 31.3 GW total installed capacity of offshore wind would generate electricity at a constant capacity factor of 29.4 % as depicted in Figure 6.1. Similarly, on an 11.3 GW installed capacity of onshore wind, the model assumes a persistent annual electricity generation pattern in the order of 19 % capacity factor as shown in Figure 6.1. However, with the intermittent nature of many types of renewable energy technologies, it is evident that the model does not adequately reflect the impacts of intermittent generation on the UK electricity supply system.

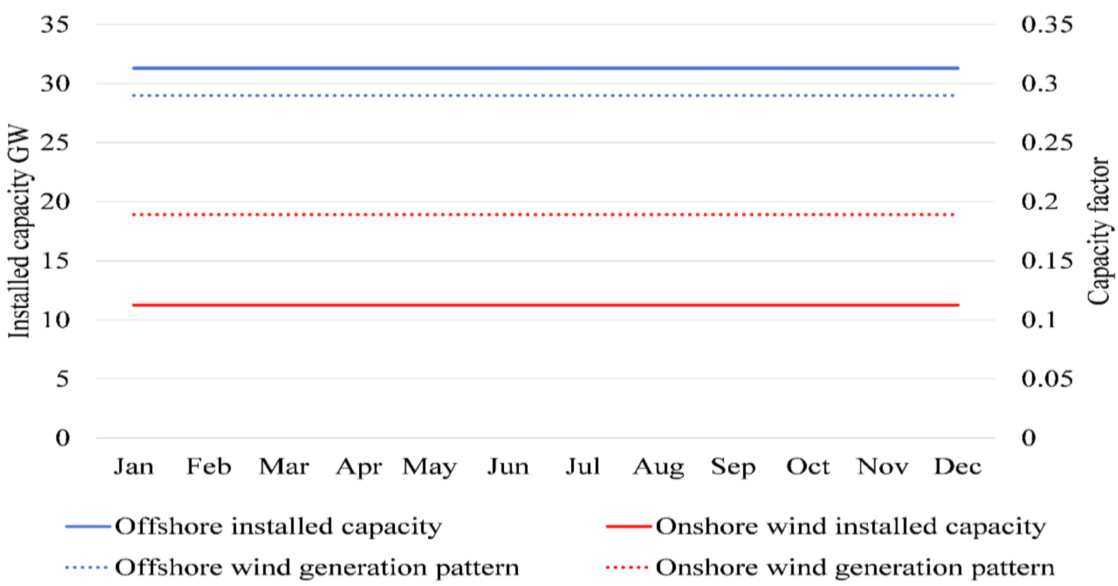

Figure 6.1. The assumed model approach in determining electricity generation from offshore wind based on the deployment capacity in the 'path to 100g' scenario.

The optimisation function of the energy calculator can either follow a least-cost or emission abatement path depending on the objectives of the energy analysis. In either of the optimisation cases, the model can still provide an optimal output that reflects either the financial or sustainability credentials of the energy mix desired. The issue of intermittency is probably not a major issue in a scenario which seeks to develop a least-cost generation mix as shown in Figure 6.2. A least-cost generation mix has a respectively high unabated CCGT plant and interconnector capacity of 30 and 8 GW as shown in Figure 6.2 compared to renewable energy technologies. In that respect, the challenge of intermittency to renewable energy sources would not pose any threat to the system reliability, even in a case where the model was treating variability based on statistical factors. Given an 80 % plant utilisation/availability factor coupled with a baseload running regime of 45 %, a 30 GW capacity of gas CCGT has enough scope to address any potential supply deficits likely to be induced by the variable renewable energy resources. While an optimal cost electricity supply mix developed has a high potential to achieve security of supply objectives, its sustainability credentials are not compatible with the prevailing low-carbon agenda seeking to decarbonise electricity supply infrastructure.

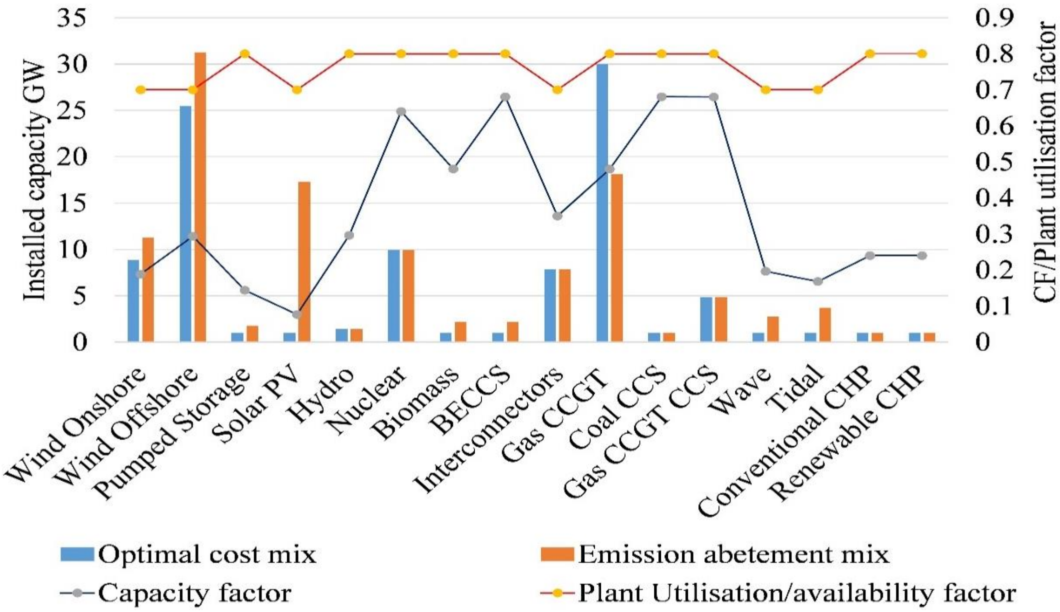

Figure 6.2. The 2030 'path to 100 g' scenario and the technology mix developed based on the optimal cost and emission abatement approach.

The development of a low-carbon energy technology mix that meets the 100 gCO_2/kWh emission target by 2030 as shown by the emission abatement mix in Figure 6.2 would require a policy framework that has the fortitude to breakthrough technical, economic and social barriers. Ideally, the high penetration of onshore and offshore wind and solar PV in the order of 16, 31.3 and 17 GW respectively, could have profound implications on system reliability and security of supply, especially where flexible generation capacity (CCGT plant) is substantially constrained. However, since the model apportions capacity to renewable energy technologies sources with no due regard to variability, the issues of reliability and security of supply become irrelevant in this scenario. This is because the contribution from offshore wind to the electricity demand (80.6 TWh) is sufficiently high to promote system adequacy. This level of energy output from offshore wind is assumed to be supplied constantly throughout the year without any fluctuations associated with wind resource variability. Thus, it is important to note that the contribution from offshore wind to total energy supply does not reflect the impact of variability in the final energy output as exhibited in energy scenario outputs.

The levelised cost of electricity indicator for the optimal cost and emission abatement scenarios is £0.07 and £0.1/kWh respectively, based on the model calculations. While the cost of electricity output favours the optimal cost over the emission abatement scenario, the emission performance of the two scenarios, particularly the least-cost mix presented in Figure 6.3 suggests a worrying outcome to the policy objective of creating a low-carbon electricity supply future. The optimal cost mix has a cumulative emission outlay of 63 $MtCO_2e$ based on the ‘path to 100 g’ technology mix. This emission performance of this fossil fuel dominated least-cost generation mix has a grid carbon intensity of 183 g/kWh. On the other hand, the high penetration of low-carbon and renewable electricity generation technologies such as nuclear, fossil fuel fitted with CCS, wind and solar in the abatement technology mix reduces cumulative emissions by 45 % compared to the optimal cost mix to achieve a reduction capacity of 34.4 $MtCO_2e$ at a 100 gCO_2/kWh grid intensity.

It is important to note that such a drastic emission reduction would incur a cost penalty as demonstrated by the difference in the cost of electricity between the two energy generation mix scenarios. The electricity generation mix and the associated emission output characterised in Figures 6.2 and 6.3 as presented by the model in its original state, could be used to provide a guide to the technology mix that could be developed to meet energy policy objectives with regard to electricity sector transition. In order to shed more insight into the technical, economic and planning dynamics affecting each of the technologies and their implications on the development of low-carbon energy futures, the analysis approach similar to that adopted in the following sections is vitally important in enhancing the credibility of the modelling framework for future energy pathways.

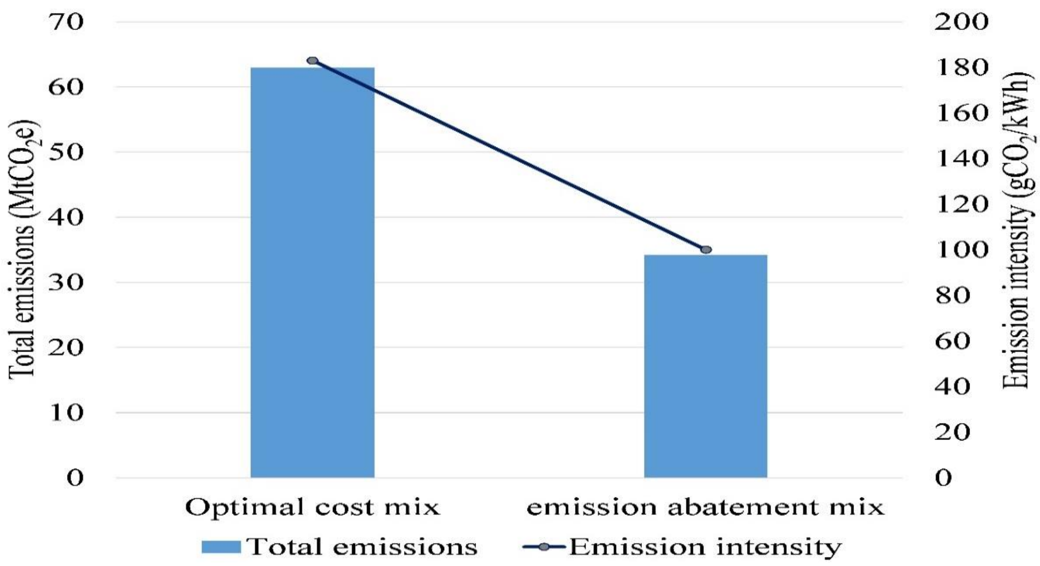

Figure 6.3. The comparison of the emission performance of the cost and emission optimisation generation mixes based on the 'path to 100 g' decarbonisation scenario by 2030.

6.2.2 Offshore wind energy: wind data analysis

The offshore wind energy resource, which is central to this thesis has been analysed and evaluated using calculated Weibull density function shape k and scale c parameters summarised in Table 6.1 based on wind speed data measured at 50 and 80 m height. The shape k parameter represents the width/peak of the wind speed distribution at any given geographical location while the scale factor c describes how windy the location is (Shu et al., 2015). As noted in Section 3.3.7.1, these parameters provide a quantitative assessment of the available wind resource and the potential electrical power output likely to be converted by a wind turbine at any given site. The Weibull shape and scale (k and c) parameters highlighted in Table 6.1 are used to determine the wind power density, a measure of the energetic nature of winds at any given place and time (Shu et al., 2015). Shape k values at 50 and 80 m height shown in Table 6.1 appears to be similar which could suggest that the variability of the wind at the assessed heights could be construed to be the same. The dimension of the scale parameters given in Table 6.1 are dependent on both the shape parameter and the observed wind speed which invariably is influenced by the quality of the wind at the assessed heights.

Table 6.1. Calculated Weibull density function parameters for characterising the wind resource at different UK offshore wind development zones.

Weather stations	Offshore wind site	Shape (k)		Scale (c)	
		50 m	80 m	50 m	80 m
Boulmer	Dogger Bank	2.18	2.181	9.94	9.949
Bridlington	Hornsea	2.237	2.237	8.868	9.358
Dunbar	Firth of Forth	2.216	2.216	8.695	9.175
Hemsby	Norfolk	2.218	2.218	9.34	9.855
Mumbles Head	Bristol Channel	2.37	2.376	8.25	8.254
Ronaldsway	Irish Sea	2.109	2.109	9.082	9.584
Shoreham Airport	Hastings	2.353	2.353	8.055	8.499
Swanage	West of Isle of Wight	2.14	2.144	9.75	9.757
Wick Airport	Moray Firth	2.358	2.358	9.536	10.063

The Weibull density function parameters shown in Table 6.1 have been used to characterise the nature of the wind resource at the nine offshore wind sites at different hub heights, in terms of the wind speed frequency and the probability of occurance. The frequency and strength of the wind resource for each site is illustrated in Figures 6.4 to 6.21. It is evident from Figures 6.4 to 6.21 that the wind speeds show a high degree of variation, and they are unevenly distributed at each of the sites assessed. Within this spectrum of fluctuating and unevenly distributed wind speeds, it is worth noting that most of the time there are weak winds with occassional strong winds which could impact on the dynamics of wind turbines, and hence the variations in the potential site power/energy output. Nonetheless, the frequency of the wind resource portrayed on the selected offshore wind sites (see Figures 6.4 to 6.21) indicates a wider threshold between the cut-in speed and the cut-out speed at which the operability and productivity of the wind turbines is ascertained. Furthermore, most of the assessed offsshore wind sites have a high probable (most frequent) wind speed of about 8 m/s which has a greater potential to increase the wind turbine capacity to capture the maximum power in the wind.

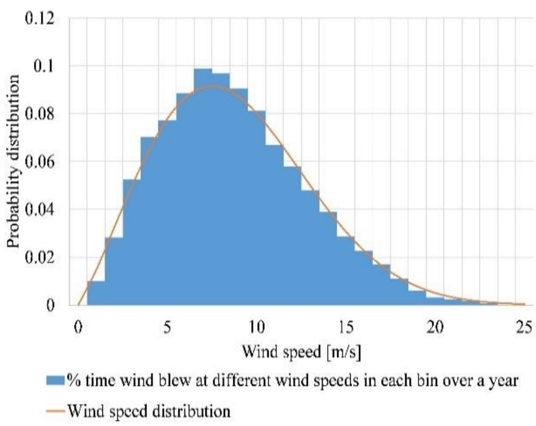

Figure 6.4. Boulmer wind resource at 50m.

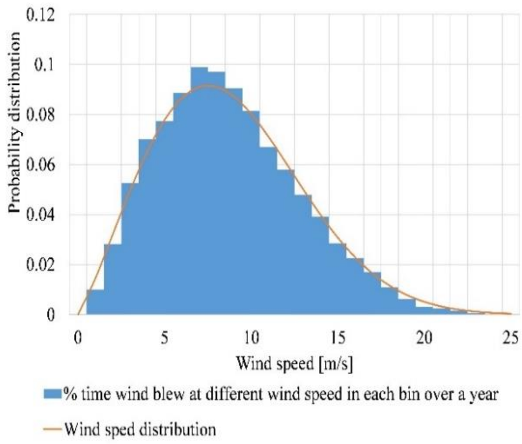

Figure 6.5. Boulmer wind resource at 80m.

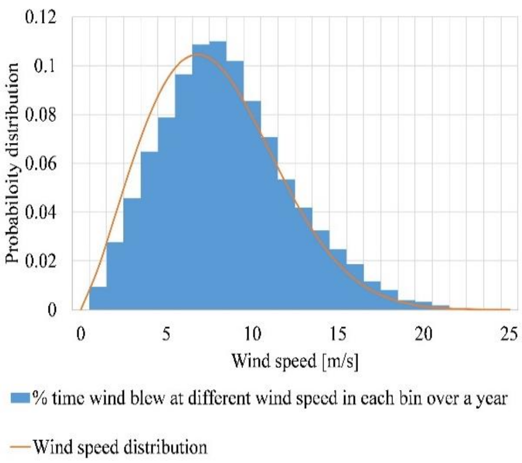

Figure 6.6. Bridlington wind resource at 50m.

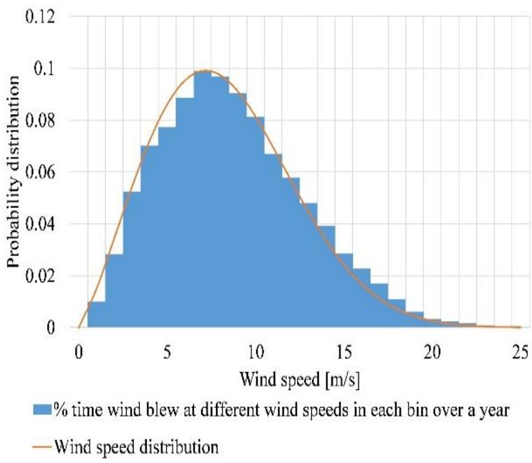

Figure 6.7. Bridlington wind resource at 80m.

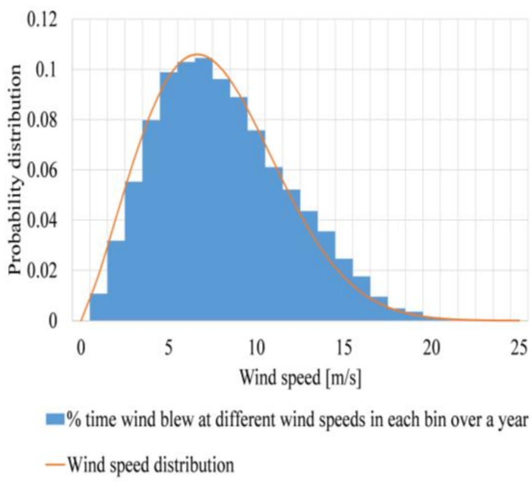

Figure 6.8. Dunbar wind resource at 50m.

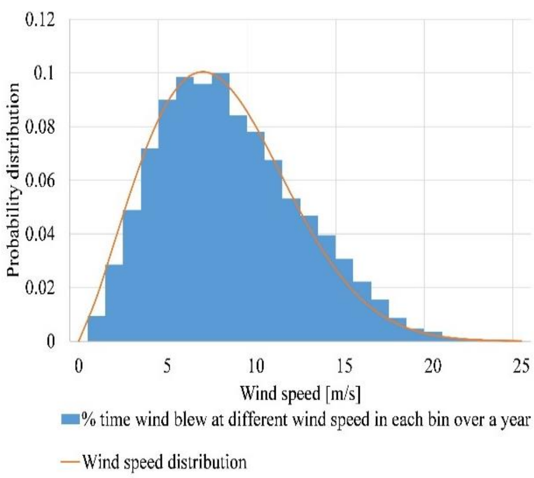

Figure 6.9. Dunbar wind resource at 80m.

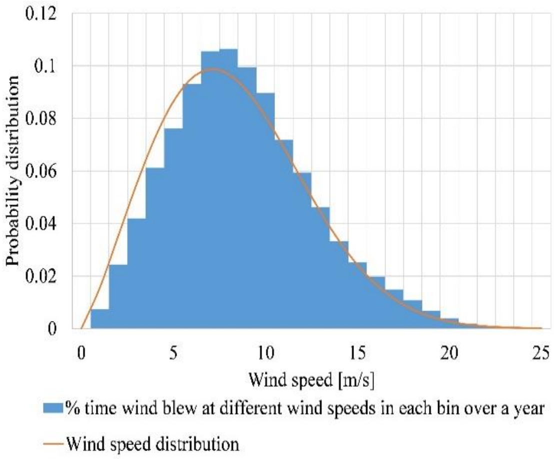

Figure 6.10. Hemsby wind resource at 50 m.

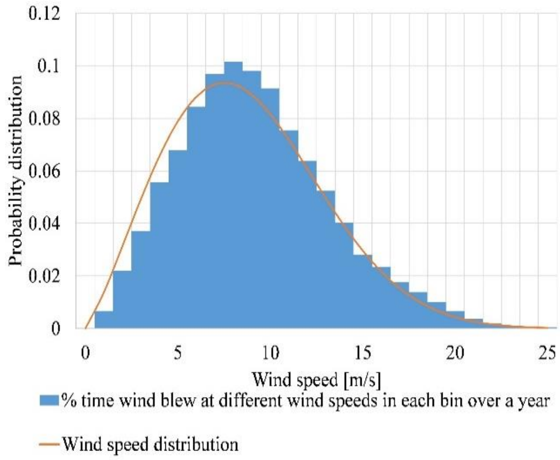

Figure 6.11. Hemsby wind resource at 80 m.

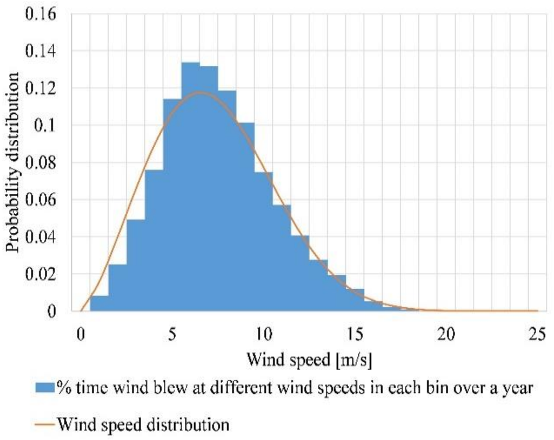

Figure 6.12. Mumbles Head wind resource at 50 m.

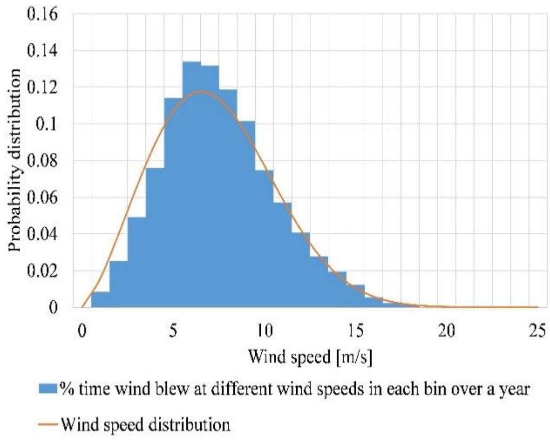

Figure 6.13. Mumbles Head wind resource at 80 m.

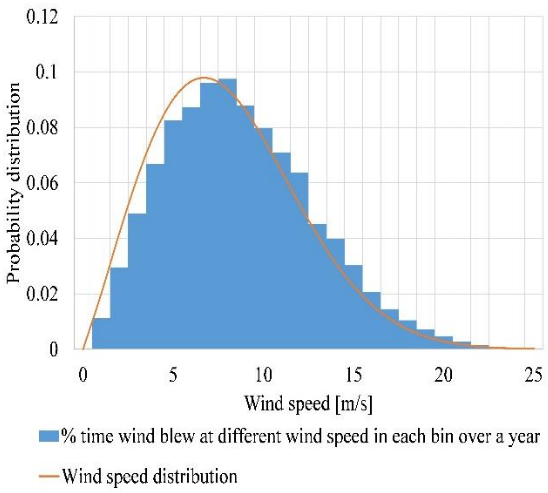

Figure 6.14. Ronaldsway wind resource at 50 m.

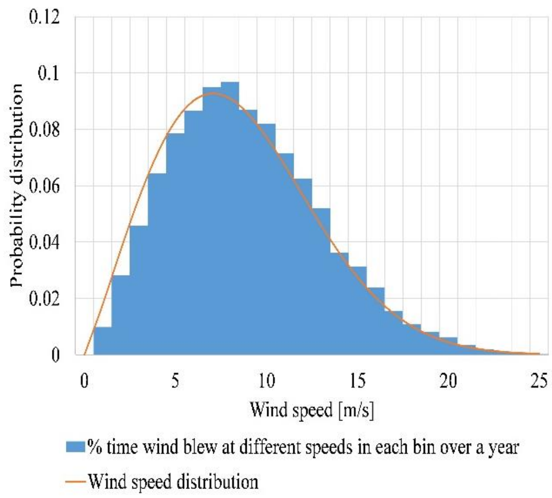

Figure 6.15. Ronaldsway wind resource at 80 m.

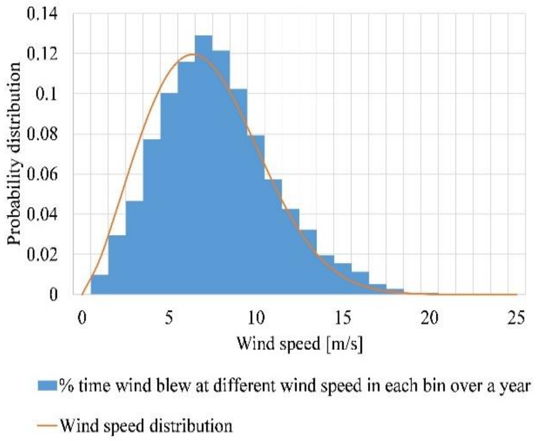

Figure 6.16. Shoreham Airport wind resource at 50m.

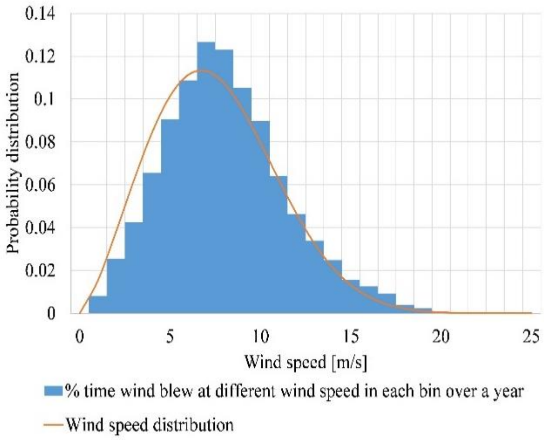

Figure 6.17. Shoreham Airport wind resource at 80m.

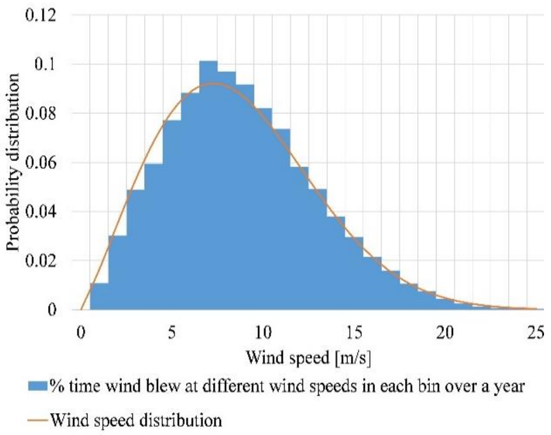

Figure 6.18. Swanage wind resource at 50m.

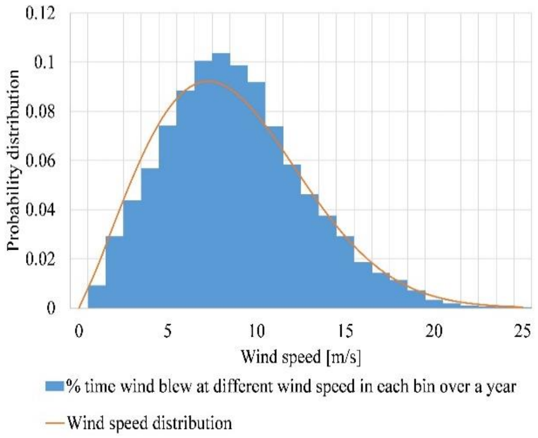

Figure 6.19. Swanage wind resource at 80m.

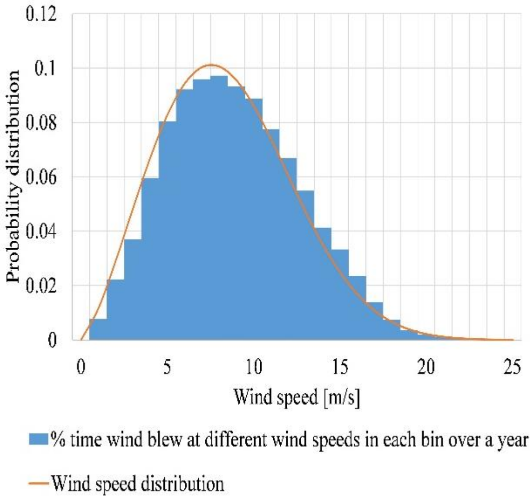

Figure 6.20. Wick Airport wind resource at 50m.

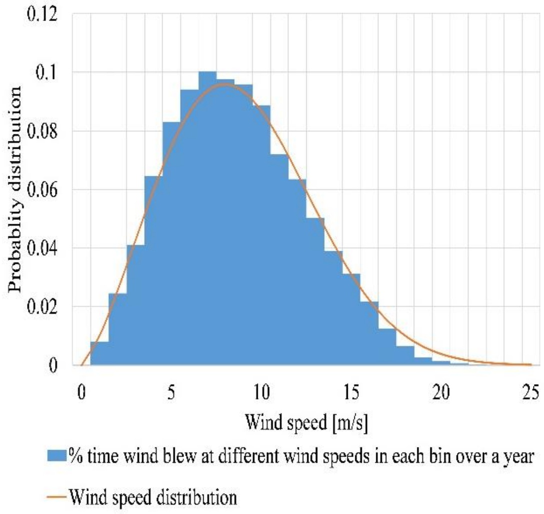

Figure 6.21. Wick Airport wind resource at 80m.

The high wind distribution frequency observed from the analysed data in Figures 6.4 to 6.21 ranges between 4 m/s to 25 m/s threshold which forms an important measure of the potential power likely to be yielded at the wind farm site observed. On the basis of the wind speed distribution and the wind power density of each site portrayed in Figures 6.4 to 6.21, the potential power output of the 8 MW and 10 MW power rated wind turbines installed at different heights at each offshore wind farm site is determined. The interaction between the mean annual wind speed and wind density distribution shown in Figures 6.4 to 6.21 and the turbine power characteristics is used in the analysis of the electrical power and energy output from the offshore wind farm sites considered in this thesis. The power/energy output of the wind turbines selected (8 and 10 MW) is calculated by integrating the cut-in and the cut-out speeds of the turbine within the wind probability function and the characteristics of the turbine power curve (Olaofe & Folly, 2013). In the context of the wind power/energy analysis carried out in this thesis, the cut-in and cut-out wind speed ranged between 4m/s and 25m/s with variations observed from site to site.

The wind power resource potential exhibited in Figures 6.4 to 6.21 provides an important economic and policy tool for assessing the development and integration of wind energy technology into the UK electricity supply system. The temporal and spatial variations in the annual wind speed has a direct influence on the wind energy density variations, which in turn provides a measure of the potential power/energy yield from wind farm developments. The assessed wind energy resource demonstrated in Figures 6.4 to 6.21 for the proposed offshore wind sites is projected to contribute towards the 2030 capacity (31.3 GW) for the 'path to 100 g' scenario. The impact of variability is of great significance in the context of the policy ambition to achieve a 100 g/kWh carbon grid intensity for the electricity sector by 2030 (CCC, 2015). The magnitude of the wind resource variability as determined by the assessments in Figures 6.4 to 6.21 is important in determining the aggregated power from offshore wind farm sites against the optimised offshore power capacity projected by the model without accounting for the impact of intermittency. Therefore, the power/energy output from offshore wind sites based on the assessed wind resource in Figures 6.4 to 6.21 and the 8 and 10 MW turbine power curve characteristics is used to analyse the impact of offshore wind intermittency on electricity sector decarbonisation by 2030.

The mean annual wind speeds for the nine offshore wind sites shown in Figure 6.22 confirm the views of the Energy Technologies Institute that the UK has the Europe's biggest offshore wind resource, probably accounting for over a third of the total European potential (ETI, 2015). The mean annual wind speeds for the different weather stations for the UK offshore wind development range between 7 m/s and 8.6 m/s with the highest recordings corresponding to 80 m hub height as shown in Figure 6.22. For example, the maximum mean wind speeds of between 7.6 m/s to 10.8 m/s were observed at Ronaldsway at 80 m hub height during the spring, autumn and winter seasons. This trend is replicated in all the assessed weather stations regardless of the height at which the wind resource is recorded. This seasonal resource characteristic observed at the selected offshore wind sites concurs with the assessment in Coker et al. (2013) suggesting greater incidences of high wind speed during winter and spring with pronounced high and low wind events lasting several days, at all times of the year.

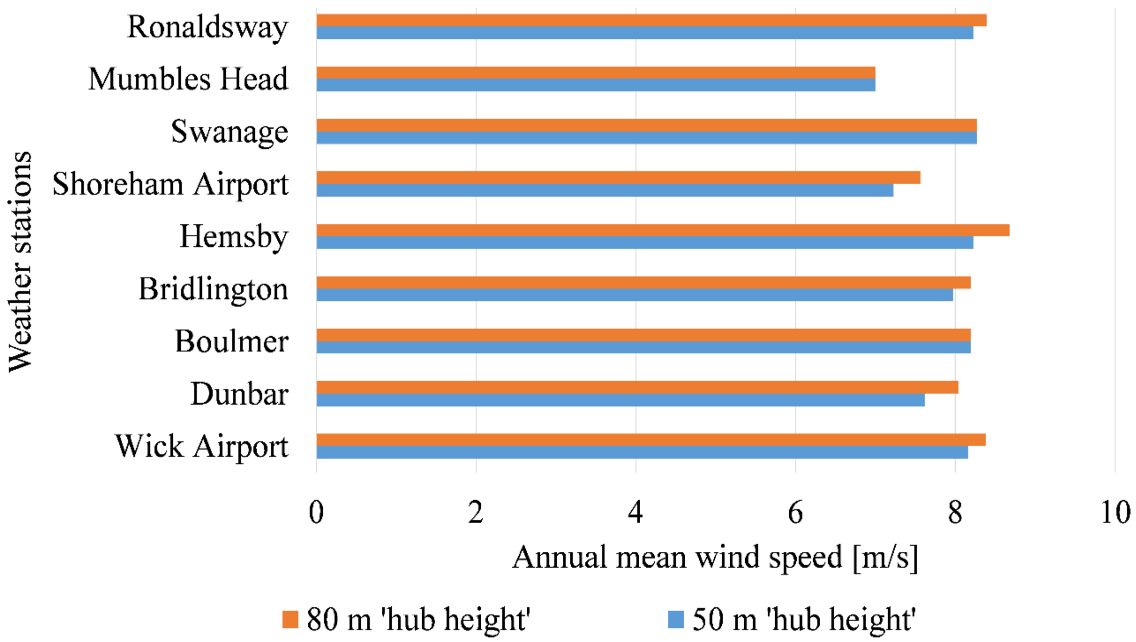

Figure 6.22. The annual monthly averages of wind speed for the nine offshore wind stations.

The summer wind speed averages at 50 and 80 m hub heights at all the nine weather sites range between 5.7 to 6.8 m/s and 6 to 7.2 m/s, respectively. While the UK summer season is synonymous with low average wind speeds, the wind resources demonstrated at the selected weather stations during this period is sufficiently high to allow a sustained offshore wind power output. The huge energy potential in the offshore wind resource demonstrated in Figures 6.4 to 6.22 has significant implications on the power and energy yields which are required to meet the UK's electricity demand and to assist in decarbonising the electricity supply sector by 2030. The extent to which the UK offshore wind resource is harnessed to meet energy policy ambitions is discussed in the following sections.

6.2.3 Intermittent offshore wind: power output and sector decarbonisation

In its original design, the EOC does not take into account the impact of variance in output from renewable energy technologies such as offshore wind in the development of scenarios for energy system transitions. To this end, the optimisation function of the model allocates the maximum installed generation capacity of offshore wind assuming that the allocated power capacity would supply demand at a constant rate throughout the year. Offshore wind is ranked amongst the low-carbon energy technologies expected to contribute in driving down GHG emissions during the fifth carbon budget period (2028–2032) (CCC, 2015). Therefore, it is vitally important that a modelling environment designed to be a credible source of information to policymakers, renewable energy developers and investors on the potential contribution of offshore wind to electricity sector decarbonisation should endeavour to incorporate the key issues underpinning the dynamics affecting renewable energy technologies such as variability.

The energy output from wind farms in general varies with environmental conditions, such as wind strength and frequency, which unfortunately are beyond the control of utility operators. These factors have a potential to influence the power/energy output from offshore wind which in turn can impact on the operation of the electricity network. While the geographical distribution of the offshore wind developments (see Section 3.3.7) could significantly reduce the fluctuations in wind output across the UK, it is crucial that the full extent of variance in intermittent power/energy output from offshore wind energy resources is ascertained. In this respect, the power/energy performance of each offshore wind farm is determined based on the wind resource characterisation presented in Figures 6.4 to 6.22 combined with the turbine power curve (illustrated in equation 3.14 in Section 3.3.7.2) of the 8 and 10 MW rated power wind turbines at different hub heights as shown in Figures 6.23 and 6.24.

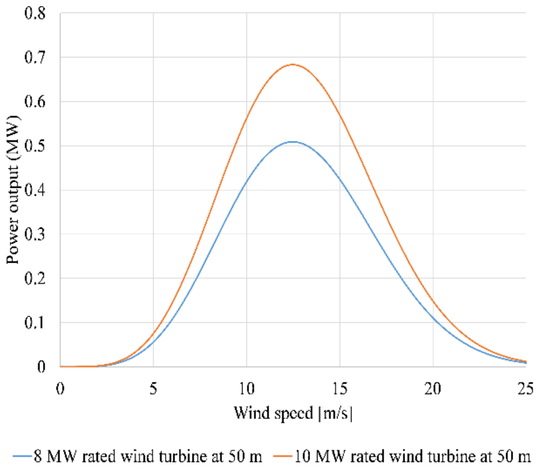

Figure 6.23. Turbine power output at Norfolk offshore wind farm–turbine power curve and wind resource characteristics at Hemsby station.

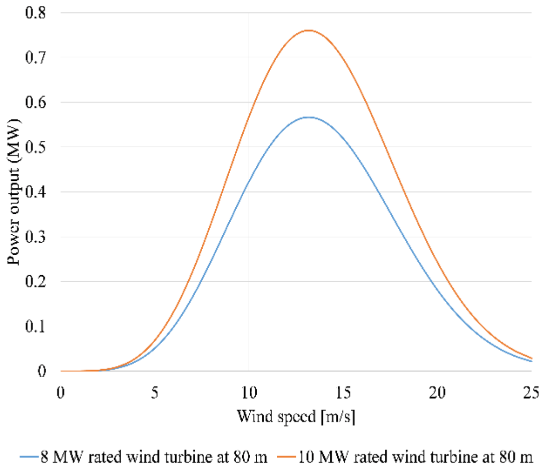

Figure 6.24. Turbine power output at Norfolk offshore wind farm–turbine power curve and wind resource characteristics at Hemsby station.

Having determined the turbine power performance at a given offshore wind farm site as shown in Figure 6.23 and 6.24, the total power output of the entire offshore wind farm is calculated taking into account the total number of turbines at each development site. A comparison of the turbine power output between 8 and 10 MW rated wind turbines at 80 m height (see Figures 6.23 and 6.24) shows a 2.04 MW difference in favour of the 10 MW capacity turbine due to a larger swept area. The 10 MW wind turbine model at 80 m height could emerge as the most preferable offshore wind technology option likely to be deployed through the 2020s to achieve the capacity levels required for the 2030 energy scenario because of its potential capacity to maximise power output. Since the variability nature of wind has a potential to reduce the power/energy output from offshore wind farms, the deployment of this wind turbine model could still increase the output from offshore wind despite the negative impact of intermittency as outlined in the following sections. The proportional power output achieved at each of the nine offshore wind farm sites is determined based on the approach illustrated in Figures 6.23 and 6.24 and the results are highlighted in Figure 6.25.

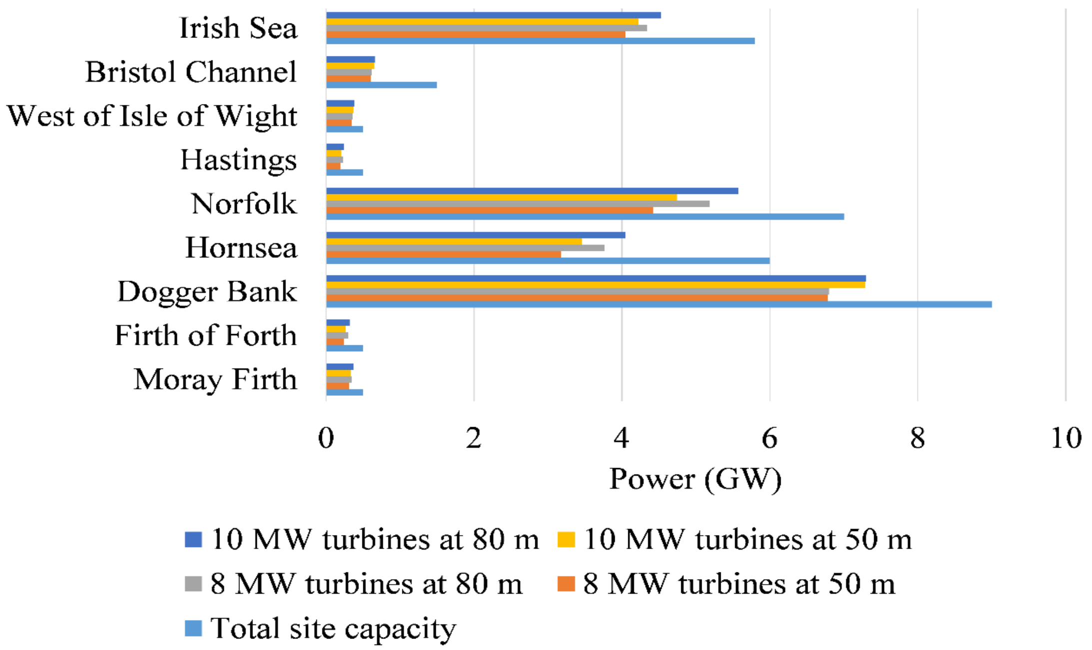

Figure 6.25. Total power output at each wind farm site relative to the site power capacity.

The results shown in Figure 6.25 respectively indicate that a wind farm site with 8 MW wind turbines powered by winds blowing at 50 and 80 m height produce an average power output of 58 % and 64 % of the total installed capacity. On the other hand, offshore wind farm sites with 10 MW turbines exposed to wind streams blowing at 50 and 80 m height achieve an average power output of 62 % and 70 % of the total installed capacity. The SeaTitan 10 MW has a greater potential to capture the energy in moving wind due to its huge swept area (28353m^2) compared to the V164-8.0 MW (21124m^2) (AMSC, 2012; MHI Vestas Offshore Wind, 2014), and hence the difference in power output at the same height as exhibited in Figure 6.25. The influence of wind characteristics at different heights on turbine power output is demonstrated by a 0.02 % increase in the average power output of the V164-8.0 MW at 80 m over the SeaTitan 10 MW at 50 m despite the later having a greater swept area (see Figure 6.25).

It is important to note that there is on average a 0.05 % and 0.1 % difference in the amount of power produced by each wind turbine model at 50 and 80 m, and hence the small difference in the aggregated power output from the offshore wind farms shown in Figure 6.26.

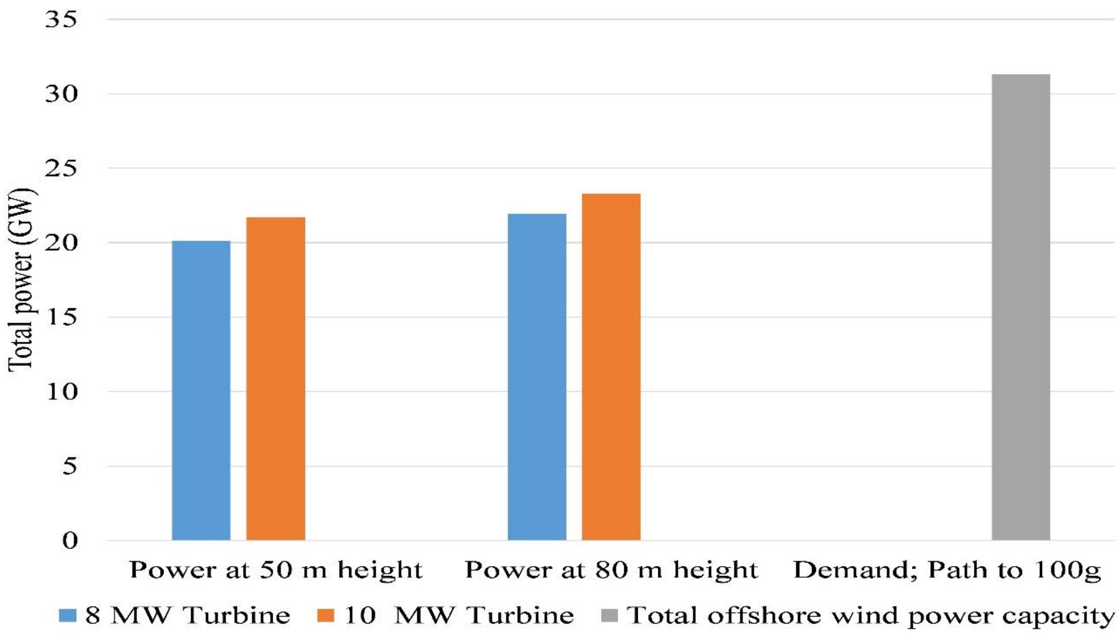

Figure 6.26. The aggregated power output from offshore wind sites relative to the 2030 scenario capacity.

While exposed to respectively high wind speeds blowing at 50 and 80 m height, the cumulative power output of wind farms with the V164-8.0 turbines is about 20.1 and 21.9 GW. As the SeaTitan 10 MW's wind power capture potential is boosted by its greater swept area, which is about 1.3 times larger than that of the V164-8.0, the aggregated power yield from the offshore wind farms is 21.7 and 23.3 GW (see Figure 6.26) at 50 and 80 m height, respectively. The scenario developed by the Energy Optimisation Calculator for the 'path to 100 g' by 2030 projects 31.3 GW of offshore wind capacity required to contribute towards the energy demand and electricity sector decarbonisation by 2030. The offshore wind power output portrayed in Figure 6.26 indicates that the 8 MW rated power turbines at 50 and 80 m height could respectively accrue a power shortfall of about 36 % and 30 % relative to the modelled target required to contribute towards meeting the UK energy demand as well as cutting greenhouse gas emissions. Similarly, the 10 MW turbines on the same offshore wind developments powered by winds moving at 50 and 80 m height fall short of the 31.3 GW projected offshore wind capacity by 31 % and 26 %, respectively.

The difference in the total aggregated power capacity between the assessed offshore wind farms and that of the optimised capacity set by the model (see Figure 6.26) demonstrates the impact of variability, a major characteristic of weather based renewable energy sources. Assuming that the model's projected overall offshore wind capacity to meet energy demand and to decarbonise the electricity supply infrastructure by 2030 is derived from the assessed nine wind farms, it implies that more offshore wind capacity would need to be developed to cater for the variability induced shortfall in order to achieve the target set by the model. By so doing, the full impact of wind energy variability on the energy system development could be reflected, and thus proving vital insights into policy and energy supply infrastructure development.

The electricity supply output shown in Figure 6.27 is reflective of the proportionate power yields demonstrated in Figure 6.25. The electricity generation outlay from the assessed offshore wind farms is calculated based on a 34 % capacity factor. The offshore wind electricity generation output determined by the model for the scenario achieving a 100 g/kWh carbon grid intensity is 80.6 TWh, assuming a capacity factor of 29.4 % (see Figure 6.1). In the context of the model estimated contribution from offshore wind by 2030, the aggregated energy supply from the 8 and 10 MW rated turbine wind farms with the wind resource captured at 50 and 80 m heights is 59.2 and 64.5 TWh and 63.3 and 68.9 TWh, respectively.

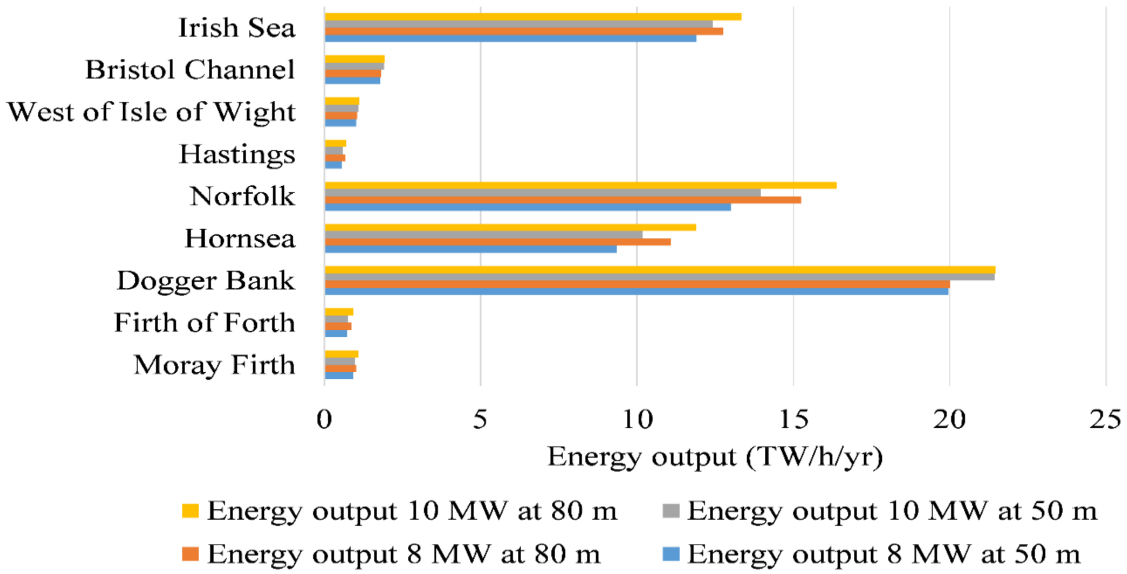

Figure 6.27. Energy output from offshore wind farms based on different turbine models and hub heights.

Wind variability induced deficit to the projected offshore wind contribution to the generation mix by 2030 is illustrated in Figure 6.28, where the electricity supply calculated based on wind data analysis fails to achieve the estimated supply target. It is noticeable from Figure 6.28 that the capacity of the 8 and 10 MW turbines to capture and convert wind power at 50 and 80 m height fail to reach the 80.6 TWh target by about 21.4 and 16.1, 17.3 and 11.7 TWh, respectively. The energy supply deficit illustrated in Figure 6.28 underscores the full impact of the intermittent nature of wind energy resources on the future contribution of offshore wind energy technologies on the generation mix. However, with wind turbine innovation and development such as the SeaTitan 10 MW model developed to capture wind speeds at 80 m and above, there could be an increase the wind power capture potential, and thus reducing the full impact of variability on total power/energy output achieved from offshore wind farms.

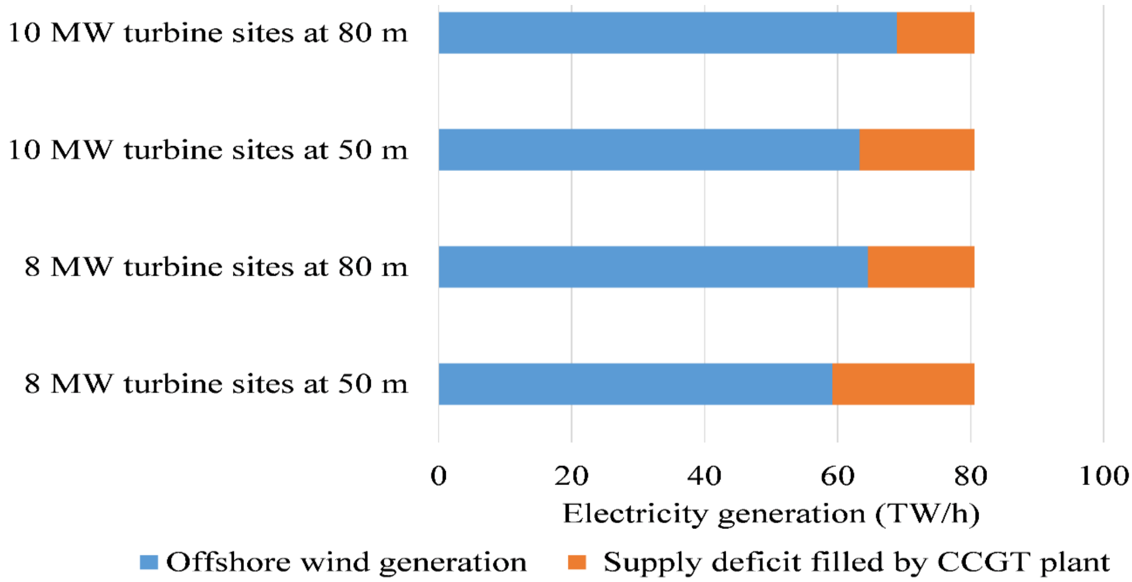

Figure 6.28. Electricity supply deficit resulting from variance in intermittent offshore wind output.

Studies on the impact of renewable energy variability on electricity systems have in general sought to quantify the value of capacity credit, that is, the capacity of fossil fuel generation that can be displaced from the electricity supply system. Other approaches to variability in electricity system assessments have focused on establishing the level of intermittent output and the degree of correlation between demand peaks and the intermittent output (Gross et al., 2006). While these study areas on the implications of variability of some renewable energy source offer valuable insights in understanding the economics, energy security and climate change related impacts on the electricity supply transition to a low-carbon futures, the scope of this thesis aims to understand and quantify the variance of offshore wind intermittent output visa vis electricity supply sector decarbonisation aspirations by 2030. As this research does not endeavour to assess the cost of offshore wind generation relative to conventional generation, Figure 6.29

highlights the capacity of back-up fossil fuel plant that could be required to mitigate offshore wind intermittent output. The electricity generation outlay from CCGT plants (see Figure 6.28) used to mitigate the supply deficit created by variance in offshore wind output is used to determine the reserve CCGT capacity portrayed in Figure 6.29.

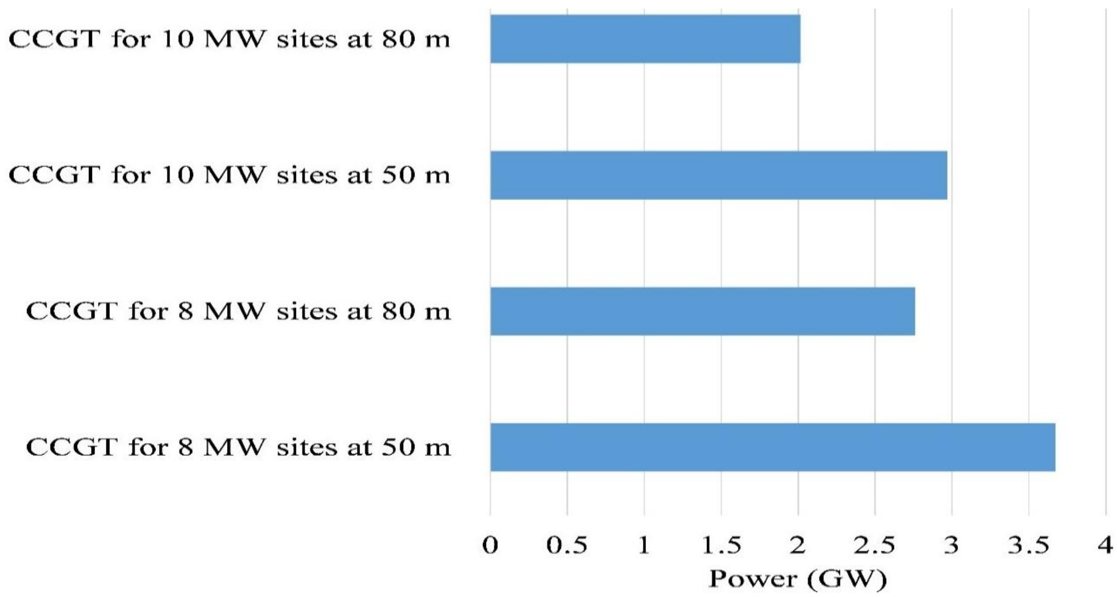

Figure 6.29. Back-up fossil fuel plant capacity to meet the electricity demand deficit resulting from the variance of offshore wind output.

The level of CCGT plant capacity presented in Figure 6.29 would need to be incorporated into the generation mix in 2030 in order to maintain the reliability of the electricity supply system as a result of the capacity deficit created by the variability of offshore wind. The maximum back-up fossil fuel plant capacity of 3.7 GW is required to meet the demand deficit from offshore wind farms with 8 MW turbines powered by winds at 50 m height while the remainder of the wind farm sites have a back-up capacity of less than 3 GW as shown in Figure 6.29. The level of offshore wind penetration from the nine offshore wind sites with 8 and 10 MW rated turbines, powered by winds at 80 m height represent about 20% of the total installed capacity. This level of renewable energy penetration is assessed based on the optimal generation mix modelled by the calculator in line with the 2030 carbon grid target of 100 g/kWh. In terms of the capacity credit, a measure of the contribution of intermittent generation to system reliability (Gross et al., 2006), the 20 % offshore wind penetration (from the 8 and 10 MW turbines at 80 m height) has a capacity credit of approximately 20-30 % in line with the UK conditions (Gross et al., 2006). Generally, the capacity credit for intermittent generation from the offshore sites (see Figure 6.26) assessed for the purpose of this thesis is considerably high, which implies that less capacity from dispatchable generation would be required to maintain system reliability. Although the economic implications of providing a dedicated back-up capacity to mitigate variance in intermittent output is beyond the scope of this study, Milborrow (2009) suggests that a 20 % wind penetration with an assumed capacity factor of 35 % could have the effect of reducing the load factor of the thermal generation plants. As a result, the generation cost of thermal plants increases as capital cost repayments are spread over reduced generation output, and thus providing the basis for estimating the additional cost of back-up (Milborrow, 2009). Based on the up to date CCGT price of £700/kW, a 20 % and 40 % wind penetration level could approximately incur additional back-up cost in the region of about £2.5/MWh and £6/MWh, respectively (Milborrow, 2009). As the additional costs for maintaining system reliability are bound to be passed down to the consumer, this could negatively impact on the energy policy objective of promoting the delivery of affordable energy supplies to consumers through low-carbon energy development.

The reserve capacity required to mitigate variance in intermittent output from offshore wind portrayed in Figure 6.29 would have to be operated at a capacity factor of 66 % in order to achieve the electricity demand deficit shown in Figure 2.28. Offshore wind generation, as with the majority of renewable energy technologies, is highly anticipated to contribute towards decarbonising the electricity supply systems by reducing the amount of unabated carbon intensive fossil fuel plants such as coal and gas. However, while offshore wind, a low-carbon technology is considered to be one of the key players which could steer the UK electricity supply sector towards the 100 g/kWh carbon grid intensity target by 2030 (CCC, 2015), the inherent intermittent nature of wind brings along the emission penalty owing to the requirement to use back-up fossil fuel plant to promote energy system adequacy. In the light of this assessment, Gross et al. (2006) noted that wind energy does not reduce carbon dioxide emissions since the intermittent nature of its output requires back-up by fossil fuel plant.

The fifth carbon budget set the cumulative emission from the electricity supply sector at about 31 $MtCO_2e$ in order to achieve the 100 gCO_2/kWh decarbonisation target by 2030 (CCC, 2015). The optimised generation mix developed by the Energy Optimisation Calculator achieves the 2030 carbon grid carbon intensity with a cumulative emission inventory of 34 $MtCO_2e$, and hence the proportion of emissions from intermittent offshore wind relative to the 2030 target portrayed in Figure 6.30. The European Environmental Agency (EEA) argues that the future technological development of wind energy could result in the 10 MW rated wind turbines dominating the offshore wind farms by 2030 (EEA, 2009). Assuming that this technological progress in offshore wind power supply system is realised, Figure 6.30 indicates that offshore wind farms with 10 MW turbine installations at 50 and 80 m height could respectively have a cumulative intermittent induced carbon emission of 1.4 and 1 $MtCO_2e$. It is important to note that this observation on the emission performance of this wind turbine model deployed at different heights is assessed in the context of the 'path to 100 g' transition pathway by 2030. Therefore, this implies that the impact of intermittence based on the technological progress in offshore wind turbine development could increase the cumulative electricity supply emissions to 35.4 and 35.8 $MtCO_2e$, respectively. In the context of the fifth carbon budget's carbon emission grid intensity target, the cumulative emissions from 10 MW turbine offshore wind farms powered by wind speeds at 50 and 80 m height could equate to a carbon grid intensity of 103 and 104 g/kWh by 2030.

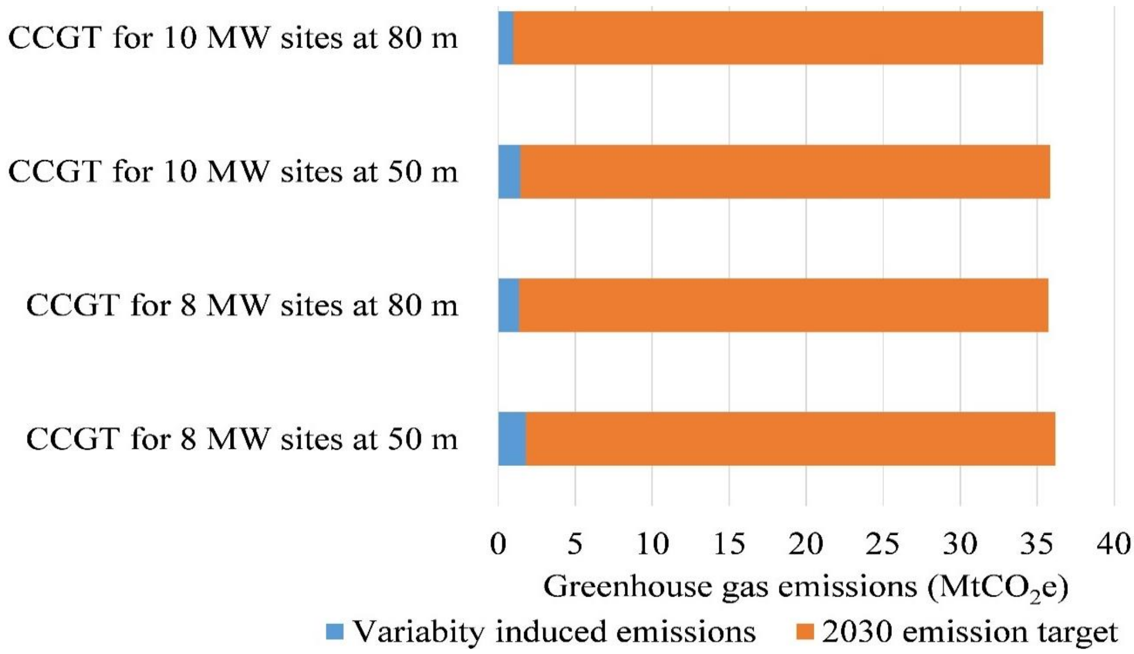

Figure 6.30. The environmental impacts of intermittent offshore wind to electricity sector transition to a low-carbon future.

Although the 8 MW rated turbine currently represents the third largest offshore wind turbine by capacity (Power-technology.com, 2014), the EEA envisages that it could dominate the offshore wind generation landscape by 2020 (EEA, 2009). In the event that this turbine technology progresses to shape the offshore wind farm development outlook by 2030, the emission outlay presented in Figure 6.30 indicates that emission target for the electricity sector decarbonisation (34.4 $MtCO_2e$) could respectively increase by 1.8 and 1.3 $MtCO_2e$ to reach 36.2 and 35.7 $MtCO_2e$ owing to the influence of variable output from wind. The overall emission performance of the 8 MW rated power turbines across the offshore wind farms powered by winds blowing at 50 and 80 m heights could increase the 2030 decarbonisation emission target by 5.2 and 3.8% to reach 104 and 105 gCO_2/kWh.

The increase in the amount of emissions resulting from the variance in intermittent output from offshore wind is relatively small. Therefore, it is highly unlikely that the intermittent induced emissions could negatively impact or derail the wider policy ambition of guiding the UK economy towards the 2050 legally binding emission reduction target. Having established the nature of the wind resource expected to power the offshore wind for the 2030 UK generation mix, the increase in the emissions derived from the intermittent wind displayed in Figure 6.30 could be mitigated by increasing the penetration levels of wind in the mix. However, this premise is based on the assumption that the assessed offshore wind characteristics would deliver power output consistently throughout the period under study. Although low wind events are likely to be experienced over the course of the year, the analysis undertaken in this thesis is of the view that as wind capacity in the system increases, the increased geographical spread of offshore wind developments could reduce the energy output fluctuations and any significant changes in wind output across the whole of the UK (Milborrow, 2009).

In the event that the intermittent output drops below the levels portrayed in Figure 6.26 due to low wind output over the whole of the UK offshore wind site developments, the proportion of back-up capacity and the emission outlook in Figures 6.29 and 6.30 could increase. However, the implications of such an increase in the intermittent induced emissions over the overall UK economy decarbonisation aspirations could be dependent on the emission reductions from other sectors of the economy. In any case, a 20 % offshore wind penetration which is geographically widespread across the British territorial waters is not likely to underperform to the extent of derailing the entire economy from the path to the 2050 emission reduction target.

6.2.4 Wind variability in the 'Energy Optimisation Calculator'

The offshore wind analysis undertaken in Sections 6.2.2 and 6.2.3 has exposed the inadequacies of the model used in this thesis to address the issue of intermittency from renewable energy sources, particularly from offshore wind. The optimised low-carbon and renewable energy technology capacities projected by the model to meet emission reduction targets appears to have been overestimated as demonstrated by the analysis carried out in this section. This is borne from the fact that the contribution from some of the renewable energy sources to the generation mix did not incorporate the potential output differential resulting from variability associated with weather. A comparison of the total offshore wind capacity in the context of a 100 gCO_2/kWh decarbonisation target portrayed in Figures 6.1 and 6.29 shows that variance in intermittent output reduces the power capacity of offshore wind determined by the calculator by an average of about 30 %. Having quantified the level of intermittent output from offshore wind, it is vitally important that this aspect is reflected in the model framework in order to improve and enhance the plausibility of the scenario outputs developed by the model. Ultimately, as the robustness of the scenario outputs from the model are ascertained, a level of confidence could be ascribed to the EOC as one of the key modelling frameworks that could be used to provide insight into policy, technological and electricity supply infrastructure development.

While there is no need to modify the fundamental optimal cost and emission abatement mathematical framework of the model, the crux of the matter centres on the need to ensure that the intermittent renewable energy capacity computed in the model has been synthesised to incorporate variability. Running the model in its original state should only provide a benchmark of the level of renewable energy capacity that could be required to meet energy demand and emission target set, optimally. With the UK offshore wind developments geographically spread across the British Isles, the actual renewable energy (offshore wind) capacity and the capacity factor can be assessed based on site and turbine characteristics by adopting an integrated approach which employs other analysis tools such as the MERRA to be assessed outside of the EOC. The methodology and analysis framework outlined in Sections 3.3.7.1, 6.2.2 and 6.2.3 could form a blueprint by which the intermittent output from wind can be ascertained before the indicative capacity can be computed into the model.

The technical plant utilisation/availability factor used in the calculator determines the percentage of the time the electricity generation plant is available to produce energy (Feng et al., 2010). As a function of plant reliability, the EOC sets the utilisation factor for renewable energy sources at 70 % while unabated and CCS fitted fossil fuel and nuclear power plants are operated at 80 %. In determining the energy output of any given plant within the model, the capacity factor is reduced in line with the utilisation factor ascribed to each power generating plant. For example, based on the 70 % utilisation factor, a 42 % capacity factor for offshore wind implies that the overall energy output is calculated using a 29.4 % capacity factor, having accounted for the 30% of the time the generating plant is unavailable to produce electricity to the grid.

As modern wind turbines have a guaranteed availability of about 95 % (Salvacao & Guedes Soares, 2015), this utilisation factor would need to be incorporated in the calculator to replace the original capacity allocated to offshore wind. Therefore, in ensuring that the offshore wind capacity factor is reflective of the site wind data and turbine characteristics, the value computed in the model would be increased by about 5 % to cater for the plant unavailability which the model deducts in its calculations. Once the level of intermittency is quantified and the model settings are configured to assimilate the element of intermittency from offshore wind or any other renewable energy resources, then confidence can be ascribed to the model's capability to develop low-carbon energy scenarios that truly reflect on the dynamic impacts of variability on some of the renewable energy sources.

6.2.5 Summary

The UK has an abundant offshore wind resource which is vital to offshore wind energy development. While the future role of offshore wind in contributing towards meeting the domestic and regional renewable energy and emission reduction targets is unequivocal, wind energy is intermittent in nature. Variable energy output from renewable energy technologies such as offshore wind have the potential to impact on the operation and economics of electricity networks, markets and the output of other forms of generation (Gross et al., 2006). Thus, it is important that energy modelling environments are developed in a manner that quantifies the level of variance in intermittent output from renewable energy resources including wind.

Assuming that the total offshore wind installed capacity from the nine offshore wind development zones constitutes 31.3 GW, the aggregated output from all the wind farm sites could respectively achieve a power capacity outlay of about 20.1 and 21.9 GW and 21.7 and 23.3 GW from 8 MW and 10 MW turbines at 50 and 80 m heights. The difference between the total installed capacity and aggregated power output from the wind farm development zones serves to highlight the level of variability induced by environmental conditions on offshore wind.

In the context of the 100 gCO_2/kWh grid carbon intensity decarbonisation target, variance in intermittent output from offshore could results in a supply deficit which could be mitigated by adding unabated fossil fuel plants to the generation mix, thereby increasing the level of carbon emissions relative to the 34.4 $MtCO_2e$ target set for the electricity sector decarbonisation by 2030. A 10 MW rated wind turbine at 80 m height has a high energy output which results in less unabated reserve gas plant generation capacity being deployed to mitigate the supply deficit created by the variance in intermittent output. The increase in the amount of emissions resulting from the variance in intermittent output from offshore wind is relatively small. Therefore, it is highly unlikely that the intermittent induced emissions could negatively impact or derail the wider policy ambition of guiding the UK economy towards the 2050 legally binding emission reduction target.

Chapter 7 Conclusions and future work

7.1 Conclusions

The new UK energy policy may not achieve the deployment targets for new gas and nuclear generation plants. The supply gap created could be filled by unabated coal and diesel generators, thus compromising on the decarbonisation ambition especially in the absence of CCS technology in the mix. The UK new energy policy would need to be revised in line with the Climate Change Act in order to build a strong link between security of supply and a low-carbon electricity supply system. Thus, an accelerated deployment of CCS, conventional and SMR nuclear plants and renewable energy technologies after 2030 is central in developing a near zero carbon grid intensity electricity generation sector by 2050.

The potential shale gas use in unabated gas plants could be limited in decarbonisation pathways which achieve 50 and 100 gCO_2/kWh by 2030. The increased use of shale gas in electricity generation could be enhanced in gas plants retrofitted with CCS technology. Based on this limited operational regime of unabated gas plants in the 50 and 100 gCO_2/kWh decarbonisation targets by 2030, the introduction of shale gas in the generation mix may not alter the low-carbon and renewable energy technology development and deployment framework required to cut carbon emissions. The benefits of shale gas in the electricity generation could be realised under large decarbonisation targets such as the 'path to 200 g' where unabated gas plants are operated at high capacity factors. Thus, the penetration of low-carbon and renewable energy technologies is curtailed by the increased use of shale in unabated gas plants in this scenario. Therefore, shale gas development and use in the UK electricity generation sector has limited benefits unless used plants fitted with CCS.

Renewable energy technologies contribute significantly to developing low-carbon electricity supply systems. Their energy output is variable due to environmental conditions. The UK has an abundant offshore wind resource. Based on the energy scenario that achieves the 100 g/kWh carbon grid intensity by 2030, the aggregated offshore wind energy output from the 8 and 10 MW rated WT at 50 and 80 m height could respectively be mitigated by 2.8 and 2 GW capacity of unabated gas CCGT. Therefore, the emissions resulting from intermittency are in the order of 3 to 4 %, which by all accounts is not likely to affect the UK decarbonisation targets.

7.2 Research limitations

Intermittency of renewable energy resources such as onshore wind, solar PV, Wave and tidal is not assessed in this research. These energy resources are distributed over a large geographical scale across the UK. Hence, time and data availability have been key factors that constrained this research from incorporate the assessment of intermittency of these renewable energy technologies. A study on the impact of variability on offshore wind is not modelled to evaluate the interaction between intermittent out, peak demand and the operation of dispatchable generation. This is constrained by time, data as well as the model framework which is limited in its assessment of the peaks and troughs in electricity demand. The research did not examine the evolution of the whole UK energy system to a low-carbon future. The scope of the EOC is only focused on developing scenarios for decarbonising the electricity generation sector in line with the 2050 emission reduction target. Due to the model limitations, other sectors of the energy economy such as the built environment, industry and transport have not been integrated in this research.

7.3 Future research

The UK electricity generation could remain dominated by fossil fuels dominated well beyond the 2030s in the context of the current policy developments. An integrated modelling approach which incorporates the EOC, PLEXOS and ESME could be employed to develop scenarios that reflect on the whole energy system. It is through this whole system analysis approach that suitable policy, technological and economic mechanisms could be put in place to support some sectors of the energy economy which were once deemed too expensive and difficult to precipitate deep cuts in emissions.

Variability of renewable energy sources examined in this research is confined to offshore wind. Furthermore, the analysis is limited in detail as it doesn’t explore the short-term fluctuations in offshore wind output. Hence, the interaction between intermittent output, peak demand and the operation of a reserve fossil fuel plant is not explored in this thesis. These aspects are critically important in determining the way the electricity system works. In this respect, the scope of the research planned for the future on this subject could initially focus on mapping the renewable energy resource (wind, solar and wave), followed by the quantification of variability on onshore wind, solar PV, tidal and wave output based on statistical data analysis. The next phase of this analysis would progress to evaluate the short-term implications of renewable energy intermittency to system reliability and the cost of maintaining and operation of the reserve generation plant. The EOC could be used in conjunction with PLEXOS to simulate the economics, technical and operation levels of fossil fuel and renewables technologies within the generation mix.

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Appendices A: The interactive interface of the ‘Energy Optimisation Calculator

Appendices A1 to A4 show the data input worksheets which represent the interactive interface of the ‘Energy Optimisation Calculator’. The green colour coding shown on worksheets indicates the data input used to develop the energy transition pathways as determined by the user. The yellow colour on the worksheets are the calculated result elements based on the background optimisation operations of the model. The worksheets are arranged in the order in which the data is computed up until the results are presented after the model has complete each run or scenario development process as shown in Appendices A3 and A4.

A1: United Kingdom_Input_Sheet

United_Kingdom	INPUT DATA																
OVERALL PARAMETERS								**Emissions Factors**				**Misc**					49.5
	LMS Generation	379.2	TWh/a		NumTech=	16						Indirect Stem:	United_Kingdom_in				19.8
	LMS Total GHG Emiss	185.8	Mte CO2e /a					*LMS g/kWh*	*489.9789*	*Calculated*							
	HMS Generation	344.0	TWh/a														
	EmissionsTarget	34.4	MteCO2/a					*HMS g/kWh*	*100*	*Calculated*							
	OPEX_Percent_Defaul	3	Percent of CA	*Used unless specified for each tech*													
	ALT_opex_localisation	1	Factor														
	USED_opex_localisati	1	Factor	*Cost localisation factor actually used*													
NEW ELECTRICITY GENERATING TECHNOLOGIES/MIX (HMS)																	
						Overall Efficienc	Network			Physical	***Load factor development***						
	Technology	CAPEX £/GW	OPEX £/a	LearningRa	Fuel cost £ per GW	Fuel to Power	Utilisation Factor	Load Factor (LF1)	kgCO2/KWh(	Installation Limit IL (GW)	IC1 (GW)	LF2	IC2	LF3	IC3	LF4 (at IL)	
				(not used)													
	Wind Onshore	1596000000	7.50E+06	0	0	1	0.7	0.27	0.003	18	#######	0.27	#######	0.27	1.35E+01	0.27	
	Wind Offshore	2851000000	1.82E+07	0	0	1	0.7	0.42	0.005	50	#######	0.42	#######	0.42	3.75E+01	0.42	
	Pumped Storage	1958000000	1.17E+06	0	0	1	0.8	0.18	1.50E-02	3	7.50E-01	0.18	#######	0.18	2.19E+00	0.18	
	Solar PV	780000000	2.03E+06	0	0	1	0.7	0.11	0.04	18	#######	0.11	#######	0.11	1.35E+01	0.11	
	Hydro	2417000000	8.94E+06	0	0	1	0.8	0.37	0.01	2	5.00E-01	0.37	#######	0.37	1.50E+00	0.37	
	Nuclear	4427760000	9.30E+06	0	8000	0.33	0.8	0.8	0.005	14	#######	0.8	#######	0.8	1.05E+01	0.8	
	Biomass	2532000000	1.52E+07	0	23292.25427	0.261	0.8	0.6	0.27	4	#######	0.6	#######	0.6	3.00E+00	0.6	
	BECCS	4117780000	1.32E+07	0	23292.25427	0.375	0.8	0.85	-0.9	3	7.50E-01	0.85	#######	0.85	2.25E+00	0.85	
	Interconnectors	539196563	1.05E+07	0	0	0.44	0.7	0.5	0.004	10	#######	0.5	1.25E-01	0.5	7.50E+00	0.5	
	Gas CCGT	598500000	2.27E+06	0	49519.096	0.64	0.8	0.6	0.488	35	#######	0.6	#######	0.6	2.63E+01	0.6	
	Coal CCS	3916120000	1.02E+07	0	66391.07	0.335	0.8	0.85	0.189	6	#######	0.85	#######	0.85	4.50E+00	0.85	
	Gas CCGT CCS	1369030000	3.97E+06	0	7648.696	0.508	0.8	0.85	0.07	6	#######	0.85	#######	0.85	4.50E+00	0.85	
	Wave	3610000000	1.99E+07	0	0	1	0.7	0.28	0.025	3	7.50E-01	0.28	#######	0.28	2.25E+00	0.28	
	Tidal	2750000000	3850000	0	0	1	0.7	0.24	0.025	4	1	0.24	2	0.24	3	0.24	
	Conventional CHP	617940000	4696344	0	49519.096	0.384	0.8	0.3	0.488	3	0.75	0.3	1.5	0.3	2.25	0.3	
	Renewable CHP	4272000000	32467200	0	23292.25427	0.3	0.8	0.3	0.27	8	2	0.3	4	0.3	6	0.3	
LOW MITIGATION MI	Technology	Decimal Percent Ca	Percent Gene	Load Facto	GHGEmissions	Minimum Capac	Representative OPEX	FUELCOST	Overall Effy	Utilisation factor		*InstCap GW*	*Annual*		*Annual Fuel*	*Opex*	*Constructi*
		Calculated			kgCO2/KWh(e.)	GW	USD/GWh	USD/GWh(fuel)	Fuel to Power				*Gen (TWh)*		*US$/yr*	*US$/yr*	*Cost (US$)*
	Wind Onshore	0.027096774	0.02	0.27	0.003	1.00	3169.315791	0	1	0.87		2.1	4.97032		0	1.58E+07	3.35E+09
	Wind Offshore	0.00516129	0.01	0.28	0.005	1.00	7433.916756	0	1	0.87		0.4	0.98179		0	7.30E+06	1.14E+09
	Pumped Storage	0.03483871	0.03	1.61E-01	0.015	1.00	832.408671	0	1	0.87		2.7	3.81058		0	3.17E+06	5.29E+09
	Solar PV	0	0.00	1.10E-01	0.04	1.00	0	0	1	0.87		0	0		0	0.00E+00	0.00E+00
	Hydro	0.018064516	0.01	0.363	0.01	1.00	2810.413889	0	1	0.87		1.4	4.45488		0	1.25E+07	3.38E+09
	Nuclear	0.140645161	0.13	0.596	0.005	1.00	1779.736229	8000	0.9	0.87		10.9	56.9474		506199.49	1.01E+08	4.83E+10
	Biomass	0.020645161	0.03	0.56	0.2	1.00	3094.749193	23292.25427	0.4	0.87		1.6	7.85434		457362.98	2.43E+07	4.05E+09
	BECCS	0	0.00	0.5	-0.9	1.00	0	23292.25427	0.35	0.87		0	0		0	0.00E+00	0.00E+00
	Coal	0.362580645	0.32	0.625	0.78	1.00	1909.270057	0	0.45	0.87		28.1	153.953		0	2.94E+08	1.52E+10
	Gas	0.390967742	0.39	0.632	0.488	1.00	410.5151665	49519.096	0.6	0.87		30.3	167.865		1.385E+10	6.89E+07	1.81E+10
	CoalCCS	0	0.00	0.5	0.19	1.00	0	66391.07	0	0.87		0	0		0	0.00E+00	0.00E+00
	GasCCS	0	0.00	0.5	0.07	1.00	0	7648.696	0	0.87		0	0		0	0.00E+00	0.00E+00
	Wave	0	0.00	0.5	0.025	1.00	0	0	0	0.87		0	0		0	0.00E+00	0.00E+00
	Tidal	0	0.00	0.5	0.025	1.00	0	0	0	0.87		0	0		0	0.00E+00	0.00E+00
	Conventional CHP	0.067096774	0.06	0.58	0.18	1.00	0	49519.096	0.384	0.87		5.2	26.4383		3409371.2		
	Renewable CHP	0.067096774	0.01	0.58	0.2	1.00	0	23292.25427	0.3	0.87		0.16	0.81348				
	SUM	1.067096774	0.93606383									82.7	400.838		1.386E+10	527250631	9.9E+10

A2: Master Control Sheet

MASTER CONTROL SHEET	Update Data	Run!				*Pale Green = Can Change*	*Yellow =Updated Automatically*							
INPUT DATA						CALCULATION CONTROL								
Economic Parameters								GHG Emissions (Mte CO2e)		Power Generation(TWh/a)			LCS Reduction	Reduction
Lifetime (Master)	30	years					Calculate?	LMS	LCS_Target	LMS	LCS		Factor	Modifier
DiscRate	0.1	Decimal percent				United_Kingdom	YES	185.8	156	379.2	316.9		0.01015	0.940237389
Start Year	1997					Eastern_Europe	NO	628.5	6.381323592	2389.5	3801		0.01015	0.940237389
End Year	2027					North_America	NO	3386	36.56410292	6571	9941		0.01080	1
						Latin_America	NO	485	4.924330854	1792	2631		0.01015	0.940237389
						China	NO	4876	54.76019742	8064	16373		0.01123	1.04
Global Fuel Costs			Lo	Hi		India	NO	2040	22.4697535	3285	6433		0.01101	1.02
Use Global Costs	YES	YES/NO				Asia_Oceania	NO	598	6.071649177	1493	2924		0.01015	0.940237389
Coal	4210	$/GWh(fuel)	15625	23478		OD_Asia	NO	1327	13.78174466	2987	9064		0.01039	0.961756893
Gas	6560	$/GWh(fuel)	34129	44368		ME_NA	NO	470	4.772031962	1194	6432		0.01015	0.940237389
Bio1	43000	$/GWh(fuel)				SSA	NO	450	5.00515703	1194	8772		0.01112	1.03
BioCCS	43000	$/GWh(fuel)												
Waste	27000	$/GWh(fuel)				GLOBAL		14446.3	310.7302911	29348.7	66687.9			
Uranium	4400	$/GWh(fuel)												
Dev_local_factor_MASTER	0.7											CO2 Target	156	MtCO2e
OECD_local_factor_MASTER	1											Reducion fac	0.010798613	
Use_Master_LifeTime	YES	Yes or No												
												LCS Key Results		
OUTPUT DATA							LCS GHG Acheved	GHG Target				Em Factor	COE	
							Mte CO2e	Met?				kgCO2/kWh	£/kWh	
LCS Extra Investment	33391248.31	Million US$				United_Kingdom	126.2	YES				0.3981	0.0252	
						Eastern_Europe	-0.4	YES				-0.0001	0.1202	
						North_America	0.7	YES				0.0001	0.1143	
						Latin_America	-0.2	YES				-0.0001	0.1392	
GHG Emissions	231.232605	Mte CO2				China	104.9	50.12261508				0.0064	0.1105	
GHG Saving (CO2e)	14215.0674	Mte CO2				India	0.0	YES				0.0000	0.1011	
Error on target	-79.49768614	Mte CO2				Asia_Oceania	-0.6	YES				-0.0002	0.0904	
						OD_Asia	0.3	YES				0.0000	0.1192	
						ME_NA	0.2	YES				0.0000	0.1153	
% GHG DECREASE	98.4					SSA	0.1	YES				0.0000	0.1156	
PERCENT INCR COE	49.184					GLOBAL	231.2					0.0035	0.1129	

A3: United Kingdom_output _sheet: Least-cost generation mix

INCREASE OR DECREASE OUTPUT RESULTS					**Action**				
Remaining Demand		-0.197814941	TWh		Capacity Addition				
Additional Investment		1.87326E+11	USD						
Additional Emissions		61.84407425	Mt						
Technology mix in GW		Total	Change in	TWh		LFs		**Installed Capacity**	
		Installed (GW)	Generation (TWh)	Generation				New Share	OldSHare
	Wind Onshore	8.846571922	13	14.65842819		0.189021378		0.250670168	0.027096774
	Wind Offshore	25.44511032	63	65.57979584		0.294011458		0.720994543	0.00516129
	Pumped Storage	1	0	1.263569236		0.144144334		0.028335289	0.03483871
	Solar PV	1	0	0.675655544		0.077076836		0.028335289	
	Hydro	1.385395646	1	3.597309828		0.296211939		0.039255585	
	Nuclear	9.912277222	50	55.61590576		0.640065042		0.280867235	
	Biomass	1	0	4.211862087		0.48047708		0.028335289	
	BECCS	1	0	5.966872215		0.680683575		0.028335289	
	Interconnectors	7.844624996	21	24.07120132		0.350045188		0.222279713	
	Gas CCGT	29.99462891	122	126.2118607		0.480015443		0.849906465	
	Coal CCS	1	0	5.966872215		0.680683575		0.028335289	
	Gas CCGT CCS	4.858489513	23	28.96687317		0.680140884		0.137666702	
	Wave	1	0	1.719873071		0.19619816		0.028335289	
	Tidal	1	0	1.474174738		0.168169603		0.028335289	
	Conventional CHP	1	0	2.105931044		0.24023854		0.028335289	
	Renewable CHP	1	0	2.105931044		0.24023854		0.028335289	
		97.28709853		344.192116					
TECH SWAPPING RESULTS		USED							
Achieved Emissions		34.38526917	MT						
Total Investment		2.43652E+11	USD						
Emissions Change		-28.63299561	Mte						
Technology mix in GW		Total	Change in	TWh					
		Installed (GW)	Generation (TWh)	Generation					
	Wind Onshore	11.26090145	4	18.65842819					
	Wind Offshore	31.26537514	15	80.57979584	19.9227169				
	Solar Thermal	1.792202234	1	2.263569355					
	Solar PV	17.29673004	11	11.67565536					
	Hydro	1.385395646	0	3.597309828					
	Nuclear	9.912277222	0	55.61590576					
	Biomass	2.188303232	5	9.211862564					
	BECCS	2.17432332	7	12.96687222					
	Interconnectors	7.844624996	0	24.07120132					
	Gas CCGT	18.11156082	-50	76.21186066					
	Coal CCS	1	0	5.966872215					
	Gas CCGT CCS	4.858489513	0	28.96687317					
	Wave	2.746078491	3	4.719872952					
	Tidal	3.716121674	4	5.4741745					
	Conventional CHP	1	0	2.105931044					
	Renewable CHP	1	0	2.105931044					
FINAL RESULTS					22.63945103				
					40.75101185				
Annual Emissions		34.38526917	MTeCO2e						
Cap Invest Over LMS		1.28604E+11	USD						

A4: United Kingdom_Output_Sheet; Optimal low-carbon generation mix

Technology mix

Energy Technology	Total Installed (GW)	Generation per year (TWh)	Fuel Energy (TWh) Consumed per yr	Fuel cost per year US$	OPEX Per Year US$
Wind Onshore	11.3	18.7	18.65842819	0	84470273.97
Wind Offshore	31.3	80.6	80.57979584	0	570480540.9
Pumped Storage	1.8	2.3	2.263569355	0	2105479.185
Solar PV	17.3	11.7	11.67565536	0	35077768.52
Hydro	1.4	3.6	3.597309828	0	12389454.72
Nuclear	9.9	55.6	168.5330478	1348264382	92167287.64
Biomass	2.2	9.2	35.29449258	822088295.5	33244702.7
BECCS	2.2	13.0	34.57832591	805407159.2	28650832.26
Interconnectors	7.8	24.1	54.70727574	0	82058019.82
Gas CCGT	18.1	76.2	119.0810323	5896785069	41191122.78
Coal CCS	1.0	6.0	17.81155885	1182528451	10181912
Gas CCGT CCS	4.9	29.0	57.02140388	436139383.7	19289111.91
Wave	2.7	4.7	4.719872952	0	54523388.44
Tidal	3.7	5.5	5.4741745	0	14307068.44
Conventional CHP	1.0	2.1	5.484195426	271572399.8	4696344
Renewable CHP	1.0	2.1	7.019770145	163506271.1	32467200
TOTALS	117.5523838	344.192116	626.4999086	10926291411	1117300507

Cost of Energy Calculation					Misc Data	
LMS Investment	98762157420	*LMSInvestCell*	United_Kingdom_in!LMS_Investment		Fuel Energy Used	
HMS_CAPEX	2.27366E+11				Biomass	Biomass_Used_CCS
						Biomass_Used_Unabated
HMS_Ongoing	12043591918				Coal	Coal_Used_CCS
						Coal_Used_Unabated
HMS_COE	0.105064534				Gas	Gas_Used_CCS
						Gas_Used_Unabated