Integrated Decarbonisation Strategies for the Electricity, Heat, and Transport Sectors

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by

Peng Fu

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Department of Electrical and Electronic Engineering

Imperial College London

Declaration

I declare that the contents of this thesis are my own work. No part of the work referred to in this thesis has been presented to support an application for another degree or qualification in this or any other Universities. Any ideas or quotations from other work are appropriately referenced.

Peng Fu

March 2021

Dedication

This thesis is dedicated to my father and my mother, Erjun Fu and Jurong He, for their unconditional love and support. My father is the bravest man I have ever known, and I have faith that he can beat cancer and has a healthy future.

Acknowledgements

This thesis is dedicated to my father and my mother, Erjun Fu and Jurong He. My father struggles with cancer for four years throughout my PhD studies while hiding his condition from me. In the past year, I have accompanied my father through unbearable pain in his fight against cancer, and this PhD thesis is completed with the encouragement and support of my father at the hospital. My mother takes on my father's cancer treatment all by herself and looks after him while I am away from home. She suffers tremendous stress and pain, and I must express my deepest gratitude to my mother.

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Abstract

The rapid climate change experienced at the beginning of the twenty-first century is intimately entwined with the increase in anthropogenic greenhouse gas (GHG) emissions resulting from the growth of fossil fuel consumption in all energy sectors. By 2050, not only these energy sectors must eliminate GHG emissions: electricity, heat, transport, but also those sectors should be closely coupled to achieve maximum synergy effects and efficiency. In this context, this thesis develops integrated models to assess decarbonisation strategies for a variety of complex energy system transitions, including the electricity, heat and transport sectors.

Firstly, the thesis proposes a novel single-year, integrated electricity, heat and transport sectors model that considers integrating the hydrogen supply chain while optimising the system's investment and operation costs and covers both local and national levels. A series of studies are then carried out to evaluate different integrated decarbonisation strategies for the future low-carbon energy system based on the single-year integrated multi-energy optimisation model.

Secondly, this thesis evaluates the economic performance and system implications of different road-transport decarbonisation strategies and analyses the electricity sector decarbonisation synergy. Great Britain (GB) case study suggests that transport electrification should be carried out with smart charging to reduce the additional cost on the electricity sector expansion. Hydrogen fuel cell vehicle (HFCV) can be combined with electric vehicle (EV) to reduce the system of increased peak demand due to road transport's electrification. However, when EV enables smart charging, the case for HFCV becomes less compelling from a system perspective. Their penetration is limited by their higher capital costs and lower efficiency compared to EV. The results also clearly demonstrate a synergy between the hydrogen used in the electricity and

transport sector. The integration of hydrogen-fuelled generation can reduce the overall system cost by enabling more investment in renewable energy and reduce the need for the firm but high-cost low-carbon generation technologies, particularly nuclear and gas with carbon capture and storage (CCS). The integration of power-to-gas (P2G) facilities can increase the integration of wind power capacity.

Additionally, the heat sector's decarbonisation is one of the key challenges in achieving the net-zero target by 2050. This thesis evaluates the integrated decarbonisation strategies for the electricity, heat and transport sectors involving hydrogen integration. A study compares the economic advantages under the deployments of P2G hydrogen production and gas-to-gas (G2G) hydrogen production and the associated implications for overall system planning and operation. The results demonstrate that hydrogen integration through the G2G process brings more economic benefits than the P2G process; combining P2G with G2G can yield further cost savings. The results also clearly show the changes in the electricity side driven by the different hydrogen integration strategies. The integration of hydrogen will promote hydrogen boiler (HB) deployment, which will dominate the heating market, combined with the heat pump (HP). From the perspective of the transport sector, the development of HFCV is positively related to the integration cost of the hydrogen system, especially in the demanding carbon scenario.

Going further, the single-year, multi-energy integrated optimisation model has limitations, focusing only on short-term investment operations and unable to deal with the long-term system planning problem. Therefore, this thesis presents a novel transition model for the electricity, heat and transport sectors, operating in full hourly resolution and taking into account sectoral coupling, simulating future energy systems' transition to low-carbon energy production.

Finally, considering the different difficulties and speeds of transition in the different energy sectors and the complementary effects between energy sectors, designing individual sector transition cannot provide a systematic view, as the most valuable sector coupling effects are overlooked, and sector separation consideration underestimates the complexity of the optimal transition pathway. This thesis designs three integrated energy system transition pathways based on the multi-year transition model, placing sector coupling and considering a full range of low-carbon technologies, enabling fundamental insights into the optimal energy system transition pathway to achieve the net-zero target by 2050. The GB case study results demonstrate that electrification combined with hydrogen integration will be the most cost-effective pathway. Hybrid heating technologies and EV will be the leading options in the heat and transport sector for decarbonisation. Bioenergy will play an essential role to offset carbon emissions from the other energy sectors. Cross-energy flexibility is vital to achieving a cost-effective transition pathway. Based on the above results, the policy recommendations for the net-zero target achieving can be made for policymakers.

Nomenclature

Abbreviations

ATR	Autothermal reformer
BECCS	Bioenergy-fuelled power plants with CCS
BECHPCCS	Bioenergy-fuelled combined heat and power plants
BHCCS	Biomass-derived hydrogen production with CCS
BES	Electricity bulk storage
CCGT	Combined cycle gas turbines
CCS	Carbon capture and storage
CHP	Combined heat and power
CTES	Centralised TES
COP	Coefficient of performance
DAC	Direct air capture
DHN	District heating network
DSR	Demand-side response
DTES	End-use TES
DES	Electricity distributed storage
EES	Electricity energy storage
EL	Electrolyser
EV	Electric vehicle
FV	Fossil fuel vehicles
GB	Great Britain
GHG	Greenhouse gas
G2G	Gas-to-gas

HFCV	Hydrogen fuel cell vehicle
HP	End-use heat pump
HB	End-use hydrogen boiler
HP-B	Hybrid heat pump and natural gas boiler
HP-HB	Hybrid heat pump and hydrogen boiler
EES	Electricity energy storage
GB	Great Britain
GHR	Gas heated reformer
INGB	Industrial natural gas boiler
IHP	Industrial heat pump
IHB	Industrial hydrogen boiler
H2S	Hydrogen storage
MES	Multi-energy systems
MSW	Municipal solid waste
MILP	Mixed-integer linear programming
NET	Negative emissions technology
NGB	End-use Natural gas boiler
OCGT	Open cycle gas turbines
O&M	Operations & maintenance
PV	Photovoltaics
P2G	Power-to-gas
RES	Renewable energy sources
SMR	Steam methane reforming
TES	Thermal energy storage
UK	United Kingdom

Indices and Sets

$i \in I$	Index and set of locations
$r \in R$	Index and set of regions
$y \in Y$	Index and set of planning and operation horizons
$t \in T$	Index and set of operating time intervals
$d \in D$	Index and set of operating days
$g \in G$	Index and set of electricity generation
$l \in L$	Index and set of transmission/interconnection corridors
$b \in B$	Index and set of biomass raw material

Parameters

DE	Electricity demand [GW]
DH	Heat demand [GW]
DT	Transport demand [GW]
c	The capital cost of technology [£/GW/year]
o	The operation cost of each sector [£/GWh]
nl	Generation no-load cost [£/h]
su	Generation start-up cost [£/start]
$\overline{P}$	The power rating of a generation unit [GW]
$\underline{P}$	Minimum stable generation of a generation unit [GW]
R^u	Ramping up limit [GW/h]
R^d	Ramping down limit [GW/h]
$\underline{up}$	Minimum up time [h]
$\underline{down}$	Minimum down time [h]

$\overline{rsp}$	Frequency response limit [GW]
$\overline{res}$	Spinning reserve limit [GW]
$\overline{SF}$	System frequency response requirement [GW]
$\overline{SR}$	System operation reserve requirement [GW]
af	Annual availability factor of generation [%]
nb	The upper limit of the annual newly built capacity of technologies [GW]
Z	Conversion rate from electricity to heat for CHP
γ	The maximum ratio of heat to electricity for CHP
α	Percentage of storage charging for frequency response
est	Number of hours storage can produce energy at maximum power [h]
$\overline{dac}$	The capacity of the DAC plant [t/year]
η	Energy conversion efficiency [%]
τ	Vehicle fuel consumption [kWh/km]
ε	The ratio of flexible transport demand [%]
ξ	The ratio of electricity demand at high-voltage distribution level [%]
σ	Reverse power flow coefficient [%]
lt	The lifetime of technology [Years]
β	Discount rate [%]
CT	Carbon target [t or g/kWh]
ce	Carbon emission of each technology [tCO_2/GWh]
ω	Change of carbon emission percentage [%]
BA	Maximum virgin biomass crop yield of raw material [t/hectare/year]

LA	Maximum biomass land availability [hectare]
BC	Virgin biomass raw material cost [£/t]
PC	Annualised pellet capital cost [£/t]
PO	Pellet operation cost [£/t]
CC	The carbon content of biomass pellet [%]
CCR	Carbon capture rate [%]

Variables

TC	Total cost [£]
$CAPEX$	Total capital cost [£]
$OPEX$	Total operating cost [£]
$\overline{n}$	The existing capacity of technologies [GW]
n	The additional capacity of technologies [GW]
nh	The number of households
$\overline{nh}$	The number of new households to install the heating technologies
$\overline{nc}$	The number of new vehicles
nc	The number of vehicles
f	Energy flow [GW]
P	Electricity generation [GW]
st	Number of generating units being synchronised
dst	Number of generating units being de-synchronised
μ	Number of units in operation
rsp	Frequency response [GW]
res	Spinning reserve [GW]
H	Heating production [GW]

V	Transportation supply [GW]
dac	Direct air capture rate [t/h]
dsr^-	Reduction in transport load due to DSR [GW]
dsr^+	Increased transport load due to DSR [GW]
Q	Hydrogen production [GW]
S^+	Discharging rate of energy storage [GW]
S^-	Charging rate of energy storage [GW]
SC	The energy content of hydrogen storage [GWh]
λ	Penetration of production technologies [%]
TB	Total annual virgin biomass crop yield of raw material [t/year]
PT	Pellet cost [£/t]
TP	Total annual biomass pellet availability [t/year]
BP	Demand for biomass pellet [t/h]
CA	Carbon emission [t].

Superscripts

e	Electricity sector infrastructure related
h	Heat sector infrastructure related
hn	District heating infrastructure related
dhn	District heating network related
ed	End-use heating technologies related
v	Transport sector infrastructure related
$h2$	Hydrogen sector infrastructure related
hv	High-voltage distribution network related
lv	Low-voltage distribution network related

chp	Combined heat and power generation related
hp	Industrial heat pump related
ehp	End-use heat pump related
ngb	Industrial natural gas boiler related
$engb$	End-use natural gas boiler related
hb	Industrial hydrogen boiler related
ehb	End-use hydrogen boiler related
hy	Hybrid heating technologies related
el	Electrolyser related
ghr	Gas heated reformer related
hs	Hydrogen storage related
ht	Hydrogen transmission pipeline related
be	Bioenergy-fuelled power plants with CCS related
$bechp$	Bioenergy-fuelled combined heat and power plants with CCS related
bh	Biomass-derived hydrogen production with CCS related
fv	Fossil fuel vehicle related
ev	Electric vehicle related
$hfcv$	Hydrogen fuel cell vehicle related
en	Electricity network related
es	Energy storage related
bes	Electricity bulk storage related
des	Electricity distributed storage related
$hves$	High-voltage electricity distributed storage related
$lves$	Low-voltage electricity distributed storage related
$ctes$	Centralised thermal energy storage related

$etes$	End-use thermal energy storage related
dac	Direct air capture related
de	Decommissioned capacity related
dsr	Demand-side response related
bio	Biomass supply chain related

List of Publications

Journal Papers

P. Fu, D. Pudjianto, X. Zhang, and G. Strbac, "Integration of Hydrogen into Multi-Energy Systems Optimisation," *Energies,* vol. 13, no. 7, p. 1606, 2020.

P. Fu, D. Pudjianto, and G. Strbac, "Integration of power-to-gas and low-carbon road transport in Great Britain's future energy system," *IET Renewable Power Generation,* 2021.

P. Fu, D. Pudjianto, and G. Strbac, "A Long-term Multi-Regional, Multi-Energy Systems Planning Towards the future Low-Carbon Energy System of Great Britain," *Renewable & Sustainable Energy Reviews,* submitted for publication.

Conference Papers

P. Fu, D. Pudjianto, X. Zhang, and G. Strbac, "Evaluating strategies for decarbonising the transport sector in Great Britain," in *2019 IEEE Milan PowerTech*, 2019, pp. 1-6: IEEE.

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Chapter 1. Introduction

1.1. Background

The increasing anthropogenic GHG emissions are one of the greatest threats to human civilisation. The impact of climate change extends far beyond the rise in temperature and sea level. It also has significant implications for water, energy, transport, wildlife, agriculture, ecosystems and human health [1]. In recent years, these climate change effects are accelerating, climate-related disasters pile up season after season. As a response, society and government are showing renewed interest in climate change mitigation. The Paris Agreement, the first-ever universal and legally binding global climate change agreement, sets out a global framework to avoid dangerous climate change by limiting global warming to well below 2°C [2]. A growing number of regions and countries have set targets to limit GHG emissions further or have developed transition pathways to a low-carbon energy system in the coming decades [3]. In 2019, the United Kingdom (UK) became the first major economy to pass net-zero emissions law [4]. Comparing to the Climate Change Act, passed in 2008, which committed to reducing GHG by at least 80% in 2050 from 1990 levels [5]. The net-zero emissions law sets a new ambitious environmental target of achieving net-zero for all GHG emissions by 2050.

The electricity sector (i.e., from power stations and other energy supply), the heat sector (i.e., residential sector), and the transport sector (excluding emissions from international aviation and shipping, but including domestic aviation (i.e., flights taking off and landing within the UK) and shipping) are the major sources of GHG emissions in the UK, responsible for about 63% (274.9 $MtCO_2e$) of all GHG emissions (435.2 $MtCO_2e$) in 2019. The rest of GHG emissions come mainly from business, public, agriculture, industrial process, waste management, land use, land use change and forestry and other GHG, which cannot be derived based on energy statistics [6]. All three sectors (i.e., electricity, heat, and transport sectors) require equal attention to achieve the net-zero target by 2050.

Electricity consumption in lower-income yet fast-growing economies is still small but is expected to increase significantly. These countries are likely to emerge as key centres of energy consumption. These lower-income countries are facing the dual challenge of fuelling their economic growth while producing and consuming energy more sustainably. The transition towards a sustainable energy system is indispensable to the low to their economic growth, which demands radical changes in the structure of the electricity system [7]. The electricity sector emissions are almost all carbon emissions [8], from burning fossil fuels like coal and natural gas for electricity generation. The UK electricity sector contributed 21% (90.1 $MtCO_2e$) of UK total emissions in 2019, 63% lower than in 1990 [6]. This decrease has mainly resulted from the rapid growth of renewable energy sources (RES) generation, combining with nuclear and other alternative forms of low-carbon generation. In 2019, around 54% of UK electricity generation came from low-carbon sources, and 37% of UK electricity generation from renewables and 20% of UK electricity generation from wind power. A record-low 43% was from fossil fuels, with 41% from gas and just 2% from coal [9]. However, the decarbonisation of heat and transport sectors through electrification will increase electricity demand and the required energy infrastructure capacity. Therefore, the future energy system should be planned carefully to consider the sectoral coupling and synergies between the electricity, heat, and transport sectors. Further decarbonisation in the electricity sector requires the continued deployment of RES and other low-carbon electricity generation and improving energy efficiency or reducing the need for electrification of other energy sectors using alternative energy forms such as hydrogen and bioenergy.

More than half of the end-user energy consumption is used to provide heat in the UK [10]. Therefore, the decarbonisation of the heating sector is a vital part of achieving the net-zero target. In 2019, the heat sector emitted 65.2 $MtCO_2e$, accounting for 15% of total GHG emissions, which only fall 17% compared to 1990. The relatively small GHG reduction from the heat sector reflects the tremendous potential for decarbonising the heat sector through a mixture of low-carbon heating measures. Currently, around 80% of the UK's heat demand is met by natural gas, with most of the remainder from electricity [11]. Heat demand is much more variable across the year, and its peak demand is also much higher than peak non-heat electricity demand. Meeting heat demand fully by electricity would impose enormous strains on the electricity grid. Therefore, various low-carbon heating technologies such as district heating, HP and HB should be optimally deployed to decarbonise the heat sector.

In 2019, the transport sector contributed the largest part of GHG emissions (119.6 MtCO2e), accounting for 27% of all GHG emissions; this is a decrease of only 5% compared to 1990 [6]. However, with the development of zero-emission technologies across road transport such as EV and HFCV, their cost is becoming cost-effective. More priority actions and policies are being taken to accelerate the transition to decarbonise the transport sector. The UK government published its Road to Zero Strategy [12] in 2018, which set a target for at least 50%, and potentially as many as 70% of new car sales to be EVs by 2030. In 2019, the UK government ban on new petrol and diesel cars in the UK from 2030 [13]. The UK H2 Mobility project is established to evaluate the benefits of HFCV to the UK and develop a roadmap to decarbonise road transport and hydrogen refuelling infrastructure [14]. All these actions and policies will encourage the rapid decarbonisation of the transport sector. There are some obstacles to the large-scale deployment of EVs, such as higher upfront costs and the expansion of the electricity sector due to larger-scale EV integrations. As a strong complement to electrification, hydrogen can be used selectively, alongside widespread electrification and has potential value as a zero-emission option for transport sector [15], but this option rely on the possibility of producing hydrogen by a low-carbon route and storing it at scale.

The electrification and other energy forms' integration leads to sector coupling. Different sectors' transition should consider the interactions between the sectors and proceed optimally to avoid uncoordinated independent investments and maximise synergies. Accordingly, the concept of multi-energy systems (MES) is receiving considerable attention, whereby electricity, heat, and transport sectors optimally interact with each other. MES represents an approach to provide the much-required sector-coupling flexibility to support the cost-effective transition to the low-carbon energy future. The flexibility can be improved by shifting supply and demand across energy sectors using different energy storage technologies [16]. In this context, the planning and operation of MES should be conducted using a holistic whole-system approach, where the interactions across technologies, different system components from the supply side, energy networks, energy storage, temporal intertwined between operational decisions (e.g., load-shifting), energy exchange and capacity sharing across different regions are considered. The whole-system planning approach can enable synergies between energy sectors to be realised, and conflicts avoided [17], and evaluate different integrated decarbonisation strategies for the whole energy system. Lack of coordination across energy vectors will lead to suboptimal system development.

1.2. Research Questions

This thesis focuses on proposing and developing MES investment and operation models to evaluate the various integrated decarbonisation strategies for electricity, heat and transport sectors from short-term and long-term perspectives to deliver the future low-carbon energy system. The main research questions of this PhD thesis can be summarised as:

RQ1: How to evaluate the different strategies for decarbonising the integrated electricity and transport sectors in Great Britain?

Electrification and a shift from fossil fuel to hydrogen are two main options for decarbonising the transport sector. The potentially valuable cross-sector impacts should be considered in the whole system modelling to economically identify the optimal transition of integrated electricity and transport sectors.

The electrification option will inevitably lead to electricity generation and electricity networks' capacity to satisfy the increasing demand. The hydrogen shift option needs to build a comprehensive hydrogen supply chain from hydrogen production, transmission, distribution to storage. How to quantify the whole system investment and operational costs driven by different transport sector decarbonisation strategies and what the optimal transition pathway is for the integration of the electricity and transport sectors remain to be an open question.

RQ2: What is the role and impact of power-to-gas (P2G) integration in the integrated electricity and transport sectors?

P2G is a technology that uses electrical power to produce a gaseous fuel, and most P2G systems use electrolysis to produce hydrogen. It has been treated as a low-carbon method to produce clear fuel for the electricity, heat and transport sector. In addition to producing hydrogen, it can also support the electricity sector by modulating its electricity consumption profile, thus offering a fast response to maintain network frequency. In the context of MES, the electricity sector and electromobility are expected to interweave more and more, leading to a new structure of the overall MES. As a valid energy conversion option, P2G recovers excess renewable energy to produce carbon-neutral hydrogen.

Most of the previous literature has investigated the impact of P2G on the electricity sector. The deployment of different fleets, such as EV and HFCV, has also been thoroughly investigated in other studies. However, the role and impact of P2G in the transition of the low-carbon transport sector and the sectoral coupling synergies between the electricity and transport sectors need to be investigated.

RQ3: What are the benefits and implications of integrating different hydrogen production technologies into integrated electricity, heat and transport sectors?

In 2019, the heating sector contributed around 15% of the UK's greenhouse gas emissions, with carbon dioxide being the most prominent gas in this sector (96%). In order to achieve the required net-zero emissions by 2050, alternatives to carbon-based fuels will be needed throughout the energy system, not only in the electricity sector but also in the heat and transport sectors. As a clean fuel, hydrogen can deliver competitive low-carbon solutions across a wide range of applications.

However, as a strong complement to electrification, the possibility of larger-scale hydrogen integration relies on the cost-effective investment in hydrogen infrastructure, policy alignment and demand creation. The main concerns for hydrogen production are where the larger volumes of hydrogen will come from and how to establish a low-carbon and renewable hydrogen production route. The optimal plan and operation of integrated electricity, heat and transport sectors combined with large-scale hydrogen integration have yet to be investigated on the local and national levels. Besides, different hydrogen production technologies enable interactions among electricity, heat and transport sectors. The sector coupling is beneficial for the whole system, and fuel synthesis provides additional cross-sector flexibility to the energy system. How to assess the values and cross-sector impacts bring by hydrogen integration become a key question.

RQ4: How to design the transition pathways for future energy systems in the context of MES to achieve the net-zero target by 2050?

In order to address the long-term investment plan and operation of integrated electricity, heat, and transport sectors, including national and local levels infrastructure, cost-effectively, it is imperative to assess the strengths and weaknesses of different decarbonisation strategies and to determine the optimal design of the proposed MES, thus achieving sectors closely coupled and maximising synergies and efficiency.

The design of transition pathways for future energy system in the context of MES needs to consider the uncertainties of fossil fuels price and technologies costs and the different regional dynamics and characteristics. In order to capture the dynamic characteristics of the transition process in the different energy sectors, a comprehensive multi-year transition model cast over one or more decades, attempting to encapsulate the structural evolution of the system and are used to investigate capacity expansion and energy system transition issues would be essential.

1.3. Original Contributions

This PhD thesis's original contributions are associated with developing new whole-system optimisation models and comprehensive analyses of various future development scenarios to assess different integrated decarbonisation strategies of the electricity, heat, and transport sectors to achieve the required carbon emissions targets. The original contributions of this PhD thesis can be summarised as follows:

- Develop a single-year integrated electricity, heat, and transport systems modelling framework considering spatial-temporal and technical detail of all technologies at both national and local levels based on the whole electricity system model proposed in [18]. The modelling of the heat sector is referred to [19]. For the first time, the proposed model considers the transport sector and hydrogen integration, which simultaneously considers the infrastructure capital expenditures and whole system operative expenditures, thus meeting the specific carbon targets at a lower whole system cost.

- Analyse different decarbonisation strategies based on electrification and hydrogen use for the integrated electricity and transport sectors, demonstrating the deployment of different road-transport technologies across the national scale and the strong interaction between the electricity and transport sectors.
- Identify the opportunities to integrate P2G into different energy sectors with various uses. Two potential clean fuels in the future transport sector, i.e., electromobility and hydrogen-based mobility, are investigated to evaluate their combined P2G integration behaviour. It provides a better understanding of the commercial and investment implications for deploying the P2G facility and zero-emission vehicles to achieve specific carbon targets.
- Assess the system implications, economic, and environmental impacts of different hydrogen production infrastructures across the whole system level. Meanwhile, investigate the implications of hydrogen integration on each energy sector under different carbon targets, exploring interactions among the electricity, heat and transport sectors.
- Develop a multi-year MES transition model to address future energy supply pathways where cost and carbon targets are the priorities. For the first time, the proposed framework considers the long-term energy infrastructures expansion planning and short-term system operation accounting for key technical constraints in electricity, heat and transport sectors, as well as the supply chains of hydrogen and biomass utilisation. This thesis provides a flexible and comprehensive modelling framework and full insight into the long-term energy roadmap composition at both national and local levels.
- Design and evaluate three transition pathways for the GB's future energy system to achieve the net-zero carbon target by 2050. Conduct a comprehensive set of case studies to demonstrate the economic performance and driving factors of each pathway.

Also, placing sector coupling into the optimal energy system transition pathway and discussing each energy sector's transition process.

1.4. Thesis Structure

This thesis consists of eight chapters to address the proposed research questions, which are summarised as follows:

Chapter 2 introduces the fundamental structure of the proposed models in this thesis. The technical components in each energy sector and other energy infrastructures considered in this thesis are introduced. The potential interactions among different energy sectors and technologies are demonstrated in this chapter, and the following chapters adopt this structure to assess different strategies with different technologies combinations.

Chapter 3 proposes a novel mixed-integer linear programming (MILP) modelling framework for the single-year MES optimisation, considering the investment and operation of electricity, heat, transport sectors and hydrogen integration at both national and local levels. The proposed modelling framework is flexible, which can evaluate different decarbonisation strategies for different energy sectors. The MILP problem defined in this chapter is implemented in the FICO® Xpress optimisation tool [20].

Chapter 4 evaluates two strategies to decarbonise the integrated electricity and transport sectors. The first strategy assumes that all transportation fleets will be electrified. The importance of flexibility that EV can potentially provide is also assessed. The second strategy assumes all vehicles will be fuelled by hydrogen. The synergy between electricity and hydrogen system is analysed. A range of case studies on future GB development scenarios is carried out to demonstrate the model's suitability to assess different decarbonisation strategies' economic performance and energy system implications.

Chapter 5 is an extension of Chapter 4, which assesses the economic performance and systemic impacts of different road transport decarbonisation strategies, and analyses synergies with P2G and the electricity sector decarbonisation. The case studies demonstrate the importance of integrating road transport and P2G into GB's future energy system.

Chapter 6 investigates the role of hydrogen in decarbonisation for various energy sectors, which considers two hydrogen production processes: 1). G2G with CCS, and 2). P2G. The advantages and disadvantages of different hydrogen production technologies and the cross-sector benefits are demonstrated based on a future GB energy system.

Chapter 7 extends the single-year model proposed in Chapter 3 to the multi-year MES optimisation model. This chapter's proposed model includes electricity, heat and transport sectors, and hydrogen and NETs integration. It allows for the simultaneous optimisation of energy infrastructure expansion over different periods, taking into account the dynamics of costs, fuel prices and carbon targets and considering the technical lifetimes and decommissioning plans of different technologies in the different energy sectors. The MILP problem defined in this chapter is implemented in the FICO® Xpress optimisation tool [20].

Chapter 8 investigates multiple decarbonisation pathways for the net-zero carbon target using the proposed model in Chapter 7. Three transition pathways are identified: 1). by integrating hydrogen, shifting the energy consumption in electricity, heat and transport sectors to low-carbon hydrogen; 2). by electrification of heat and transport sectors supported by low-carbon electricity generation; 3). by potential hybrid solutions, the hydrogen integration and penetration level of electrification should be optimised. This chapter focus on optimising long-term decarbonisation strategies for the future GB energy system. The cost performance of each decarbonisation pathway and cross-cutting analysis across different energy sectors are demonstrated.

Chapter 9 summarises the main conclusions of this PhD thesis and identifies possible directions for future research.

Chapter 2. Modelling Framework and Key Assumptions

2.1. Introduction

The MES considered in this thesis has the primary objective of supplying electricity, heat, and transport demand, consisting of two energy supply chains: hydrogen and biomass and electricity, heat, transport sectors. Each supply chain and energy sector includes the possible existence of energy supply infrastructure, various conversion technologies and storage units.

The technologies considered in this model can be classified into five main categories: 1). hydrogen supply chain; 2). negative emissions technologies (NETs) deployment; 3). electricity sector; 4). heat sector; 5). transport sector. This chapter describes the detailed components of the supply chain and each energy sector.

Chapter 2 is organised as follows: Section 2.2 presents the hydrogen supply chain from its production, transmission, distribution to storage. Section 2.3 describes the NETs includes the biomass utilisation supply chain and the direct air capture (DAC) technology. Section 2.4 presents the electricity sector components, consisting of electricity generation, transmission, distribution and electricity energy storage (EES). Section 2.5 presents various low-carbon heating technologies and thermal energy storage (TES). Section 2.6 describe two zero-emission vehicles, which are EV and HFCV. Finally, Section 2.7 describes the complete modelling framework in this thesis, which presents the possible interactions among various energy sectors.

2.2. Hydrogen Integration Modelling

Hydrogen is an attractive option for decarbonising the existing energy system. It can extend the use of existing natural gas infrastructure, has low-cost energy storability and flexibility, and excess electricity generated from RES can be converted into hydrogen. Hydrogen is already entering the energy sector in stand-alone forms, such as EL and HFCV. However, its widespread use requires a complete supply chain to ensure decarbonisation for various energy sectors. The hydrogen supply chain designed in this thesis, including hydrogen production, transmission, and storage which are further explored as follows:

Hydrogen production: There are several technologies used to produce hydrogen. One low-carbon route for hydrogen production is via the electrolysis of water. Approximately 4% of global hydrogen production is from electrolysis processes [21]. Surplus electricity from RES can also produce hydrogen through the EL, but it will increase the electricity sector's capacity requirement. The EL can take part in the electricity market for operational reserve like load shedding in grid incidents. For example, alkaline EL can change its electricity consumption in the range of 15%-120% of its nominal power within one second [22]. This feature makes it attractive for coupling with RES generation and capable to provide a fast response to offer ancillary services [23].

Electrolysis of water dissociates hydrogen and oxygen through electrolysis cell using electricity. The general cell consists of an anode, cathode, electrolyte and membrane. There are three main types of EL: alkaline, proton exchange membrane and solid oxide EL. The alkaline EL is widely recognised as a mature technology and accounts for most of the installed water electrolysis capacity worldwide. Therefore, alkaline is used in the hydrogen supply chain in this thesis. The alkaline electrolysis cell works by applying direct current voltage, decomposes water molecules, and the diaphragm passes hydroxide ions from the cathode to the anode. Hydrogen is formed at the cathode and oxygen at the anode [24]. The chemical reactions take place in alkaline EL at the cathode, and the anode are given as (2.1) and (2.2) [25].

$$2H_2O + 2e^- \rightarrow H_2(g) + 2OH^- \tag{2.1}$$

$$2OH^-(aq.) \rightarrow \frac{1}{2}O_2(g) + H_2O(l) + 2e^- \tag{2.2}$$

Currently, the majority of hydrogen will be produced from natural gas by the steam methane reforming plant and associated CCS (SMR-CCS) infrastructure due to its economic advantages. The core of the process is the reaction of methane with steam at high temperatures to produce hydrogen and carbon monoxide (2.3). Another reaction, namely water-gas shift, reacts the produced carbon monoxide with steam to produce more hydrogen but produces carbon dioxide (2.4) [26].

$$CH_4 + H_2O \rightarrow CO + 3H_2 \tag{2.3}$$

$$CO + H_2O \rightarrow CO_2 + H_2 \tag{2.4}$$

This method's primary concerns and challenges are decarbonising it when large volumes of hydrogen are produced. Therefore, a low-carbon hydrogen technology that offers efficiency benefits by coupling a gas-heated reformer (GHR) with an autothermal reformer (ATR) is considered.

GHR is where the reforming occurs in a tubular heat exchanger where the heat for reaction comes from another gas stream. The ATR technology needs the air separation unit, which consumes additional electricity demand. Using electricity sourced from RES instead of steam raising can dramatically reduce carbon emission with lower natural gas consumption if a portion of the hydrogen produced is used as the fuel to meet the plant's electricity demand. The carbon dioxide capture rate can reach 95% with ATR technology, higher than the 90% maximum for SMR technology. The high capture rate of carbon dioxide of GHR-ATR makes it more attractive for low-carbon hydrogen production.

Besides the above two hydrogen production technologies, there is a growing interest in biomass-fuelled hydrogen production, which can produce hydrogen and remove carbon dioxide from the atmosphere. This thesis adopts biomass gasification, which is a thermochemical pathway that converts biomass into a gaseous fuel mixture, including hydrogen by pyrolysis and gasification.

Hydrogen transmission and distribution: Currently, the National Transmission System and Local Transmission System in the UK are constructed primarily from carbon steel. The unprotected iron and carbon steel pipelines suffer from embrittlement due to the diffusion of hydrogen into the material, which results in a reduction of structural integrity and can potentially cause a fracture. Therefore, these materials are not suitable for hydrogen networks [27]-[28]. Hydrogen transmission networks are likely to need if hydrogen production is centralised.

Embrittlement is a pressure-driven process and is less of a concern at lower pressures [29]. The UK's existing low-pressure and medium-pressure gas network is currently in reasonable repair and converted to polyethylene pipe via the Government-sponsored Iron Mains Replacement Programme [30]. Polyethylene pipes are suitable for transporting hydrogen at low pressures [31]. Currently, about 70,000 km of the 280,000 km of the low-pressure gas distribution network is made of iron pipes that are not suitable for hydrogen [32]. The rest is made of tolerant polyethylene pipes. By 2030 the Iron Mains Replacement Programme is expected to have replaced a majority of the remaining iron pipes, leaving only a few percentages that will need to be converted to hydrogen tolerant [33].

In this thesis, assuming new hydrogen transmission through pipelines is needed in addition to the existing transmission gas pipelines. At the distribution level, the upgrade of the gas distribution network will occur in all scenarios, assuming the local natural gas distribution systems will be compatible with hydrogen use and the upgrade cost of gas distribution is excluded from the models.

Hydrogen storage: Hydrogen can be served as a storage and transportation medium to manage the balance between inflexible hydrogen production and highly variable hydrogen demand. In general, there are four different ways to store hydrogen [34]: 1). storage of pressurised gas; 2). storage of liquid hydrogen; 3). storage via absorption; 4). storage in chemical compounds. As storage of pressurised gas method, the salt cavern is used in this thesis for hydrogen storage (H2S) with intra-day, daily, weekly, or seasonal operation.

2.3. Negative Emissions Technologies Modelling

Despite the risks and damages of climate change in almost all nations, fossil fuel consumption is growing in all energy sectors [35]. Fossil fuel consumption, agriculture, land-use change, and cement production still dominate the atmosphere's carbon emissions. Removing carbon dioxide from the atmosphere and sequestering it through NETs has the same impact on reducing direct carbon emissions to the atmosphere. NETs have been part of the portfolio to achieve the net-zero target by 2050. Bioenergy with CCS and DAC are two technologies considered in this thesis.

Biomass utilisation supply chain: Deploying biomass-based applications requires the integration of three elements: 1). A biomass utilisation supply chain including biomass production, processing and transport, 2). energy production facilities, including bioenergy-fuelled generation and biomass-derived hydrogen production [36], 3). CCS infrastructure. The raw biomass material collected from farms or waste collection sites is transported to the pellet production plant to be converted into pellets firstly. These pellets are transported to the bioenergy-fuelled energy production plants to generate electricity, heat or hydrogen. It is worth noting the generated carbon dioxide should be captured through CCS and stored in geological formations.

Considering the UK's conditions, six types of raw biomass material are considered in this thesis: miscanthus, poplar, municipal solid waste (MSW), waste wood, forest residue and crop residue. Bioenergy crops such as miscanthus and poplar are suitable for growing in the UK due to sufficient rain and sunshine throughout the year. The availabilities of MSW and waste wood can be treated as a function of population density. Forest residues include the logging residues from harvesting wood and the remaining stumps. The crop residue varies with the cultivated area, types of crops, climate conditions, soil conditions and farming efficiency. In order to meet the environmental and harvesting constraints, crop residue's sustainable removal rates are considered to vary between 30% to 60%. The above six raw biomass material availabilities and distribution in the UK are referred to [37].

Three different bioenergy conversion technologies are considered in this thesis: 1). Bioenergy-fuelled power plants with CCS, which generates electricity only (BECCS), 2). bioenergy-fuelled combined heat and power plants with CCS (BECHPCCS), 3). biomass-derived hydrogen production with CCS (BHCCS).

Direct air capture: As a new and high-tech NET, DAC is receiving significant attention to providing a way to reduce carbon emissions. DAC offers inherent placement flexibility, reducing the need for pipelines from the capture site to the sequestration reservoir [38]. However, doubts remain about the long-term cost and energy requirements of the DAC, which could undermine its expected role in achieving the net-zero target. Current state-of-the-art DAC technologies can be categorised as high-temperature aqueous solutions and low-temperature solid sorbent systems. DAC capital cost and energy demand are estimated in [39], which indicates that DAC system cost could be lowered significantly with commercialisation from 2020 followed by the possibility of large-scale deployment from 2040, making it competitive and affordable for carbon emissions mitigation.

Basic air capture models consist of contacting area, solvent or sorbent and regeneration module. Contacting area exposes sorbent to ambient air and facilitates airflow through the model, increasing the absorption or adsorption of carbon dioxide molecules.

In this thesis, the high-temperature DAC is adopted. The high-temperature DAC solution consists of two cycles which can happen simultaneously. In the first cycle, ambient air is brought into contact with sprayed sodium hydroxide as the solvent. Carbon dioxide reacts with sodium hydroxide and form sodium carbonate (2.5). In the second cycle, sodium carbonate is mixed with calcium hydroxide in the causticiser unit, where solid calcium carbonate is formed, and sodium hydroxide is regenerated (2.6). The formed sodium hydroxide is sent back to the contactor to start another absorption cycle. The solid calcium carbonate is heated up to around 900 °C in the calciner unit to release carbon dioxide and calcium oxide (2.7). Finally, carbon dioxide is captured, and calcium oxide is mixed with water in the slaker unit to form calcium hydroxide and reused in the causticiser process (2.8).

$$2NaOH + CO_2 \rightarrow Na_2CO_3 + H_2O \tag{2.5}$$

$$Na_2CO_3 + Ca(OH)_2 \rightarrow 2NaOH + CaCO_3 \tag{2.6}$$

$$CaCO_3 + heat \rightarrow CaO + CO_2 \tag{2.7}$$

$$CaO + H_2O \rightarrow Ca(OH)_2 \tag{2.8}$$

Besides heat energy, the DAC system also needs electricity for blowing air, spraying the aqueous and moving material. The fully electrified high-temperature DAC used in this thesis is practically possible [40] to deliver a sustainable and affordable DAC system.

2.4. Electricity Sector Modelling

The electricity sector is the backbone of the whole energy system, as electrification leads to a more intense coupling among energy sectors. More electrification brings the expansion of generation, transmission, and distribution of the electricity sector. Conversely, the integration of other sectors can also enhance flexibility and improve the electricity sector's efficiency and reduce the cost of energy supply. This thesis considers the whole electricity system, including various scales of the system from large scale generation and transmission assets to distribution networks with high-voltage and low-voltage, as well as storage facilities.

As the delay and unfavourable market conditions of the nuclear industry in the UK, the diversification of the generation mix would increase the future UK electricity sector's resilience and bring benefits for the whole UK energy system. Various electricity generation technologies are considered to decarbonise the electricity sector in this thesis. Fossil-fuel based high-carbon generation includes combined cycle gas turbines (CCGT) and open-cycle gas turbines (OCGT). The conventional low-carbon generation includes nuclear and gas-ccs generation. Renewable electricity generation includes wind turbines, solar photovoltaics (PV) for residential and industrial segments and hydropower, as well as bioenergy-fuelled generation (e.g., BECCS and BECHPCCS). Hydrogen is a clean energy carrier that can also enable the decarbonisation of the electricity sector. Hydrogen-fuelled CCGT, OCGT, and combined heat and power (CHP) plants can provide low-carbon and flexible generation [41], which are also considered in this thesis.

The electricity transmission network expansion and reinforcement of high-voltage and low-voltage distribution networks are also considered in this thesis. The EES, including grid-scale bulk storage (BES) on the transmission level and distributed storage (DES) on the distribution level, are also considered in the modelling framework to investigate the potential value they bring to the whole system.

2.5. Heat Sector Modelling

At present, natural gas is the primary fuel choice for heat provision in GB; around 80% of heat demand in GB are using natural gas for residential heating [11]. However, electrification of heating through high-efficiency HP or the use of alternative low carbon heating technologies such as HB is gaining support in the UK as a result of the need to meet the 2050 carbon reduction target.

The future heating supply system should not rely on a single heating technology alone but a comprehensive analysis of system integration and interaction with other energy systems. In this thesis, the district heating and end-use heating appliances are two methods for supplying heat demand. Hybrid heating technologies which combine different heating appliances are also considered in this thesis. As the investment cost of TES is much lower than that of EES, TES is also included in the modelling framework to investigate its potential value to the whole system.

District heating currently only supplies around 2% of the heat demand in the GB [42] due to its high capital cost of the district heating network (DHN), which is also the critical limitation for its large-scale deployment. In this thesis, the heating network sources are industrial HP, industrial NGB and HB and hydrogen-fuelled CHP, BECHPCCS. The district heating system can provide significant flexibility for the electricity sector through the coordinated operation with centralised TES (CTES) or interruption operation of different heating technologies. The deployment of CTES on the DHN can also indirectly provide balancing and ancillary services by reducing the output of HP and increasing the electricity output of and hydrogen-fuelled CHP and

BECHPCCS. Meanwhile, TES can also promote renewable energy accommodation while reducing the peak demand of total electricity demand.

In this thesis, assuming the end-use NGB, end-use HP and end-use HB are deployed to support GB's heat demand. The air-source HP is adopted, which is more suitable for domestic deployment. However, the large-scale deployment of HP will bring additional investment in electricity generation and reinforce the distribution network. Those factors will restrict the shift of the heating supply from NGB to HP to fulfil the carbon emissions reduction in the heat sector. It is worth noting that HP can provide flexibility to the electricity sector through short-term interruption operation [43]. The deployment of HB will need additional investment cost on the hydrogen supply infrastructures. However, HB and hydrogen infrastructures' capital cost is much lower than the HP and electricity infrastructures.

Hybrid heating technologies which combine HP with NGB (HP-B) and HP with HB (HP-HB) are also considered to supply heat demand in this thesis. The hybrid heating technologies can switch during operation between different appliances according to the different situations. For example, HP-B can switch from natural gas to electricity for supplying heat when the renewable generation in the electricity sector is redundant that would otherwise be curtailed, vice versa at times of peak electricity demand, the NGB can be used as a backup. Similarly, due to the massive investment in the large-scale deployment of HP, HB can be used to cover the peak load through a more economical pathway. Meanwhile, compared to NGB, the zero-emission feature of HB is more suitable in low-carbon scenarios. The end-use TES (DTES) is considered to deploy for the households.

2.6. Transport Sector Modelling

This thesis assumes that EV and HFCV are two options to replace conventional fossil fuel vehicle (FV) in the transport sector. Electrified transportation will increase the investment in the electricity generation and reinforcement of the distribution network. However, EV's operating pattern also has the potential flexibility to perform demand-side response (DSR) and frequency response. As an application of hydrogen in the transport sector, HFCV also brings the zero-emission feature to help achieve decarbonisation target in the transport sector.

2.7. Modelling Framework

In the MES context, the large variability of energy demand, including electricity, heat, transport and hydrogen demand, coupled with intermittent wind, solar and hydro energy, requires interactive cooperation among energy sectors.

In order to dampen the intermittency problems and perform demand response in the integrated energy system, leading to a flexible and reliable energy system during the GB's transition to a low-carbon future, interactions take place through the energy conversion between different carrier to supply energy demand should be considered to ensure optimal and secured operation.

Based on the energy sectors and technologies mentioned above, the interactions among different energy sectors are illustrated in Figure 2.1. GHR and EL link hydrogen with the natural gas and electricity sectors together, respectively. The electricity generation can also use hydrogen as a fuel to make electricity and hydrogen sectors interactive. In this thesis, the transport demand is extracted from the National Transport Survey database which contains detailed information on all journeys conducted by light vehicles, including starts and ends of individual journeys grouped according to distances travelled [44]. On average, about 67.4 million journeys are recorded each day, made by about 34.2 million vehicles. Assuming that all energy consumption of the entire light vehicles (i.e., transport demand) is converted into electricity with average energy consumption of 0.15 kWh/km, which needs hourly energy balance [45]. In this modelling framework, the transport demand can be supplied by electricity or hydrogen through EV with slow or fast charging connected to the low-voltage distribution network and HFCV, respectively, implying that electricity and hydrogen sectors are also coupled in the transport sector. The HB can function in the same way as NGB in the heating system but brings zero-emissions, maintaining resilience for householders by promoting energy carriers' diversity. The heat sector is also linked to the hydrogen sector.

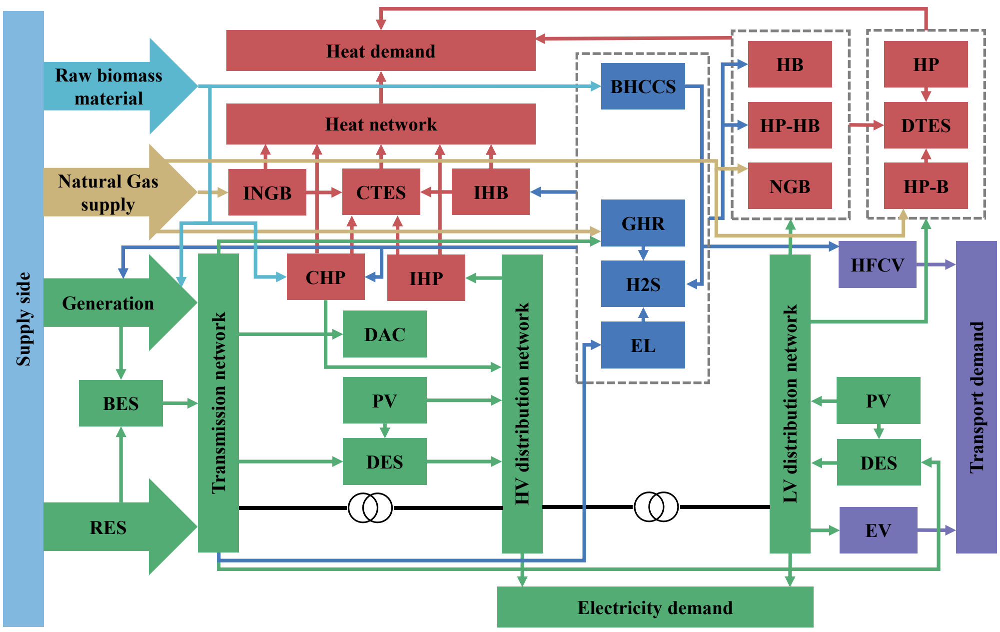

Figure 2.1. Possible interactions among different energy sectors and technologies.

In summary, the different sectors are interconnected through various technologies. The proposed model structure in this thesis captures the interactions across diverse energy sectors. It can optimise the energy supply, transmission, distribution and storage infrastructures requirements within the specific operating constraints, meeting the carbon targets. The models and studies presented in the following chapters of this thesis are based on this chapter’s modelling structure and assumptions to analyse and optimise the energy system for GB 2050.

Chapter 3. Single-year Multi-Energy Systems Optimisation Model

3.1. Introduction

Chapter 2 proposes a comprehensive modelling framework for the whole system optimisation of the integrated electricity, heat and transport sectors, considering integrating hydrogen and NETs, which can be used for different investment timescales and covering national and local levels. The proposed framework is quite flexible and allows optimising investments in the stand-alone energy sector or multiple energy sectors.

In the present chapter, a single-year MES optimisation model is proposed based on Chapter 2. It simultaneously optimises the electricity generation's investment, reinforcement of electricity transmission and distribution networks, DHN, heating devices, and hydrogen supply chain (including hydrogen production plants, hydrogen transmission network and storage), as well as the short-term operating cost. The flexibility provided by different technologies to supply frequency response and operating reserve in the electricity sector is considered. Carbon emission constraint is also included.

The remainder of this chapter's outline is organised as follows: Section 3.2 explicitly presents the components of the objective function for the proposed model. Section 3.3 describes the main operating constraints for each energy sector and technology.

3.2. Objective Function

The present chapter’s proposed model is formulated as a MILP problem with a 1-year time horizon and hourly time resolution to capture the interactions across investment and operating decisions. The objective function (3.1) is to minimise the overall annualised investment and operation cost of the whole system.

The present chapter’s model excludes the NETs integration and only considers the EV and HFCV to support the future low-carbon transport demand, which excludes the conventional FV. It also assumes the capital cost of EV and HFCV is the same. Therefore, their costs can be omitted from the optimisation problem; the portfolio of EV and HFCV is optimised based on their system integration costs rather than by the vehicle’s capital cost. It is trivial to include different EV and HFCV costs in the objective function; at present, it is the interest of this chapter to evaluate the competitiveness of these technologies based on their system integration costs. In this thesis, the carbon price is not taken into account in the operating cost but can be easily added. Details about the formulation of the overall cost in each energy sector are given as follows:

$$Min\ \varphi = TC_e + TC_{hn} + TC_{ed} + TC_{h2} \tag{3.1}$$

The electricity sector investment cost includes the annualised capital cost of newly-built generation and their fixed and variable operations & maintenance (O&M) cost of all the generation units, reinforcement cost of transmission, and distribution networks (3.2). In the mathematical formulation, O&M costs are included in the capital costs for simplicity. The electricity sector’s operational cost consists of the fuel cost, no-load cost, and start-up cost of conventional generators. The fuel cost can be expressed as a function of generation output ($P_{t,g} \cdot o_g$). No-load cost is determined by the number of online units ($\mu_{t,g} \cdot nl_g$), and start-up cost is determined by the number of start-up units ($st_{t,g} \cdot su_g$).

$$TC_e = \sum_{g=1}^{G} c_g \cdot n_g \cdot \bar{P}_g + \sum_{r=1}^{R} (c_{hv_r} \cdot n_{hv_r} + c_{lv_r} \cdot n_{lv_r})$$
$$+ \sum_{l=1}^{L} c_{e_l} \cdot n_{e_l} + \sum_{t=1}^{T} \sum_{g=1}^{G} \left(P_{t,g} \cdot o_g + \mu_{t,g} \cdot nl_g + st_{t,g} \cdot su_g\right) \tag{3.2}$$

The heat sector costs have two components: cost of DHN and cost of end-use heating appliances. The cost of district heating is formulated in (3.3). District heating is supplied by industrial HP, NGB, and HB. The investment cost of DHN can be calculated by a function that is decided by the length of pipework and the geographic features, which is sensitive to heat density [19]. In this thesis, the unit investment cost of DHN is converted to be related to the heat demand. The operation cost of industrial NGB can be determined by the fuel cost of natural gas and heat output of industrial NGB.

$$TC_{hn} = \sum_{r=1}^{R} (c_{hp_r} \cdot n_{hp_r} + c_{ngb_r} \cdot n_{ngb_r} + c_{hb_r} \cdot n_{hb_r})$$
$$+ \sum_{t=1}^{T} \sum_{r=1}^{R} \left(c_{hn_r} \cdot DH_t \cdot \lambda_{hn_r} + o_{ngb_r} \cdot \frac{H_{t,ngb_r}}{\eta_{ngb}} \right) \tag{3.3}$$

End-use heating appliances' investment cost includes the capital cost of end-use HP, NGB, and HB and hybrid HP-B and hybrid HP-HB (superscripted by hy). End-use heating appliances' operational cost is mainly from the natural gas consumption of end-use NGB. The total cost of end-use heating can be formulated as (3.4).

$$TC_{ed} = \sum_{r=1}^{R} \left\{ \begin{matrix} c_{ehp_r} \cdot n_{ehp_r} + c_{engb_r} \cdot nh_r \cdot \left(\lambda_{ngb_r} + \lambda_{engb_r}^{hy}\right) \\ +c_{ehb_r} \cdot nh_r \cdot \left(\lambda_{ehb_r} + \lambda_{ehb_r}^{hy}\right) \end{matrix} \right\}$$
$$+ \sum_{t=1}^{T} \sum_{r=1}^{R} o_{ngb_r} \cdot \frac{H_{t,engb_r}}{\eta_{engb}} \tag{3.4}$$

The hydrogen system's investment cost includes the annualised capital cost of the EL, GHR-CCS, H2S, and the hydrogen transmission pipelines. The operational cost in the hydrogen system refers to the natural gas consumption of GHR-CCS. The total cost of hydrogen integration can be formulated as (3.5).

$$\begin{aligned} TC_{h2} = & \sum_{i=1}^{I} \left(c_{el_i} \cdot n_{el_i} + c_{ghr_i} \cdot n_{ghr_i} + c_{hs_i} \cdot n_{hs_i} \right) \\ & + \sum_{i=1}^{I} \sum_{t=1}^{T} o_{ghr_i} \cdot \frac{Q_{ghr_i,t}}{\eta_{ghr}} + \sum_{l=1}^{L} c_{ht_l} \cdot n_{ht_l} \end{aligned} \tag{3.5}$$

3.3. Constraints

The proposed model in the present chapter is subject to several constraints in each energy sector while minimising the whole system cost and meeting specific carbon targets. All constraints are applied to each time interval within the optimisation time horizon ($\forall t \in T$) for all locations and regions ($\forall i \in I,\ \forall r \in R$), as well as all electricity generation ($\forall g \in G$).

3.3.1. Energy Balance Constraints

Regional energy demand includes electricity demand, heat demand and transport demand, and hydrogen demand in each time interval should be satisfied by the various supply technologies from different energy sectors.

Electricity balance constraints: The electricity balancing constraints are formulated as (3.6). The electricity demand consists of non-heat-based demand ($DE_{t,r}$), the electricity consumption of HP in the heating system ($H_{t,hp_r}/\eta_{hp} + H_{t,ehp_r}/\eta_{t,ehp_r}$), and the electricity consumption of EL ($Q_{t,el_r}/\eta_{el}$) in the hydrogen system and EV (V_{t,ev_r}) in the transport sector.

$$\sum_{g=1}^{G} P_{g,t} = \sum_{i=1}^{I} \frac{Q_{t,el_r}}{\eta_{el}} + \sum_{r=1}^{R} \left(DE_{t,r} + \frac{H_{t,hp_r}}{\eta_{hp}} + \frac{H_{t,ehp_r}}{\eta_{t,ehp_r}} + V_{t,ev_r} \right) \tag{3.6}$$

For the end-use HP, the coefficient of performance (COP) of ASHP changes with the ambient temperature. The industrial HP is typically sourced from temperature-stable heat sources, so the COP of the industrial HP is assumed to be constant for simplicity.

Heat balance constraints: The heat demand supplied by the districting heating is formulated in (3.7). The heat demand met by the stand-alone end-use NGB is expressed as (3.8), and stand-alone end-use HP and HB supply heat demand by (3.9) and (3.10), respectively. The heat demand balances of two hybrid heating combinations HP-B and HP-HB are formulated in (3.11) and (3.12). Heat demand is supplied by either districting heating or end-use appliances (3.13).

$$H_{t,hp_r} + H_{t,ngb_r} + H_{t,hb_r} = DH_{t,r} \cdot \lambda_{hn_r} \tag{3.7}$$

$$H_{t,egb_r} = DH_{t,r} \cdot \lambda_{egb_r} \tag{3.8}$$

$$H_{t,ehp_r} = DH_{t,r} \cdot \lambda_{ehp_r} \tag{3.9}$$

$$H_{t,ehb_r} = DH_{t,r} \cdot \lambda_{ehb_r} \tag{3.10}$$

$$H_{t,ehp_r}^{hy,engb} + H_{t,egb_r}^{hy,engb} = DH_{t,r} \cdot \lambda_{engb_r}^{hy} \tag{3.11}$$

$$H_{t,ehp_r}^{hy,ehb} + H_{t,ehb_r}^{hy,ehb} = DH_{t,r} \cdot \lambda_{ehb_r}^{hy} \tag{3.12}$$

$$\lambda_{hn_r} + \lambda_{egb_r} + \lambda_{ehp_r} + \lambda_{ehb_r} + \lambda_{engb_r}^{hy} + \lambda_{ehb_r}^{hy} = 1 \tag{3.13}$$

Transport demand balance constraints: The transport demand is supplied by EV and HFCV (3.14)-(3.16). Various specific types of demand can be associated with different flexibility levels, like EVs and HP, respectively. EV is modelled as a flexible load in the present model that can provide demand-side management (DSR). Equations (3.17) and (3.18) describe the demand reduction and the energy balance for demand shifting.

$$V_{t,ev_r} = \lambda_{ev_r} \cdot DT_{t,r} + dsr_{t,r}^{+} - dsr_{t,r}^{-} \tag{3.14}$$

$$V_{t,hfcv_r} \cdot \frac{\eta_{ev}}{\eta_{hfcv}} = \lambda_{hfcv_r} \cdot DT_{t,r} \tag{3.15}$$

$$\lambda_{ev_r} + \lambda_{hfcv_r} = 1 \tag{3.16}$$

$$dsr_{t,r}^{-} \leq \varepsilon \cdot DT_{t,r} \tag{3.17}$$

$$\sum_{t\in D} dsr_{t,r}^{-} \leq \eta_{dsr} \cdot \sum_{t\in D} dsr_{t,r}^{+} \tag{3.18}$$

Hydrogen demand balance constraints: The hydrogen consumption is from the hydrogen-fuelled generation, HB and HFCV, supplied by EL, GHR-CCS. The H2S charge and discharge are also considered in the hydrogen demand balance (3.19).

$$\sum_{i=1}^{I}\left(Q_{t,el_i} + Q_{t,ghr_i} + S_{t,hs_i}^{+} - S_{t,hs_i}^{-}\right) = \sum_{g\in I_i} \frac{P_{t,h2_g}}{\eta_{h2_g}} + \sum_{r=1}^{R}\left(\frac{H_{t,hb_r}}{\eta_{hb}} + \frac{H_{t,ehb_r}}{\eta_{ehb}} + V_{t,hfcv_r}\right) \tag{3.19}$$

3.3.2. Energy Production Constraints

The energy production constraints in the electricity sector consider all the possible operation constraints of the thermal generation units in the unit-commitment problem, including ramp up/down, start-up, synchronisation, desynchronisation, and minimum up and down time constraints, capturing the short-term operational decisions, to enhance and strengthen the accuracy of the decisions to guarantee the stability of energy system. The heat and hydrogen production constraints are mainly the output limitation of each technology.

The minimum stable generation and the maximum output of thermal generation units constraints are formulated as (3.20) and (3.21).

$$\mu_{t,g} \cdot \underline{P}_g \leq P_{t,g} \leq \mu_{t,g} \cdot \overline{P}_g \tag{3.20}$$

$$\mu_{t,g} \leq \overline{n}_g + n_g \tag{3.21}$$

As formulated in (3.22) and (3.23), the model considers the limitation of the ramping rate of generation units. The number of start-up and shut down units are limited by

(3.24)-(3.25). The minimum up and down time constraints are formulated as (3.26)-(3.27).

$$P_{t,g} - P_{t-1,g} \leq \mu_{t,g} \cdot R_g^u \tag{3.22}$$

$$P_{t-1,g} - P_{t,g} \leq \mu_{t,g} \cdot R_g^d \tag{3.23}$$

$$st_{t,g} \geq \mu_{t,g} - \mu_{t-1,g} \tag{3.24}$$

$$dst_{t,g} \geq \mu_{t-1,g} - \mu_{t,g} \tag{3.25}$$

$$\sum_{k=t-\underline{up}_g}^{t-1} st_{t,g}^k \leq \mu_{t,g} \tag{3.26}$$

$$\mu_{t,g} \leq \overline{n}_g + n_g - \sum_{k=t-\underline{down}_g}^{t-1} dst_{t,g}^k \tag{3.27}$$

The annual energy production limits of thermal generation (3.28) are also considered associated with scheduled inspection and maintenance.

$$\sum_{t=1}^{T} P_{t,g} \leq af_g \cdot T \cdot \left(\overline{n}_g + n_g\right) \tag{3.28}$$

The heat and hydrogen production constraints are mainly the output limitation of each technology and are expressed in (3.29) and (3.30) for brevity.

$$H_{t,h} \leq \overline{n}_h + n_h \tag{3.29}$$

$$Q_{t,h2} \leq \overline{n}_{h2} + n_{h2} \tag{3.30}$$

3.3.3. Energy Flow Constraints

The energy supply and balances are satisfied on a regional basis instead of a single entity in the present model. The characteristics of natural resources and diversity of demand in different regions differ from each other. Therefore, various energy transmission networks may need to be expanded or newly built. In this model, the transportation model [46] is adopted to optimise the transmission networks' location and capacity requirements. Equations (3.31) and (3.32) represents the transmission limits in the electricity and hydrogen sectors, respectively. They are applied to all transmission lines or pipelines ($\forall l \in L$).

$$-(\overline{n}_{el} + n_{e_l}) \leq f_{t,e_l} \leq \overline{n}_{el} + n_{e_l} \quad (3.31)$$

$$-(\overline{n}_{h2_l} + n_{h2_l}) \leq f_{t,h2_l} \leq \overline{n}_{h2_l} + n_{h2_l} \quad (3.32)$$

The electrification of the heat and transport sector requires the reinforcement of the electricity distribution network. The expansion of electricity distribution networks, including high-voltage and low-voltage distribution networks, is considered a function of peak load in the local distribution system [18]. The distribution networks reinforcement constraints at high-voltage and low-voltage levels are formulated in (3.33)-(3.34). The peak distribution flows can be driven by load but also generation. Significant increase of distributed generation penetration like PV, micro-CHP may occasionally drive the net energy flowing in the opposite direction from consumers back into the grid. There is also a certain level of peak reverse power flow the distribution network can handle without reinforcement. It is usually lower than the normal direction power flow limit due to protection schemes. In this thesis, if the reverse flow in that distribution network is higher, it will either require the network to be reinforced or PV output to be curtailed. With high PV penetrations, the distribution network may also need to be reinforced to handle increased reverse power flows triggered by high PV output. These situations are formulated as (3.35)-(3.36).

$$\xi \cdot DE_{t,r} + \frac{H_{t,hp_r}}{\eta_{hp}} + \frac{H_{t,ehp_r}}{\eta_{t,ehp_r}} + V_{t,ev_r} - P_{t,pv_r}^{hv} - P_{t,pv_r}^{lv} \leq \overline{n}_{hv_r} + n_{hv_r} \quad (3.33)$$

$$(1-\xi) \cdot DE_{t,r} + \frac{H_{t,ehp_r}}{\eta_{t,ehp_r}} + V_{t,ev_r} - P_{t,pv_r}^{lv} \leq \overline{n}_{lv_r} + n_{lv_r} \quad (3.34)$$

$$P_{t,pv_r}^{hv} + P_{t,pv_r}^{lv} - \xi \cdot DE_{t,r} - \frac{H_{t,hp_r}}{\eta_{hp}} - \frac{H_{t,ehp_r}}{\eta_{t,ehp_r}} - V_{t,ev_r} \leq \sigma_{hv} \cdot \left(\overline{n}_{hv_r} + n_{hv_r}\right) \quad (3.35)$$

$$P_{t,pv_r}^{lv} - (1-\xi) \cdot DE_{t,r} - \frac{H_{t,ehp_r}}{\eta_{t,ehp_r}} - V_{t,ev_r} \leq \sigma_{lv} \cdot \left(\overline{n}_{lv_r} + n_{lv_r}\right) \quad (3.36)$$

3.3.4. Ancillary Services Constraints

In the electricity sector planning and operation, multiple sources of uncertainty, including intermittency of RES output, load variability, and generation outages, need to be considered to capture the future low-carbon electricity system's operation challenges. Sufficient balancing services (e.g., frequency response and operating reserve) and backup capacity will be needed to deal with the uncertainty. The volume of frequency response required is a function of the possible largest loss-in-feed and the system inertia. The operational reserve requirement is determined by a statistical approach considering the forecasting errors of RES output, electricity load and generation outages. In this model, frequency response and operating reserve requirements are derived using the approach based on the previous work presented in [47] and [48]. Besides traditional generators, the supplementary frequency and operating reserve can be provided by HP, EL and EV as interruptible load.

The frequency response constraints and operating reserve constraints are formulated in (3.37) and (3.38), respectively. The ancillary services provided by the generation units are limited by (3.39)-(3.41).

$$\sum_{g=1}^{G} rsp_{t,g} + \sum_{r=1}^{R}\left(rsp_{t,hp_r} + rsp_{t,ehp_r} + rsp_{t,ev_r} + rsp_{t,el_r}\right) \geq \overline{SF}_t \tag{3.37}$$

$$\sum_{g=1}^{G} res_{t,g} + \sum_{r=1}^{R}\left(res_{t,hp_r} + res_{t,ehp_r} + res_{t,ev_r} + res_{t,el_r}\right) \geq \overline{SR}_t \tag{3.38}$$

$$rsp_{t,g} \leq \mu_{t,g} \cdot \overline{rsp}_g \tag{3.39}$$

$$res_{t,g} \leq \mu_{t,g} \cdot \overline{res}_g \tag{3.40}$$

$$\mu_{t,g} \cdot \underline{P}_g \leq P_{t,g} + rsp_{t,g} + res_{t,g} \leq \mu_{t,g} \cdot \overline{P}_g \tag{3.41}$$

The frequency response and operating reserve provided by the end-use heating system, EL and EVs are also limited by their maximum output. The ancillary services provided by HP are based on constraints (3.42)-(3.44). The ancillary services constraints for other technologies are developed in the same way and are omitted here for simplicity.

$$rsp_{t,hp_r} \leq H_{t,hp_r}/\eta_{hp} \tag{3.42}$$

$$res_{t,hp_r} \leq H_{t,hp_r}/\eta_{hp} \tag{3.43}$$

$$H_{t,hp_r} + rsp_{t,hp_r} + res_{t,hp_r} \leq H_{t,hp_r}/\eta_{hp} \tag{3.44}$$

3.3.5. Energy Storage Constraints

In order to create a more flexible and reliable energy system during the GB's transition to a low-carbon future, cost-effective and efficient storage is treated as a key technology to meet different flexibility needs of the MES.

In the present model, considering the expensive investment cost for large scale deployment of EES to facilitate the mass integration of RES, H2S can potentially serve as an alternative, when coordinated with other hydrogen-related technologies, to fulfil the same functionality at a lower cost due to its lower capital cost. Meanwhile, the hydrogen system also relies on H2S to balance the highly variable hydrogen demand.

The maximum discharging and charging rate of H2S is formulated by (3.45) and (3.46), respectively.

$$S^{+}_{t,hs_i} \leq \overline{n}_{hs_i} \tag{3.45}$$

$$S^{-}_{t,hs_i} \leq \overline{n}_{hs_i} \tag{3.46}$$

The constraints (3.47) are associated with the amount of energy stored, and the storage energy balance is formulated in (3.48).

$$SC_{t,hs_i} \leq \overline{n}_{hs_i} \cdot est_{hs_i} \tag{3.47}$$

$$SC_{t,hs_i} = SC_{t-1,hs_i} - S^{-}_{t,hs_i} + \eta_{hs} \cdot S^{+}_{t,hs_i} \tag{3.48}$$

3.3.6. Carbon Emissions Constraints

The total carbon emissions of the whole system do not exceed the regulated carbon targets (3.39). The carbon targets can be defined as the number of carbon emissions (tonnes) from all energy sectors, including electricity, heat, transport and hydrogen sectors, or the product of the given carbon target (g/kWh) and the annual energy demand. In the present model, the carbon emissions mainly come from the conventional thermal generation (CCGT and OCGT) from the electricity sector, NGBs from the heat sector and GHR-CCS from the hydrogen sector.

$$\sum_{t=1}^{T}\sum_{g=1}^{G} P_{t,g} \cdot ce_g + \sum_{t=1}^{T}\sum_{r=1}^{R}\left(H_{t,ngb_r} \cdot ce_{ngb} + H_{t,engb_r} \cdot ce_{engb}\right)$$
$$+\sum_{t=1}^{T}\sum_{i=1}^{I} Q_{t,ghr_i} \cdot ce_{ghr} \leq CT \cdot \sum_{t=1}^{T}\sum_{i=1}^{I}\left(DE_{t,i} + DH_{t,i} + DT_{t,i}\right) \quad (3.39)$$

Chapter 4. Evaluating Strategies for Decarbonising the Transport Sector in Great Britain

4.1. Introduction

At present, the transport sector continues to be the largest emitting sector in the UK. The carbon emissions from domestic transport of UK have risen since 2013, which bring calls for stronger decarbonisation strategies [49]. Two approaches for decarbonising transport sectors, i.e., electrification and a shift from fossil fuel to hydrogen, are evaluated in this paper. The first strategy assumes that all transportation fleets will be electrified. The flexibility that EV can potentially provide to improve the integration of low-carbon generation technologies and EV is taken into account. The second strategy assumes all vehicles will be fuelled by hydrogen.

The flexibility of hydrogen offers a variety of services, crossing between electricity, heat and transport sectors. A few previous research [50] and [51] focus on the interactions of hydrogen with electricity and gas systems from the perspective of operation. In the electricity sector, hydrogen can be an alternative means of providing low-carbon generation and competitive energy storage and delivering balancing services or frequency control. Surplus renewable power can produce hydrogen by EL, which can also offer frequency responses services. There is a potential to increase the generation and utilization of renewable energy by integrating the electricity network with other energy carriers [52]. In [53], the benefits of flexible gas-fired plants, electricity storage and P2G process on the system with high penetration of renewable energy are demonstrated.

Currently, hydrogen enters the energy market, mostly in stand-alone applications. There is no national or local transmission and distribution network. A few previous papers about the decarbonisation of the transport sector can be found from the recent research. The demand for EVs is modelled in [45] according to a detailed National Transport Survey database, which quantifies the order of magnitude impact on the UK electricity distribution network of electrifying the transport sector. Pudjianto et al. [54] adopt various smart network control and demand response technologies to enhance the integration of future electrified transport demand. In [55], a future hydrogen supply chain is designed for the UK, which considers the production, storage and distribution. Hydrogen energy is used to supply the transport demand. The model decides the number, location, and capacity of hydrogen production plants and optimises the total costs of the hydrogen supply chain. Almansoori et al. [56] extend the work carried out in [55], which considers the supply of primary energy sources. The local distribution of hydrogen is also designed for the future hydrogen-based transport load. The market penetration analysis of HFCVs is performed over a long-term planning horizon. Reference [57] considers the uncertainty of demand into the model based on [56]. Samsatli et al. [58] present an integrated wind-electricity-hydrogen model for the future 100% penetration of HFCVs. The model aims to minimise the network's overall costs, subject to satisfying the decarbonised transportation sector in the GB.

Hydrogen has often been criticised for being an inefficient way of using energy. A system-level approach is necessary to gain a better understanding of the investment implications for deploying hydrogen infrastructures. In [18], Pudjianto et al. propose a whole system model of the electricity system that optimises the investment and operation cost of generation, transmission and distribution networks at the national level. Based on this approach, reference [59] compares different heating decarbonisation strategies through the coordinated operation with the electricity system.

Adopting the MES optimisation model proposed in Chapter 3, this chapter evaluates different strategies to decarbonise the transport sector and the consequential impacts on the total investment and operation cost across electricity, transport and hydrogen sectors, and the implications on the electricity sector. The case studies compare the decomposed system cost of adopting EV and HFCV with different strategies individually. The optimal portfolio of electricity generation and vehicles is presented.

The outline of the remainder of this chapter is organised as follows: Section 4.2 describes the system detail used in this chapter and the scenario set in the case studies part. Section 4.3 presents a series of case studies. Finally, Section 4.4 discusses the conclusions.

4.2. System Description and Scenario Setting

The MES in the present chapter considers the electricity, transport and hydrogen sectors at the system level. Interactions take place through the conversion of energy between different energy carriers. The numerous possible interactions between each energy sectors are shown in Figure 4.1. The hydrogen pathway evaluated in this model is based on deploying HFCV to supply transport demand. The hydrogen can also be used as the fuel of electricity generation to make electricity and the hydrogen system interactive.

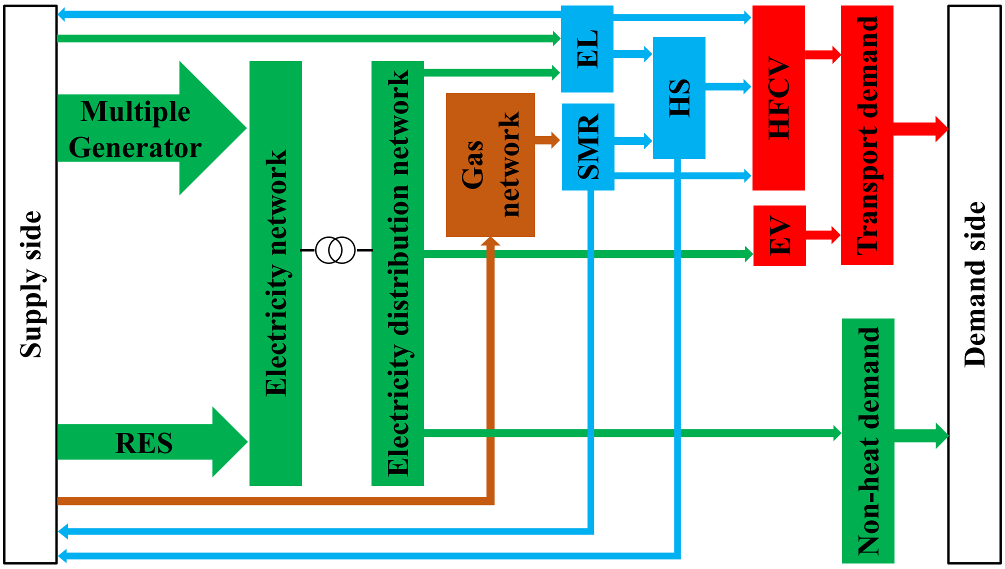

Figure 4.1. Possible interactions among electricity, transport, and hydrogen sectors in the proposed MES.

The proposed scenarios in this chapter are tested in a simplified GB system. The GB transmission system is characterised by North to South power flows and represented by five main regions: 1). Scotland (SCOT), 2). North England and Wales (EW-N), 3). Middle England and Wales (EW-M), 4). South England and Wales (EW-S), and 5). London (embedded in the EW-S region). Figure 4.2 illustrates this simplified GB network's topology together with the transmission corridors connecting the key regions, which apply for both electricity and hydrogen transmission. It is worth noting that for simplicity, transmission corridors within each region are not considered in the model, which underestimates the investment costs of electricity and hydrogen transmission networks.

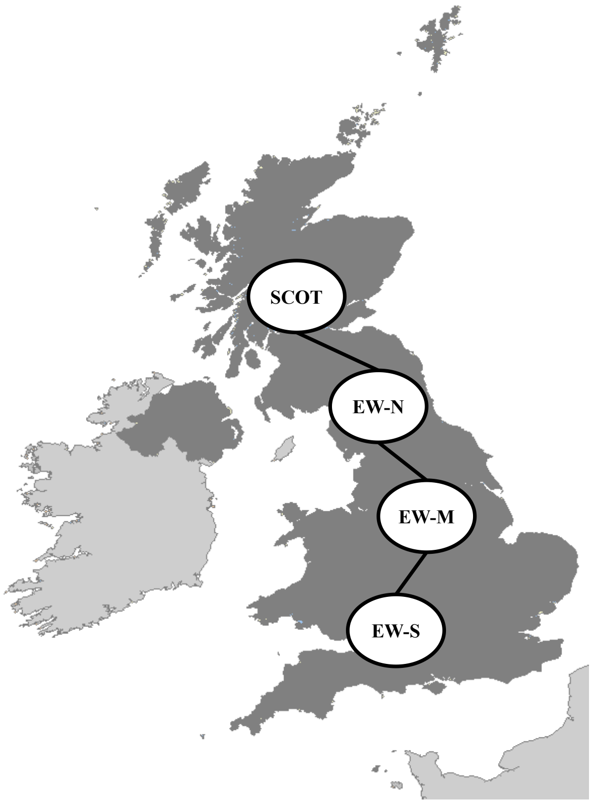

Figure 4.2. The topology of the simplified GB system.

In the electricity sector, conventional high-carbon generation (e.g., CCGT and OCGT) and low-carbon generation, including nuclear, gas-ccs and hydrogen-fuelled generation, and the RES generation (wind and PV) are considered in the model. SMR and ATR are the natural gas-based hydrogen production technologies used in this study. Seven scenarios are investigated as listed in Table 4.1. The carbon target is 10 $MtCO_2$/year.

Table 4.1. Description of different scenarios of transport sector decarbonisation strategies.

Scenarios	Description
EV	All transport demand is electrified but with no smart charging
EV+H2 Gen	Similar to the EV scenario but hydrogen is integrated into the electricity system to provide an alternative low-carbon energy source.

Smart EV	Similar to EV scenario but with smart charging assuming 80% of EV demand is flexible (i.e., the load can be shifted within the same day).
HFCV	All transport demand is decarbonised using hydrogen, which is produced by SMR with CCS and EL. The efficiency of HFCV is assumed 30% less than the efficiency of EV.
HFCV (adc)	Similar to the HFCV scenario but instead of using SMR, an advanced technology, i.e., ATR, is used. Compare to SMR, ATR has superior performance in terms of cost, energy efficiency and carbon capture rate.
Smart EV+H2 Gen	Similar to EV+H2 Gen scenario but with smart charging.
Combined	The model is used to optimise the proportion of transport fleets that are decarbonised using electrification (with smart charging) or hydrogen (with ATR).

4.3. Case Studies

This section presents a series of case studies to answer RQ1 for this thesis. Besides, this chapter discusses several specific research questions related to RQ1, which can be summarised as follows:

- Quantify the economic performance of different decarbonisation strategies for the integrated electricity and transport sectors under the given carbon target.
- Identify the deployment of each type of vehicles in different locations across the whole nation.
- Investigate the impact of different decarbonisation strategies on the electricity generation capacity and production mix.

4.3.1. Economic Analysis of Different Decarbonisation Options

Figure. 4.4 shows the energy system costs for each scenario under investigation. The costs include the annualised capital cost of hydrogen network, H2S, hydrogen production via SMR/ATR and EL, electricity network, low-carbon generation, e.g., wind, PV, nuclear, gas-ccs, and hydrogen-fuelled generation, high-carbon generation and the annual operating cost of hydrogen system and electricity system. Across all scenarios, the total cost of the energy system in scenario EV is the highest, while the least-cost solution is found in scenario Combined.

The EV case demonstrates that electrification of transport without enabling flexibility will be costly. 48% of the cost represents the investment cost in low-carbon generation. The second and third largest cost is associated with the operating cost of electricity and the distribution network cost. Electrification of transport will increase peak load, which demands new capacity (generation and network) to maintain system security.

As the low-carbon generation's investment cost dominates the first case cost, the second case explores the use of hydrogen to be an alternative source of low-carbon generation. The decrease in electricity generation cost is partially offset by the cost of hydrogen infrastructure and fuel costs. But in total, the integration of hydrogen into the electricity system will reduce the cost by 20%.

In the Smart EV case, the contribution of electrifying the transport to the electricity peak load can be reduced by shifting the EV charging period to off-peak, as shown in Figure 4.3. The peak demand in the third case is 58 GW compared to 73 GW in the 1st case. This mitigates the need to reinforce the electricity network and reduce the low-carbon generation investment and electricity system operating cost. The flexibility provided by smart charging minimises the cost by 21%.

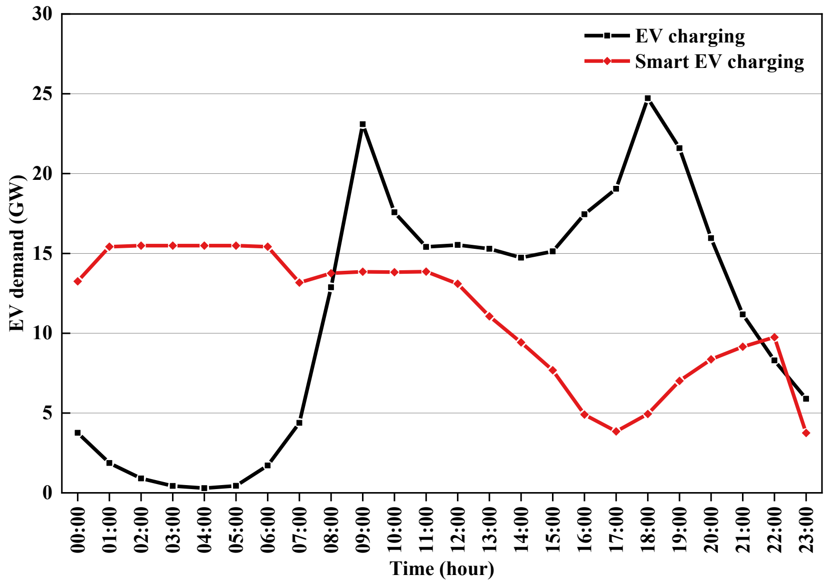

Figure 4.3. Average national EV load profile with and without smart charging.

In the HFCV case, the synergy of using hydrogen to decarbonise both transport and electricity leads to a smaller cost. In this case, using hydrogen transport on the hydrogen production capacity is relatively small, indicating synergy across the electricity and transport sectors. As the hydrogen demand increases due to transport, the operating cost of the hydrogen system increases. The use of hydrogen transport will not increase demand for electricity system capacity; e.g., it mitigates the need to reinforce the electricity grid and requires less power generation capacity. The total system cost is £26.1 billion/year.

The fifth and sixth cases demonstrate that the cost of decarbonising the transport sector via electrification or hydrogen (assuming that the cost of hydrogen production can be reduced by using advanced technologies such as ATR) can be comparable. The former will have more low-carbon electricity sources, while the latter will have low-carbon gas.

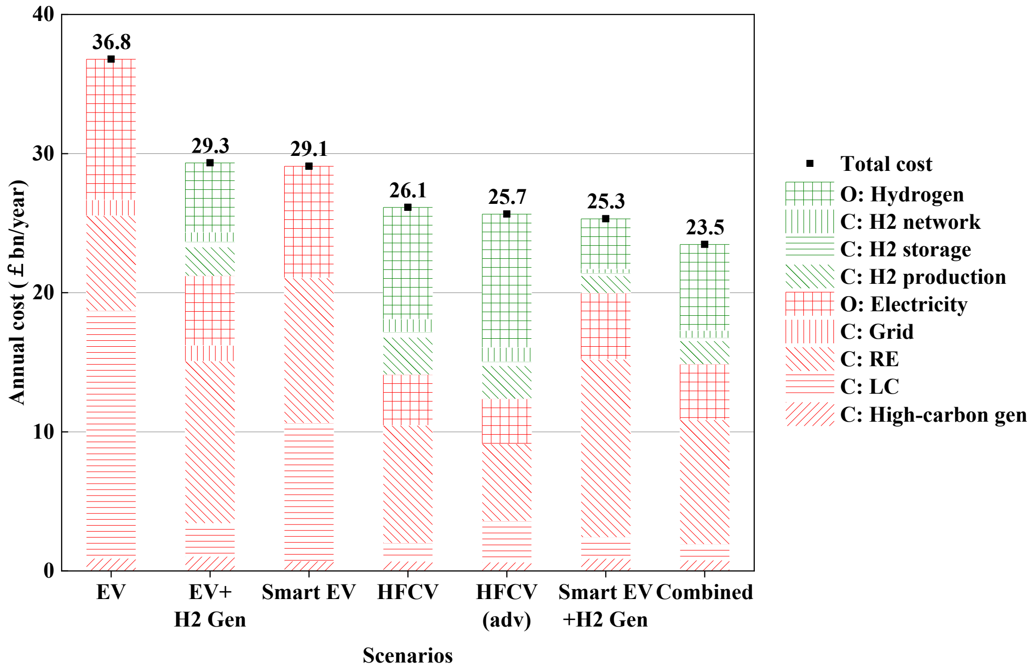

Figure 4.4. Annual system cost of different decarbonisation pathways.

The Combined case demonstrates that the transport sector can be decarbonised through a combination of electrification and hydrogen. The optimal portfolio of EV and HFCV is shown in Figure 4.5. When the HFCV and EV exist together in the market, EV still accounts for most market share due to its higher efficiency. The optimal portfolio of EV and HFCV is sensitive to fuel efficiency; higher efficiency would bring more deployment and lower total system cost. It is important to highlight that at present, the cost of HFCV is still much higher than EV, which makes it less competitive. Large-scale deployments of both EV and HFCV require accompanying infrastructures, such as charging stations and hydrogen refuelling stations.

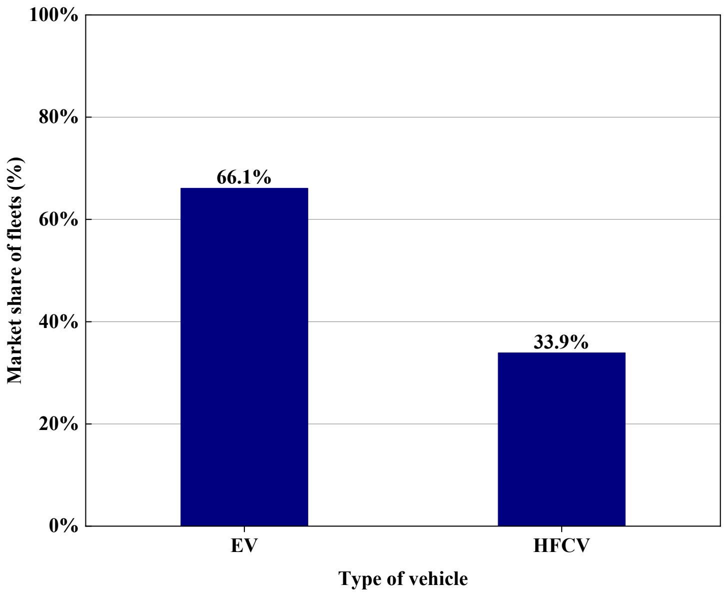

Figure 4.5. The proportion of each transport technology.

4.3.2. The Impact of Different Options on Generation Capacity and Electricity Production Mix

Figure 4.6 show the optimal portfolio of electricity generation capacity and production for each scenario, respectively. In the Smart EV case, the flexibility provided by smart EV charging promotes the integration of renewable energy and reduces the need for high-cost nuclear generation.

In cases where hydrogen is used as an alternative source of low-carbon generation, hydrogen generation can displace the nuclear generation's capacity and post-combustion gas-ccs due to their low capital cost, flexibility, and zero-emission feature. The production of hydrogen generation accounts for around 20%-50% of the total electricity generation. In the HFCV (adv) case, the hydrogen generation contributes 50% of total electricity generation due to the lower cost of hydrogen caused by the use of ATR. This range of studies demonstrates strong interaction across the hydrogen and electricity sectors.

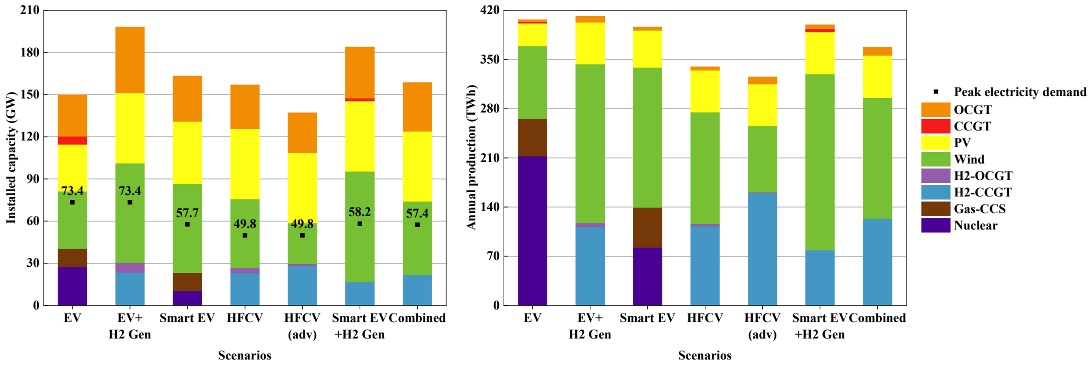

Figure 4.6. The installed capacity of electricity generation technologies (left) and electricity generation (right), as well as the peak electricity demand.

4.4. Conclusions of the Chapter

This chapter adopts the MES optimisation model proposed in Chapter 3 to analyse different options to decarbonise the integrated electricity and transport sectors.

Firstly, the results demonstrate that the transport sector's electrification will increase the cost in the electricity sector, especially in the distribution network (£1.1 billion/year). Therefore, smart charging could be a cost-effective option to reduce the impact of EV integration on the electricity sector. The flexibility provided by smart charging reduces the total cost by 21% compared to the EV scenario. The costs of decarbonising the transport sector through electrification or hydrogen can be comparable but depend on the specific technology application.

Secondly, the combined scenario indicates that opportunities for the coexistence of EV and HFCV in the market are potentially available, but this depends on specific capital costs and fuel efficiency.

Third, hydrogen could be an alternative low-carbon source to provide for the electricity sector and transport sector. The integration of hydrogen into the electricity sector can reduce the cost by 20% compared to the scenario without hydrogen-fuelled generation. The depth of hydrogen integration is dependent on the cost of hydrogen infrastructure and its overall energy efficiency. The advanced hydrogen production technology brings lower overall system cost.

Finally, hydrogen-fuelled generation can replace the conventional firm low-carbon generation like nuclear and gas-ccs due to their lower capital cost, flexibility, and zero-emission feature. It is worth noting that there is a synergy between the hydrogen used in the electricity and transport sectors that will be further explored in Chapter 5. All the results are system-specific and depend on the assumptions taken.

Chapter 5. Integration of Power-to-Gas and Low-Carbon Road Transport in Great Britain's Future Energy System

5.1. Introduction

In the UK, the carbon reduction (i.e., a decrease of only 5% compared to 1990) in the transport sector contrasts to the level of carbon reduction in the electricity sector, which falls by 63% compared to its level in 1990 as more renewables and greener power production technologies penetrate the system.

In order to achieve the net-zero carbon emissions target by 2050, the transport sector needs to be decarbonised together with the decarbonisation of the electricity sector. Low-carbon technologies in both electricity and transport sectors, such as low-carbon thermal generation technologies (nuclear, gas-ccs), RES, and zero-emission vehicle technologies such as EV and HFCV, are vital components to achieve this objective.

However, the energy system implications of adopting EV and HFCV are not clear. If not controlled smartly, EV tends to increase electricity peak demand, requiring substantial investment in the electricity sector, especially low-carbon electricity generation and distribution network. In contrast, HFCV is supplied from hydrogen infrastructure, therefore less disruptive to the electricity system, and needs investment in the hydrogen supply chain.

From the system level perspective, the adoption of HFCV relies on the industrial-scale hydrogen production pathway that efficiently supplies the hydrogen demand in the electricity and transport sector [60], which triggers a fundamental question regarding the decarbonisation of hydrogen production processes. Currently, natural gas produces most of the hydrogen through G2G processes such as SMR due to its economic advantages [33]. However, residual emissions from CCS and hydrogen extraction and the long-term sustainability of this solution are of primary concern. As an alternative, hydrogen can also be produced from renewable energy sources through the P2G facility.

P2G is a technology that converts electricity to gaseous fuel (e.g., hydrogen) through electrolysis. Hydrogen produced can be stored and distributed via the pipelines network. It has been mooted as a low-carbon method to produce clean fuel for the hydrogen-fuelled generation and HFCV while providing ancillary services to the electricity sector [61].

Although EL has the advantage of producing extremely pure hydrogen without carbon emissions, its application is often limited to small scale and unique situations currently due to its relatively high capital cost. In the context of MES, the electricity sector and electromobility are expected to interweave more and more; this leads to a new structure of the overall multi-energy system. As a valid energy conversion option, P2G recovers excess renewable energy to produce carbon-neutral hydrogen. The role of P2G and HFCV in the decarbonisation process and their interactions in the future interactive energy system need to be investigated.

The topic of the impact of P2G in the energy system is broadly present in literature. The reference [62] assesses the operational impact of P2G on the integrated electricity and gas network. The ability of P2G to absorb excess electricity and allows for the provision of ancillary services are demonstrated in [63]. It can also be treated as a storage option to store excess electricity [64], reduce the expansion of grid expansion [65], and alternative primary energy for natural gas [66]. The studies above focus mainly on the interactions between electricity and gas systems. Their models also include the system operation but lack analysis of how P2G affects infrastructure investments in different energy sectors.

The attention to the transition of the low-carbon transport sector appears, and synergies of sector coupling between electricity and transport sectors to be the current research direction. The cross-sector principle between electricity and transport sectors is investigated in [67], and a sector coupling model is developed and tested in the German energy system [68]. The impact of EV demand on the electricity distribution network is investigated in [54]. The flexibility benefits from transport electrification in the electricity system are quantified [43] and [69]. The study in [70] uses DSR with EV to investigate the benefits of flexibility in a whole energy systems model. The benefits of EV in supporting primary frequency control are investigated in [71].

According to the literature review, national-scale studies about EV penetration typically investigate their flexibility and impacts on the electricity system operation without considering the whole system planning and interactions across various energy sectors.

As for the HFCV, using hydrogen as a sustainable fuel for the future transport sector is presented in [72]. The reference [73] proposes two strategies, HFCV and natural gas vehicle, to decarbonise the transport sector and evaluate their impact on the integrated electricity and transport sectors. Still, the test system lacks the spatial feature; the transmission and interconnector between different regions are neglected.

An integrated electricity and transport model at a national level are proposed in [74]. The model adopts P2G technology to supply hydrogen demand in the transport sector. The results indicate with sizeable renewable energy penetration, the coupling with the transport sector is fruitful. Significant amounts of hydrogen can be produced through P2G, thus achieving decarbonisation. However, the electricity sector modelling neglects the operation issue of power generation with simplified assumptions.

Reference [75] proposes a spatial and temporal optimisation model for the power-to-hydrogen application. A hydrogen-to-mobility scenario is investigated in this study, determining the future energy system’s optimal design and operation. However, the electricity system model only considers the RES and ignores the short-term operational features of power plants.

The studies mentioned above [62-66] demonstrate the value of P2G technology in the context of the integrated energy system has been thoroughly investigated in other studies. The different fleet such as EV and HFCV is also evaluated at various levels individually. However, they either do not consider the interactions between different systems or lack the analysis from the whole system level, like the impact of EV penetration on the electricity distribution network, which cannot be handled in previously proposed models.

In order to address the research gaps, this chapter adopts the proposed MES model in Chapter 3 to investigates the role of P2G in the integrated electricity and transport sectors and the combined behaviour of two potential clean fuels for the future transport sector, i.e., electromobility and hydrogen-based mobility. It estimates their relevance in achieving the specific carbon targets.

The outline of the remainder of this chapter is organised as follows: Section 5.2 introduces the system implication and scenario setting of this study. Section 5.3 conducts a series of case studies to evaluate the potential value of P2G to support different energy sectors. The key findings of the studies are synthesised and summarised in Section 5.4.

5.2. System Description and Scenario Setting

In order to assess the role of P2G technology in supporting the hydrogen demand in the electricity and transport sectors and the sector coupling between electricity and road-transport sectors, different scenarios are designed and tested in this subsection under different carbon targets.

The sector coupling in this study is schematised in Figure 5.1. P2G is defined as the process of producing hydrogen via electrolysis, which converts electricity to hydrogen. The H2S is also considered to deal with the intermittent renewable energy and temporal fluctuation of hydrogen demand. Meanwhile, gas-to-power is defined as the process of producing electricity via hydrogen-fuelled generation, which converts hydrogen back to electricity.

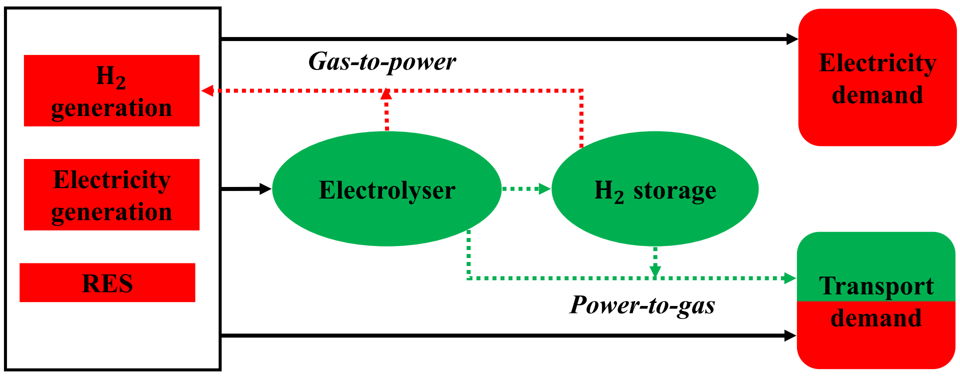

Figure 5.1. Schematic diagram of sector coupling.

This chapter's proposed scenarios are also tested in the simplified GB transmission system presented in Chapter 4. Meanwhile, considering the scheduled interconnection of the GB's electricity system with three neighbouring systems, Ireland (IE), Continental Europe (CE) and Norway (NOR). The dashed line represents no direct line between IE and CE currently. Still, the model will determine whether or not to build new capacity between the two systems if economically justified. This study also optimises the investment and operation in IE and CE, enabling cross-border interactions. The interconnectors are illustrated in Figure 5.2.

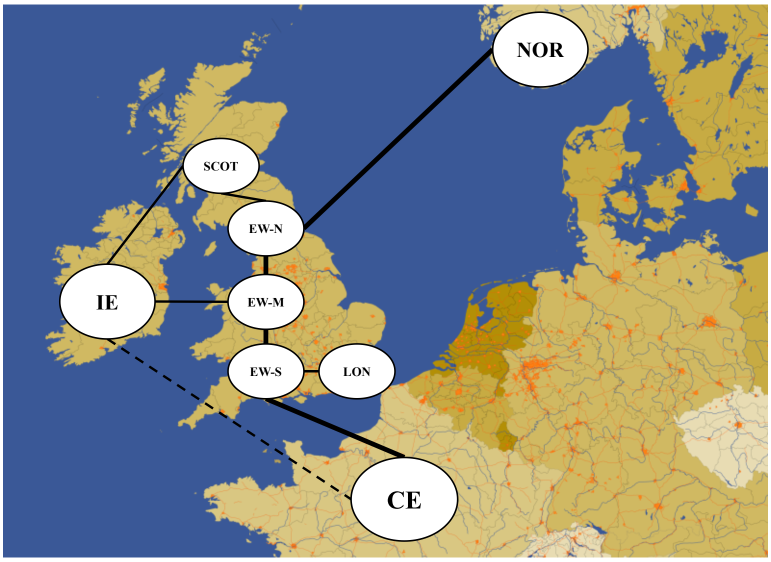

Figure 5.2. The simplified topology of the interconnected GB transmission network.

Attention is given to the above. The presence of gas-to-power technologies is considered through hydrogen-fuelled generation. All the generation and P2G capacity are quantified in each macro-region, and the market penetration of two kinds of vehicles are also optimised under the 30 g/kWh and 10 g/kWh carbon targets.

On the demand side, the non-heat electricity demand is sourced from the National Grid. The maximum non-heat electricity demand is estimated at 72 GW, while the minimum non-heat electricity demand at 19 GW, with the annual non-heat electricity demand of 274 TWh. The heat demand and the COP of ASHP are illustrated in Figure 5.3. In order to deal with RES uncertainty and achieve the redundancy of the planning to handle extreme operational conditions, considering an extreme day with 20% higher daily heat demand than the day with the highest heat demand and zero RES output.

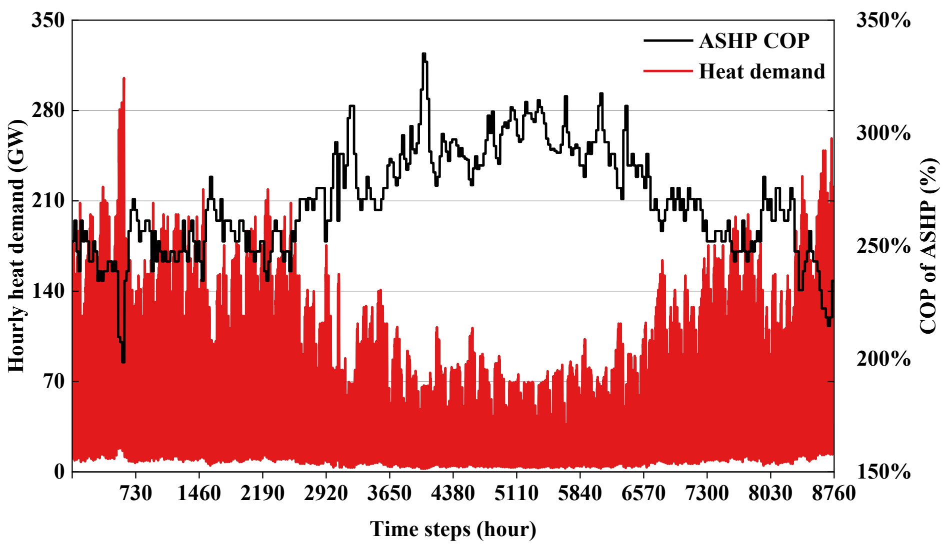

Figure 5.3. Hourly heat demand and COP of ASHP.

The following series of case studies in different scenarios (as listed in Table 5.1) are run using the proposed model.

Table 5.1. Description of different scenarios and cases.

Scenarios	Description	Cases	Description
Reference	No hydrogen integration for both the power and transport sectors, and all transport demand is electrified.	REF-EV	Transport demand is electrified without smart charging.
		REF-Smart EV	Transport demand is electrified with smart charging.
Hydrogen-to-electricity	Hydrogen is only used for the fuel of hydrogen-fuelled generation in the electricity sector.	H2GEN	Only the hydrogen-fuelled generation is integrated, and transport demand is electrified without smart charging.
Hydrogen-to-mobility	Hydrogen is only used to supply the domestic	HFCV	All transport demand is decarbonised using

	transport sector (i.e., light vehicles) in GB.		hydrogen.
		Combined	All transport demand is supplied through Smart EV and HFCV.
Combined hydrogen-to-electricity and mobility	Hydrogen is used for both the electricity and transport sectors.	OPT-EV	The model is used to optimise the proportion of transport fleets that are decarbonised using EV or HFCV.
		OPT-Smart EV	Similar to the OPT-EV case, but with smart charging for EV.

5.3. Case Studies

This section presents a series of case studies to answer RQ2 for this thesis. In addition, this chapter discusses several specific research questions related to RQ2, which can be summarised as follows:

- Quantify the economic performance of different decarbonisation strategies for the integrated electricity and transport sectors involving P2G integration under different carbon targets.
- Analyse the electricity sector capacity and generation mix and the deployment of hydrogen infrastructures in different scenarios.
- Identify the key factors affecting the penetration of different types of vehicles.

5.3.1. Economic Performance of Each Scenario

This section compares the economic performance of different cases under different carbon targets. Figure 5.4 shows the whole system annual cost for each scenario under 30 g/kWh and 10 g/kWh carbon targets, respectively.

The REF-Smart EV case enhances flexibility by shifting the charging period from peak to off-peak conditions. This mitigates the need to reinforce the electricity network and reduce the low-carbon generation investment and electricity system operating cost. The flexibility provided by 80% penetration level of smart charging minimises the cost by £4.7 bn/year compared to the REF-EV case.

The integration of hydrogen-fuelled generation can bring £3.2 bn/year cost-savings compared to the REF case. The presence of the P2G facility can absorb excess wind power energy to promote the utilisation of wind power energy, thus bring more investment on wind power generation. The hydrogen-fuelled generation can replace the conventional low-carbon generation like gas-ccs generation, reducing the electricity sector's operation cost.

In the HFCV case, assuming the efficiency of HFCV is 0.25 kWh/km, the decrease in the cost of electricity generation is partially offset by the cost of hydrogen infrastructure and fuel costs. The cost of low-carbon generation is reduced, as P2G facilitates the integration of RES. The use of HFCV also mitigates the need to reinforce the distribution network. The overall annual system cost of the HFCV case is £19.1 bn/year under 30 g/kWh carbon target.

The combined EV and HFCV (Combined) bring further cost-saving. The total system cost is £17.4 bn/year under the 30 g/kWh carbon target. In the combined hydrogen-to-power and mobility scenario, the presence of P2G promotes the penetration of renewable energy, leading the investment cost on RES to increase significantly.

Meanwhile, hydrogen to be an alternative fuel of low-carbon generation fulfil the same functionality of conventional low-carbon generation (e.g., nuclear and gas-ccs) with lower cost. Introducing HFCV into the transport sector will mitigate the need for reinforcing electricity distribution network, thus leading the annual cost of the OPT-EV (£18.2 bn/year) lower than H2GEN (£21.2 bn/year) and HFCV (£20.9 bn/year), and the annual cost of the OPT-Smart EV (£16.3 bn/year) lower than the Combined case (£19.0 bn/year). When the carbon target tights to 10 g/kWh, more integration of low-carbon power generation, renewable energy and hydrogen is needed to meet the more stringent carbon target. Further cost-savings are achieved in all cases.

In summary, hydrogen should be integrated into various energy sectors to leverage its sectoral coupling and bring more cost-savings.

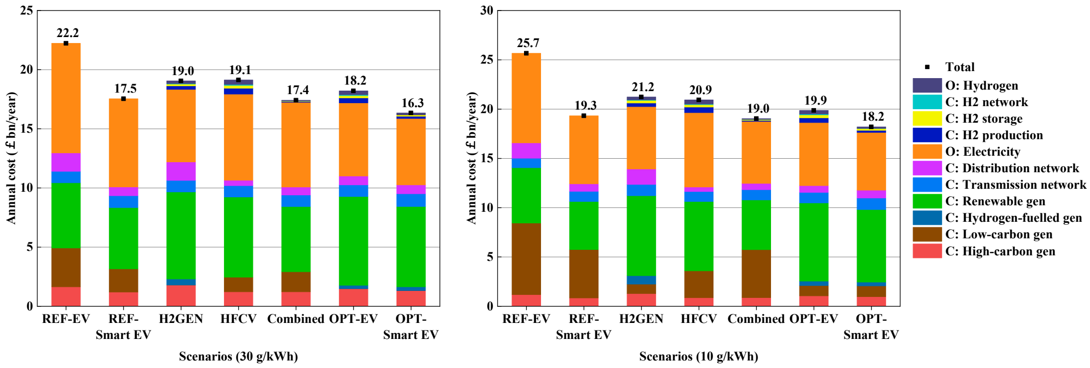

Figure 5.4. Annual system cost of different cases under 30 g/kWh (left) and 10 g/kWh (right) carbon targets.

5.3.2. Electricity Sector Portfolio of Each Scenario

Different decarbonisation strategies will reshape the electricity sector potentially. This subsection compares the capacity and annual electricity generation mix between different cases under given carbon targets.

Figure 5.5 shows the portfolio of electricity generation capacity in all cases under the 30 g/kWh carbon target. The REF-Smart EV reduces the requirement of electricity generation capacity. The hydrogen-fuelled generation reduces electricity sector emissions and facilitates the integration of variable low-carbon generation such as wind and PV. The wind capacity increases from 32.5 GW in REF to 42.8 GW in H2GEN under the 30 g/kWh carbon target. This increase allows a reduction in high-cost conventional low-carbon generation, e.g., nuclear and gas-ccs. The HFCV strategy with 0.25 kWh/km efficiency replaces the EV 0.20 kWh/km efficiency in the transport sector, which reduces the pressure of capacity expansion in the electricity sector. Based on the HFCV case, the combined case reduces the overall generation capacity due to the presence of the smart EV with an 80% penetration level. In the combined hydrogen-to-electricity and mobility scenario, the hydrogen-fuelled generation replaces nuclear and gas-ccs. The combination of HFCV and EV make the generation capacity less than the H2GEN case.

For the annual generation, the annual generation of gas-ccs reduces in all cases. The use of P2G facilities drives the system's ability to integrate RES, allowing excess RES to be stored cost-effectively through H2S facilities, thereby reducing the curtailment rate of renewable wind and solar energy. It is worth noting that the annual wind power generation can reach 73% in the OPT-EV case due to the integration of renewables facilitated by P2G.

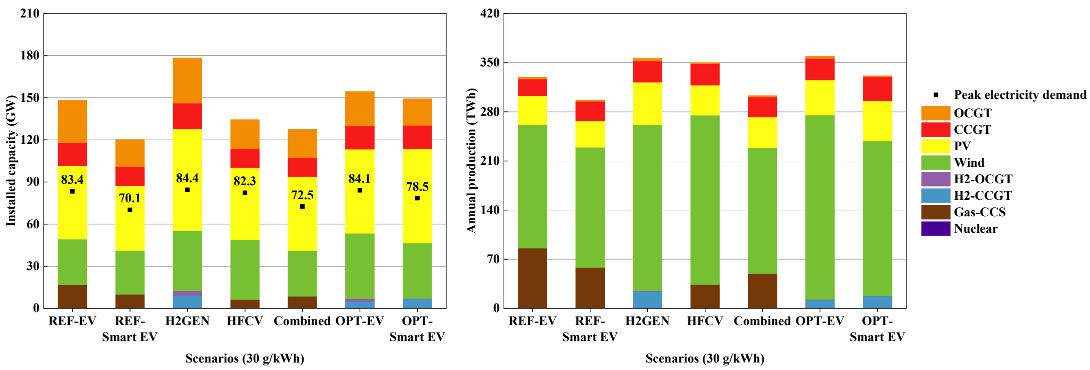

Figure 5.5. The installed capacity of electricity generation technologies (left) and electricity generation (right), as well as the peak electricity demand under 30 g/kWh carbon target.

When the carbon target tights to 10 g/kWh, the generation capacity and production mix are illustrated in Figure 5.6, respectively. To achieve the more demanding carbon target, the capacity of high-carbon generation decreases and RES generation capacity increases compared to their capacity under the 30 g/kWh carbon target. It is worth emphasising that without hydrogen-fuelled power generation, firm low-carbon generation such as nuclear power is even more critical to decarbonising the energy system under the more challenging carbon target.

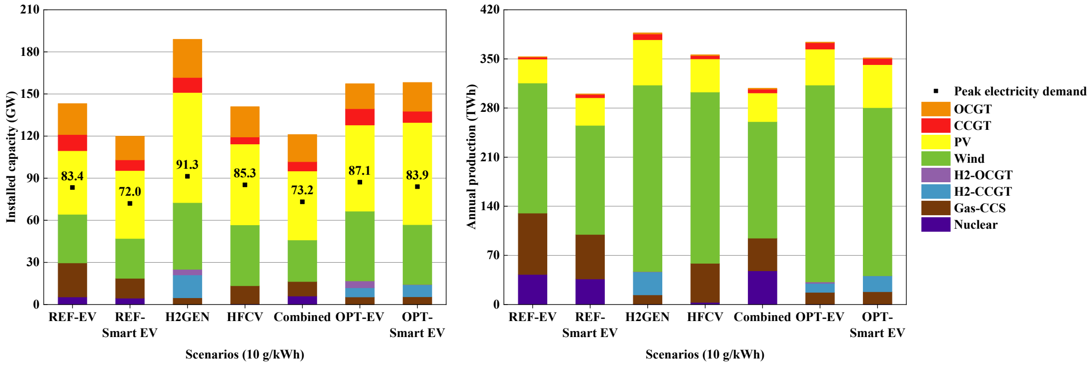

Figure 5.6. The installed capacity of electricity generation technologies (left) and electricity generation (right), as well as the peak electricity demand under 10 g/kWh carbon target.

5.3.3. Hydrogen Supply System Structure of Each Scenario

The hydrogen supply system structure under different carbon targets, including the capacity of EL, H2S and annual hydrogen demand in different cases, is illustrated in Table 5.2 and Table 5.3. It is observed that the capacity of the EL and H2S both increases in all cases when the carbon target becomes tighter. That can be explained by the P2G facility can promote the integration of wind power by absorbing excess wind power to convert it to another energy form (e.g., hydrogen fuel). In the H2GEN case, due to the electricity production from hydrogen-fuelled power generation increases under 10g/kWh carbon target, the annual hydrogen production increases from 43.5 TWh to 57.0 TWh.

In the HFCV cases, the hydrogen demand driven by HFCV is constant, so the hydrogen supply structures under different carbon targets are similar. When Smart EV and HFCV strategies are applied to decarbonise the transport sector (Combined), the P2G capacity, H2S facilities, and annual hydrogen demand all decrease significantly compared to H2GEN and HFCV. It can be explained by the HFCV with 0.25 kWh/km efficiency is still not competitive, with an 80% penetration level of smart EV under the given situation in this study.

In the combined hydrogen-to-electricity and mobility scenario, as the carbon emissions constraint becomes tighter, more renewable energy needs to be integrated into the system, increasing investment in P2G facilities to absorb excess renewable energy, leading to an increase in hydrogen demand. Simultaneously, with the rise of hydrogen demand, more H2S facilities will be deployed to balance the varied hydrogen supply and demand. In comparison to the OPT case, DSR of EV demand with the 80% penetration level cannot only provide flexibility for the electricity sector to reduce peak requirement for the electricity generation but also reduce peak hydrogen demand from 28.2 GW to 10.8 GW and 41.3 GW to 13.8 GW under 30 g/kWh and 10 g/kWh, respectively.

Table 5.2. Hydrogen supply system structure in different scenarios under 30 g/kWh carbon target.

	H2GEN	HFCV	Combined	OPT-EV	OPT-Smart EV
P2G capacity (GW)	10.1	17.4	2.3	14.5	6.6
H2S capacity (TWh)	134.0	195.7	35.7	169.2	105.8
H_2 demand (TWh)	43.5	93.6	9.1	78.4	30.8

Table 5.3. Hydrogen supply system structure in different scenarios under 10 g/kWh carbon target.

	H2GEN	HFCV	Combined	OPT-EV	OPT-Smart EV

P2G capacity (GW)	12.7	19.3	3.3	16.9	7.1
H2S capacity (TWh)	224.2	209.9	71.1	250.3	146.5
H_2 demand (TWh)	57.0	93.6	15.5	88.9	38.7

5.3.4. Fleets Penetration in the Transport Sector of Each Scenario

This section presents two fleets' market penetration in different cases under different carbon targets (Figure 5.7).

In the Combined case, the results show that the optimal market penetrations of EV and HFCV are 94.1% and 5.9% under the 30 g/kWh carbon target. When the carbon target tights to 10 g/kWh, the penetration of HFCV increases to 9.6% in the Combined case due to the economic advantage of hydrogen integration in the stricter carbon target scenario mentioned above.

In the combined hydrogen-to-electricity and mobility scenario, when the smart charging enables the EV, it dominates the market; otherwise, HFCV will have close to half of the market share. Hydrogen only used in the electricity sector as the fuel for generation. The ability of smart EV to provide additional system flexibility improves the integration of renewable energy, which can be used to charge EV more directly to reduce energy conversion losses.

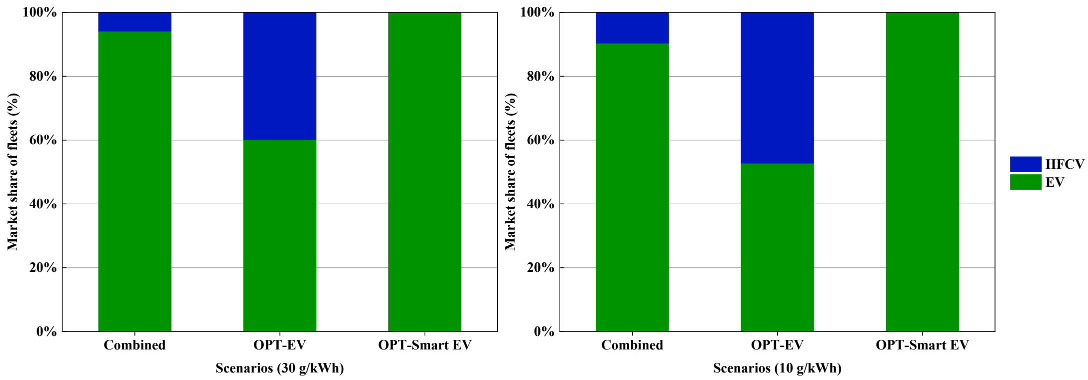

Figure 5.7. Market penetration of different fleets in different cases under 30 g/kWh (left) and 10 g/kWh (right) carbon targets.

The increasing peak load brought by electrifying transport demand can be reduced by shifting the EV charging period to off-peak through DSR. It will reduce the peak demand in the electricity sector and mitigate the need for distribution network reinforcement. This case investigates the impact of smart charging control for EV on the market penetration of fleets.

Figure 5.8 illustrates the market penetrations of EV and HFCV in a series of smart EV penetration level in the OPT-Smart EV case. It can be observed that the competitiveness of EV is highly sensitive to the smart EV penetration level. With the increased deployment of smart charging, the penetration of EV will increase. Based on the assumptions and technical data used in this study, when the smart EV penetration level increases to 70%, the EV dominates the market.

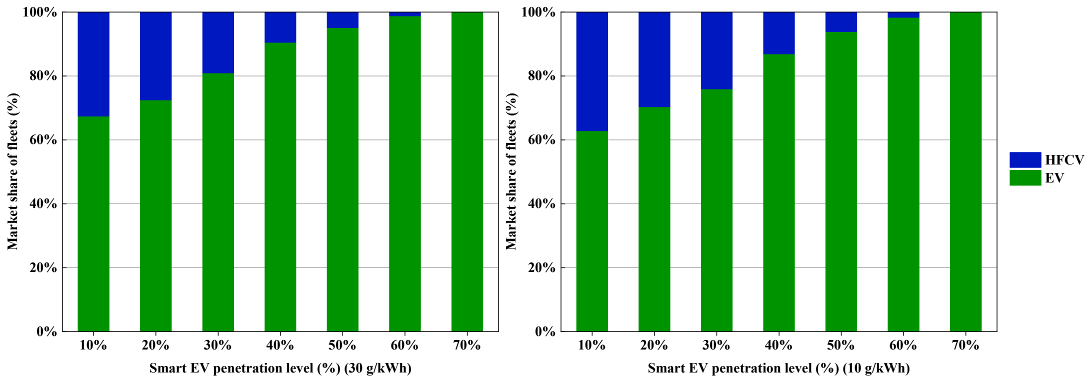

Figure 5.8. The sensitivity study on the Smart EV penetration level under 30 g/kWh (left) and 10 g/kWh (right) carbon targets.

5.4. Conclusions of the Chapter

This chapter considers the sector coupling interactions across the electricity, transport and hydrogen vectors along with the increased deployment of e-mobility or HFCV and the integration of hydrogen (from renewables) to both electricity and road transport, determining the optimal investment mixes and MES operation on the national scale.

Firstly, smart-charging EV bring flexibility to the whole system and more economic benefits than other individual decarbonisation strategies (i.e., £17.5 billion/year under 30 g/kWh carbon target). As carbon emission targets are tightened, the economic benefits become more substantial (i.e., £19.5 billion/year under 10 g/kWh carbon target). The use of HFCV for decarbonising the transport sector decreases the cost of electricity generation and distribution network reinforcement which is partially offset by the cost of hydrogen infrastructure and fuel costs. The combined case (OPT-Smart EV) demonstrate that hydrogen should be integrated into various energy sectors to leverage its sectoral coupling and bring more cost-savings.

Secondly, the decarbonisation of transport will reshape the supply structure of the electricity sector. Electrification of the transport sector will increase the electricity generation capacity requirement, but smart EV will mitigate this requirement. The presence of P2G facilitates the integration of RES generation, and alternative low-carbon generation sourced from hydrogen fulfil the same functionality of conventional low-carbon generation (e.g., nuclear and gas-ccs). The integration of P2G also increases the wind power capacity to 46.6 GW in the OPT-EV scenario under 30 g/kWh carbon target.

Thirdly, the results also demonstrate that hydrogen integration's depth increases further as the carbon target becomes tighter. When the smart EV and HFCV co-exist in the market, the DSR of EV demand not only provide flexibility for the electricity sector to reduce peak requirement for the electricity generation but also reduce peak hydrogen demand from 28.2 GW to 10.8 GW and 41.3 GW to 13.8 GW under 30 g/kWh and 10 g/kWh, respectively.

Finally, when EV and HFCV co-exist in the market, HFCV cannot compete with EV due to their lower energy efficiency. However, the simultaneous use of hydrogen in the electricity and transport sectors will boost the penetration of HFCV (i.e., 60% under 30 g/kWh carbon target). When EVs are equipped with smart charging, EV dominates the market again, the hydrogen only used in the electricity sector for the fuel of generation. It is worth highlighting that EV's penetration increases with EV's flexibility level and dominates the market when smart EV penetration levels increase to 70%. All the results are system-specific and depend on the assumptions taken.

Chapter 6. Integration of Hydrogen into Multi-Energy Systems Optimisation

6.1. Introduction

The new-found interest in hydrogen from both industry and academia has stimulated research exploring the application of hydrogen as a potential option for decarbonising major parts of the energy system. Hydrogen can play a key role alongside electricity in the low carbon economy due to its low-cost storability, flexibility, low-carbon hydrogen production technologies, and the opportunity to re-energise the gas distribution network. It is also a flexible energy vector that can be produced from various energy sources. Two sources are considered in this chapter to produce hydrogen: natural gas and electricity. Hydrogen can be used as fuel for electricity generation, fuel for HB for heating, and it can also be used to power fuel cells for transport and co-generation for electricity and heat. This feature raises important questions on how the hydrogen should be integrated with other energy systems to achieve decarbonisation targets and the importance of whole-energy system optimisation compared to the traditional silo planning approach.

The need to address these questions has triggered the development of MES modelling approaches to assess the technical and cost implications of integrating hydrogen into the overall energy system. Compared to the energy system planning approach without considering synergies between different sectors, MES, whereby different energy vectors (e.g., electricity, heat and gas, etc.) can operate in a coordinated fashion at various levels, introduces a vital opportunity to improve the system planning technically, economically, and environmentally [76]. Few hydrogen applications include HB, HFCV, and hydrogen-fuelled micro-CHP, demonstrating that hydrogen brings interaction to several sectors across the energy landscape. However, the impacts of this cross-energy vector interaction on the energy system capacity requirement and operation, primary energy demand, values, and options that hydrogen create have not been thoroughly investigated, especially in the context of MES. The benefits and the system implications of integrating a hydrogen supply chain should be identified through a whole system approach to capture complex interactions across different technologies, different energy vectors, and coordination between investment in energy infrastructure and operating decisions.

Authors propose the use of a holistic optimisation model for electricity sector investment and operation decisions to assess the value of bulk and distributed energy storages in future low-carbon electricity systems [18]. Enhancing the model in [18], the authors propose the integrated electricity and heat sectors model in [19]. The model is used to analyse the system implications and cost performance of alternative heating decarbonisation strategies, including the use of hydrogen, electrification, and hybrid HP-B. The analyses considered the interactions between electricity sectors and heat sectors. Similarly, Zhang et al. [48] quantify the benefits of integrating the heat sector, particularly district heating and the electricity sector. Through integrated planning, the flexibility that exists in the heating sector can be utilised to support the electricity sector, which otherwise has to count on the flexibility measures within the electricity sector itself. The series of case studies demonstrate that the DHN and the application of TES would enhance the overall energy system's flexibility, thus delivering substantial cost savings to meet the carbon target. Chaudry et al. [77] propose a combined gas and electricity sectors optimisation model to solve short-term operation problems. The model links two energy sectors through gas turbine generation. The proposed combined gas and electricity sectors model has demonstrated its value for assessing the consequences of the failure of vital facilities.

Previous research on integrating hydrogen in the overall energy system has focused chiefly on its industrial production, transmission, and distribution [78]. Authors design a future hydrogen supply chain that covers production, storage, and distribution for the UK transport demand. A few previous studies consider the interactions of hydrogen with other energy sectors [55-57]. The optimisation only considers the transport demand supplied by hydrogen. However, the broader electricity sector's design and operation and other hydrogen production processes are not considered. Samsatli et al. [79] propose a comprehensive spatiotemporal MILP model to optimise the integrated electricity and hydrogen value chains to supply the space and water heating demand in GB. The impacts of P2G facilities in the integrated electricity and gas sectors are analysed in [80], proving the flexibility and effectiveness of P2G facilities. In [81], a power-to-hydrogen-and-heat scheme is proposed, in which the power-to-heat and power-to-hydrogen processes are coupled through adopting the heat recovery from the P2G process. The synergy among the electricity sector, the transport sector, and the hydrogen sector are analysed in [82], but the heat sector is not considered.

This chapter proposes an electricity–heat-transport–hydrogen economic optimisation with environmental constraints at the national level, which simultaneously considers the infrastructure capital expenditures and whole system operative expenditures, thus meeting the specific carbon targets at a lower whole system cost.

The outline of the remainder of this chapter is organised as follows: Section 6.2 presents the system implication and scenario setting of this study. In Section 6.3, a series of case studies are performed to compare the advantages and disadvantages of adopting G2G and P2G individually with the system without hydrogen integration in different carbon scenarios. The conclusions are provided in Section 6.4.

6.2. System Description and Scenario Setting

Interactions occur through the energy conversion between different energy carriers to supply energy demand and ensure optimal and secured operation. There are numerous interactions between different energy sectors in this study, as shown in Figure 6.1. GHR-CCS and EL are the technologies for the G2G and P2G processes. GHR-CCS and EL link hydrogen with the natural gas and electricity sectors together, respectively. The other existing interactions are similar to those mentioned in Figure 2.1 and will not be repeated for the sake of brevity.

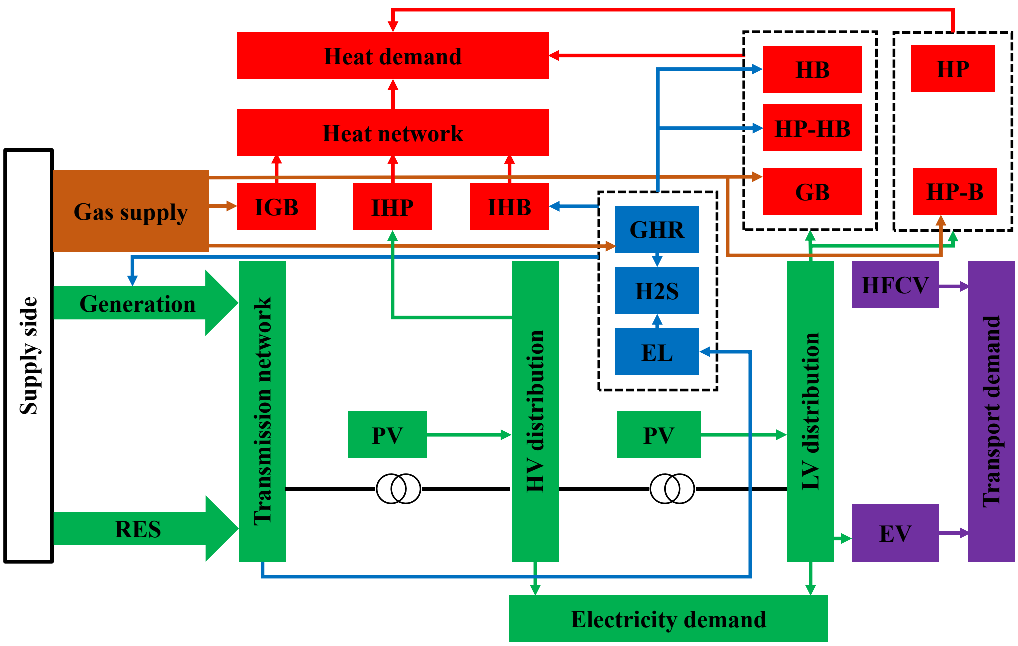

Figure 6.1. The possible interaction of integrated electricity–heat–transport–hydrogen system.

This chapter's proposed scenarios are also tested and analysed in the simplified GB system presented in Chapter 5. The three main energy conversion pathways in the MES of this study are illustrated in Figure 6.2. Based on the proposed MES's existing energy conversion pathways, four scenarios are compared under 30 Mt and 10 Mt carbon targets. The four scenarios are described in Table 6.1.

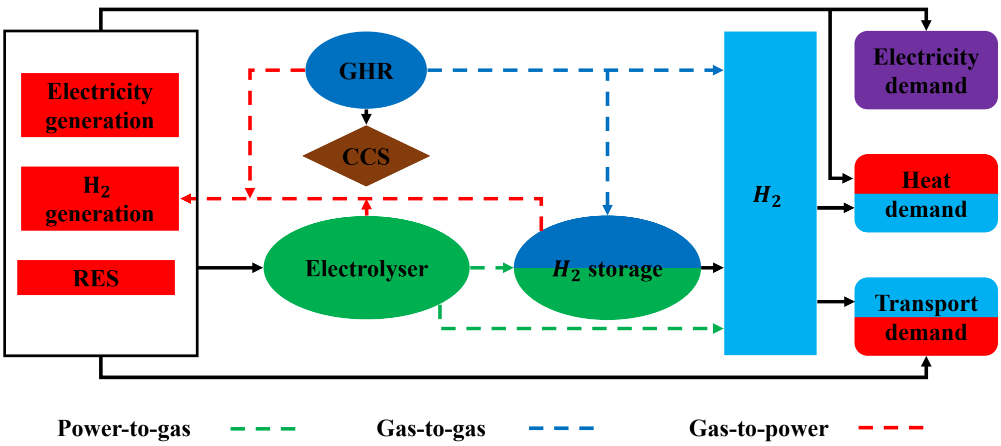

Figure 6.2. The three main energy conversion pathways in the proposed MES.

Table 6.1. Description of different scenarios in the integrated electricity–heat–transport–hydrogen system.

Scenarios	Description
REF	This is the counterfactual scenario assuming that there is no hydrogen integration across the whole energy system.
P2G	Hydrogen is integrated into the energy system, which is produced only by the P2G process (i.e., EL).
G2G	Similar to the P2G scenario, but hydrogen is produced only by the G2G process (i.e., GHR-CCS).
OPT	The model was used to optimise the capacity of different hydrogen production processes (G2G and P2G).

6.3. Case Studies

This section presents a series of case studies to answer RQ3 for this thesis. In addition, this chapter discusses several specific research questions related to RQ3, which can be summarised as follows:

- Quantify the economic benefit of different hydrogen production technologies integration for the integrated electricity, heat and transport sectors under different carbon targets.
- Analyse the deployment of different technologies in the electricity, heat, transport and hydrogen sectors under different carbon targets.
- Identify the key factors that affect the penetration of different hydrogen production technologies.

6.3.1. The Economic Benefit of Hydrogen Integration

This section compares P2G, G2G, and OPT's economic performance by comparing the costs against the costs of the counterfactual scenario (REF). Figure 6.3 and Figure 6.4 show the whole system cost savings for each scenario under two different carbon targets. The G2G process is identified as the most cost-effective hydrogen production technology under the 30 Mt carbon target, reducing the cost by £3.9 bn/year (6.5%). The P2G scenario can bring £2.1 bn/year (3.8%) cost-savings. The OPT scenario brings further cost savings up to £6.6 bn/year (11.2%) by optimally combining the portfolio of hydrogen production technologies. In the heat sector, the use of hybrid heating technology, which is based on high COP HP, to supply the baseload of heat demand while providing the flexibility to use hydrogen to supply peak demand or when there is scarcity in the low-carbon electricity generation output.

The flexibility provided by the hydrogen sector can reduce the total electricity generation capacity requirement from 71 GW to 53 GW in the G2G scenario and reduce electricity operation cost by £5.1 bn/year under 30 Mt carbon target. Integration of hydrogen also allows hydrogen-fuelled electricity generation to displace higher cost low-carbon technologies such as nuclear and gas-ccs while supporting better integration of renewables by providing flexibility and balancing fluctuating renewable energy in the system. It is worth noting that under the P2G scenarios, the investment in renewable energy, especially wind power, increases significantly due to the P2G facilities, which can help integrate renewable energy, as its electricity consumption can be adjusted to follow the renewable generation. The excess of renewable energy can be stored cost-effectively and used when the renewable output is low.

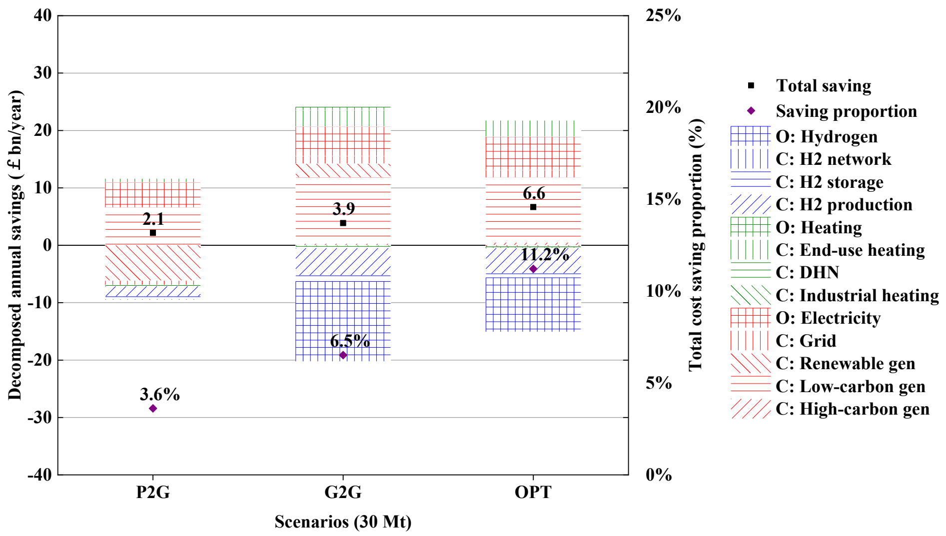

Figure 6.3. Saving from hydrogen integration under 30 Mt carbon target.

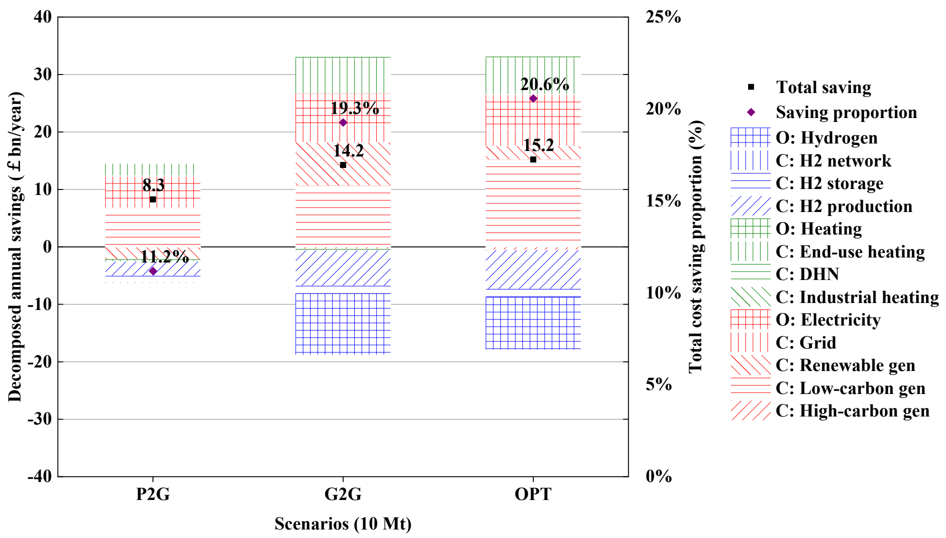

Figure 6.4. Saving from hydrogen integration under 10 Mt carbon target.

Most of the benefits gained in the heat sector through the deployment of HB is driven by the reduced investment in the end-use heating appliances and industrial heating appliances under 30 Mt and 10 Mt carbon targets, respectively, which also further achieved the cost-savings in the distribution network reinforcement due to the electricity peak demand reduction that is compensated by hydrogen-based heat.

The increased hydrogen integration cost is mainly from the hydrogen system, which is dominated by the hydrogen system's operation cost in the G2G and OPT scenarios. The increased cost in the P2G scenarios mainly comes from the hydrogen production investment. The carbon target influences the economic benefit of the integration of the hydrogen system. In the 10 Mt case, due to the zero-emission characteristics of the P2G process, it plays a more important role in the low-carbon scheme. However, the G2G process still has an economic advantage, especially saving on electricity infrastructure investment (e.g., generation and grid network). The OPT scenario's annual saving under a carbon target of 10 Mt increased to 15.2 bn/year (20.6% of total cost in the REF scenario).

6.3.2. Impact of Hydrogen Integration on the Electricity Sector

The integration of hydrogen into the system makes the application of hydrogen-fuelled electricity generation advantageous, thus reshaping the electricity system potentially, and using HB as the main low-carbon heat source reduces the electricity peak demand and the need for the new electricity system capacity compared with the system capacity needed if the heat is decarbonised through electrification only. This section compares the capacity and annual electricity generation mix between different scenarios under given carbon targets.

Figure 6.5 and Figure 6.6 show the portfolio of electricity generation capacity and the annual electricity production in each scenario under different carbon targets. It can be observed that the G2G process can reduce the capacity requirement of electricity generation significantly (and other electricity infrastructure, e.g., network) compared to

P2G. The choice of hydrogen production pathway will have significant implications for the electricity sector. The hydrogen-fuelled generation replaces a large part of the low-carbon generation because sufficient flexibility can be provided from the hydrogen-fuelled generation without carbon emissions. The more expensive source of flexibility like gas-ccs is not necessary. The high-carbon generation capacity reduction is driven by the enhanced flexibility and presence of hydrogen-fuelled generation. P2G can significantly promote wind power integration as the EL can absorb excess wind power, which improves wind power utilisation. The availability of firm low carbon generation such as nuclear is more critical for energy system decarbonisation under a more demanding carbon target. It is worth emphasising that the carbon emissions from the G2G process limit the large-scale deployment of hydrogen-fuelled generation in the electricity system.

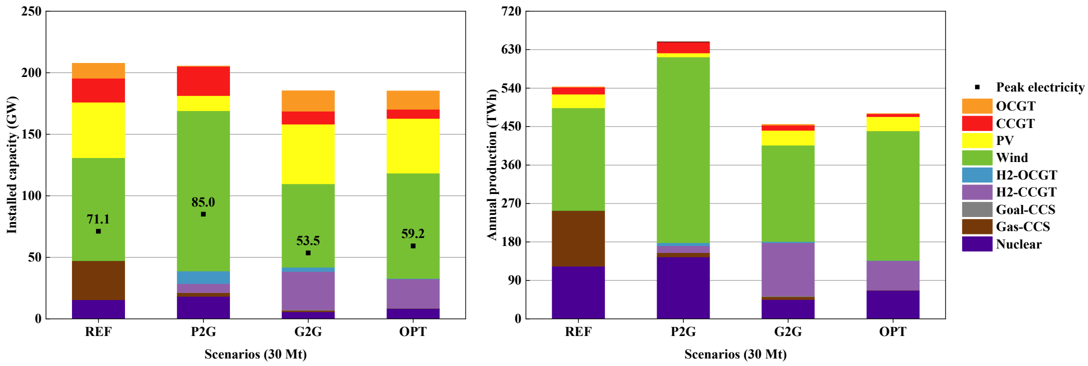

Figure 6.5. The installed capacity of electricity generation technologies (left) and electricity generation (right), as well as the peak electricity demand under 30 Mt carbon target.

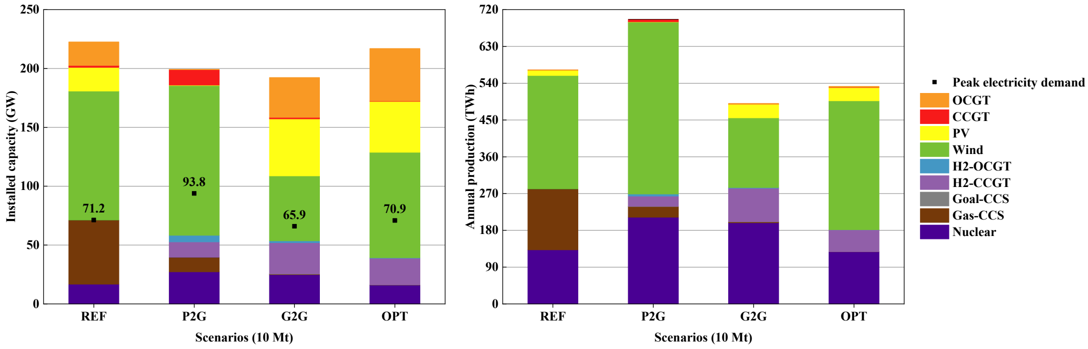

Figure 6.6. The installed capacity of electricity generation technologies (left) and electricity generation (right), as well as the peak electricity demand under 10 Mt carbon target.

As for the annual electricity production in each scenario, where the annual wind power generation in the REF cases were 240 TWh and 278 TWh under 30 Mt and 10 Mt carbon targets, respectively, it can be observed that the annual wind power generation in the P2G cases increased to 435 TWh and 421 TWh, which were 67% and 61% of total generation under the 30 Mt and 10 Mt carbon targets, respectively. The increased system ability to integrate wind is driven by using the P2G facility, which allows the excess renewable energy to be stored cost-effectively via H2S, thus reducing the curtailment rate of wind power. The difference in the annual generation mix is further reflected by the increased generation of nuclear power in the G2G cases compared with the P2G cases, where the nuclear power generation in the G2G cases is notably higher than in the case of P2G as well as its capacity. The main reason is that the G2G facility cannot help integrate more renewable energy, giving priority to nuclear power as low-carbon power generation. Meanwhile, the relatively high carbon emission of GHR-CCS increases the integration costs of a hydrogen system under a 10 Mt carbon target. Thus, the installed capacity of hydrogen-fuelled generation and its production decrease.

6.3.3. Impact of Hydrogen Integration on the Heat Sector

The mix of heating technology and annual heat production under different carbon targets are shown in Figure 6.7 and Figure 6.8. The national DHN pathway only contributes a small part of heat demand in each scenario under both carbon targets due to the expenditure associated with heat networks deployment.

In a system with hydrogen, the heating pathway is shifted from end-use HP-B to end-use HP-HB, which drives less investment in the electricity sector, as can be derived from Figure 6.5 and Figure 6.6. It is worth noting that hybrid HP-HB can dominate the heating market, which is up to 73% in the OPT scenario when the carbon target becomes tighter (10 Mt). It is worth noting that despite the relatively larger installed capacity of the NGB, the HP provides more heating demand than the NGB. This can be explained by the fact that the COP of the ASHP is sensitive to the ambient temperature, so that the overall efficiency of the EGB is higher than that of the ASHP on extremely cold days, and only a portion of the ASHP is in operation while the rest of the heat demand is met by the NGB, which leads to the oversized deployment of the NGB. In general, the optimised capacity of NGB in hybrid HP-B is a balance between the reduced energy efficiency of ASHP due to temperature variations and the increased investment cost of NGB.

Hydrogen integration also has a notable impact on the annual heat production mix. It can be observed that HP supplies the baseload while NGB only provides a little part of heat demand during the peak load due to its emissions and less flexibility when the hydrogen integration is not enabled, or its integration is not cost-effective (e.g., the P2G pathway). In the G2G case, the heat provided by HB increases to 23% and 27% under the 30 Mt and 10 Mt carbon targets, respectively. In the OPT scenario, the P2G process brings zero-emission hydrogen production, which offsets the carbon emissions from the G2G process and makes HB production increase further to 29% under a 10 Mt carbon target. Generally, the P2G process is necessary to offset the hydrogen sector's carbon emissions under a demanding carbon target.

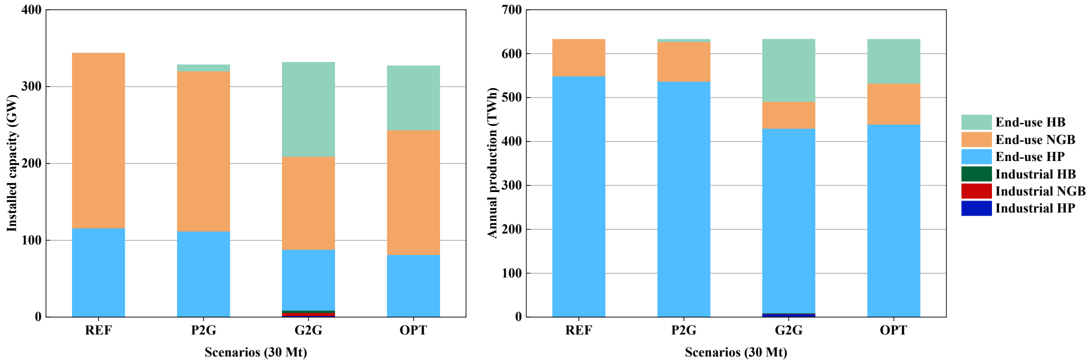

Figure 6.7. The installed capacity of heating technologies (left) and heat production (right) under 30 Mt carbon target.

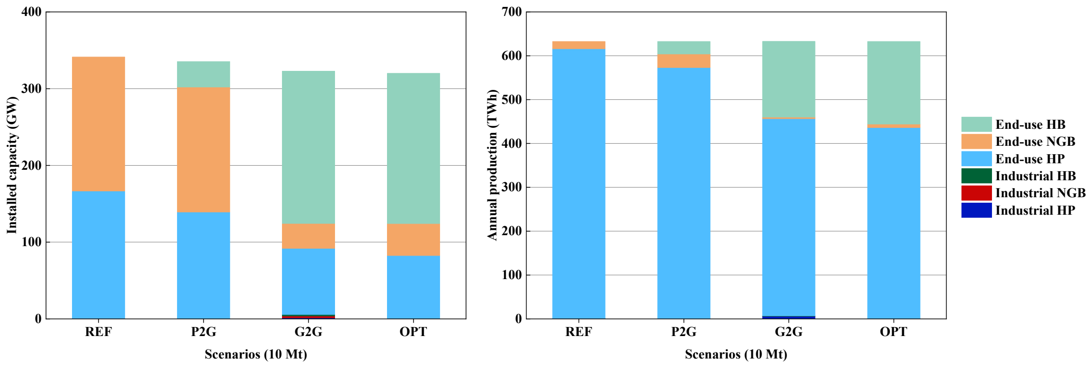

Figure 6.8. The installed capacity of heating technologies (left) and heat production (right) under 10 Mt carbon target.

6.3.4. Impact of Hydrogen Integration on the Transport Sector

Figure 6.9 shows the proportion of each transport technology in different scenarios under different carbon targets. When the carbon target is 30 Mt, in the P2G scenario, EV still accounts for the most market. If hydrogen production shifts from P2G to G2G or a combined pathway, the cost of hydrogen integration will be reduced to become more competitive in the transport sector, allowing HFCV to dominate the transport market. However, when the carbon target is tightened to 10 Mt, EV takes back the domination position due to the hydrogen production process, which is less competitive. Only through least-cost hydrogen production (OPT), the HFCV can occupy a 35% market share. In summary, from the whole system point of view, the deployment of HFCV is sensitive to the costs of hydrogen and lower costs of hydrogen drive investment in HFCV. Emission is another factor affecting the deployment of HFCV, and the P2G process is necessary for the development of HFCV due to its zero-emission feature.

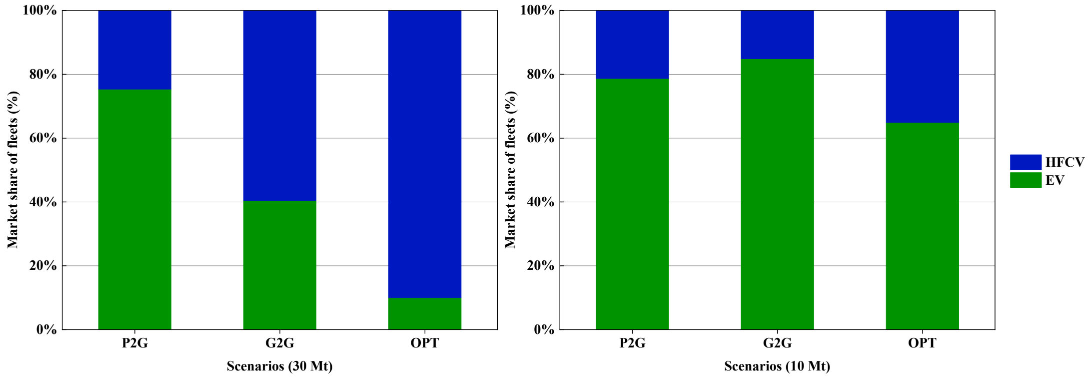

Figure 6.9. Market penetration of different fleets in different scenarios under 30 Mt (left) and 10 Mt (right) carbon targets.

6.3.5. Impact of Hydrogen Integration on Carbon Emissions

The integration of the hydrogen system will influence the decarbonisation strategies of other energy sectors. Figure 6.10 shows the total carbon emissions of each energy sector in each scenario. The integration of the hydrogen sector shifts the carbon emissions from the electricity sector to other energy sectors in all the P2G, G2G, and OPT scenarios. Decarbonisation of the heat sector under a 30 Mt carbon target will require a higher integration of low-carbon heat supply technologies (HP and HB) and increased investment cost in the electricity and hydrogen sectors. When the carbon target is set strictly to 10 Mt, the high hydrogen integration cost of P2G also increases the decarbonisation cost in the electricity and heat sectors. When more economical hydrogen production methods (G2G and OPT) are adopted to produce hydrogen, hydrogen penetration in the electricity and heat sectors increases further. The carbon emissions of the whole system mainly come from the hydrogen sector due to a higher share of hydrogen-fuelled electricity generation, and HB replaces most of the NGB. This case study indicates that hydrogen integration may shift the carbon emissions from the electricity and heat sectors to the hydrogen sector since it is more cost-effective to decarbonise the energy through hydrogen. It is worth noting that the carbon emissions of the heat sector are far lower than the other energy sectors in the G2G and OPT scenario with the 10 Mt carbon target due to the massive deployment of HB, indicating that hydrogen integration will play an important role in the cost-effective transition towards a zero-carbon future energy system.

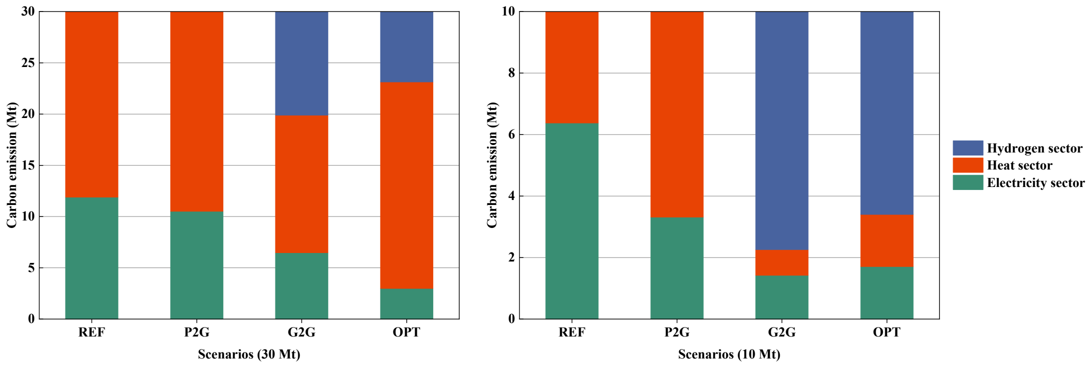

Figure 6.10. Carbon emissions mix under different carbon targets.

6.3.6. Hydrogen Production Technologies Deployment

The deployment of an EL requires more electricity generation capacity investment, which increases the 34.4 GW and 52.1 GW peak demand under 30 Mt and 10 Mt carbon targets in the P2G scenario, respectively. Table 6.2 shows that GHR-CCS dominated the hydrogen production technology due to the economic advantages of GHR, as mentioned in the above case. However, the capacity of the EL increases when the carbon target becomes stricter because of its zero-carbon emissions feature. In terms of the annual hydrogen production, when the carbon target changes from 30 Mt to 10 MT, the annual hydrogen production of the EL increases in all scenarios. In contrast, the annual hydrogen production of GHR-CCS decreases in the G2G scenario. The share of GHR-CCS falls in the OPT scenario, mainly due to the need to meet a stricter carbon target.

Table 6.2. Capacity and the annual output of different hydrogen production technologies in different scenarios under different carbon targets.

Scenarios		Capacity (GW)		Production (TWh)	
		EL	GHR-CCS	EL	GHR-CCS
30 Mt	P2G	19.3	0	93.4	0
	G2G	0	79.7	0	461.4
	OPT	9.1	60.1	25.5	313.5
10 Mt	P2G	27.2	0	128.3	0
	G2G	0	103.0	0	353.5
	OPT	11.4	95.5	39.6	301.3

6.3.7. The Relation Between the P2G facility and Wind Power

In this system, aside from P2G being able to absorb the excess wind power to integrate more wind power into the system, the P2G facility can also offer a flexible load, thus providing ancillary services like frequency response through the interrupted operation, which also increases the wind power integration potentially. As shown in Figure 6.11, P2G can promote wind power integration, and G2G plays the opposite role.

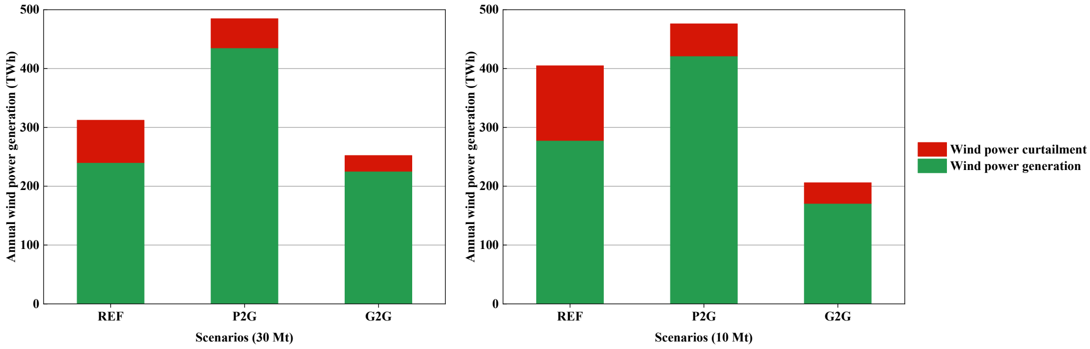

Figure 6.11. The wind power generation and curtailment in different scenarios under different carbon targets.

6.3.8. Sensitivity Analysis of Wind Power Capital Cost

Figure 6.12 illustrates the wind power capacity and hydrogen production technology capacity mix in a series of wind power capital cost scenarios under the carbon targets of 30 Mt and 10 Mt. It can be observed that the competitiveness of the P2G facility is highly sensitive to the variation of wind power capital cost, while the penetration of the P2G facility is much more robust under the stricter carbon targets. In terms of G2G capacity, with the increase in capital costs of wind power, less wind power will be installed; consequently, the G2G capacity will need to increase to achieve the overall carbon target.

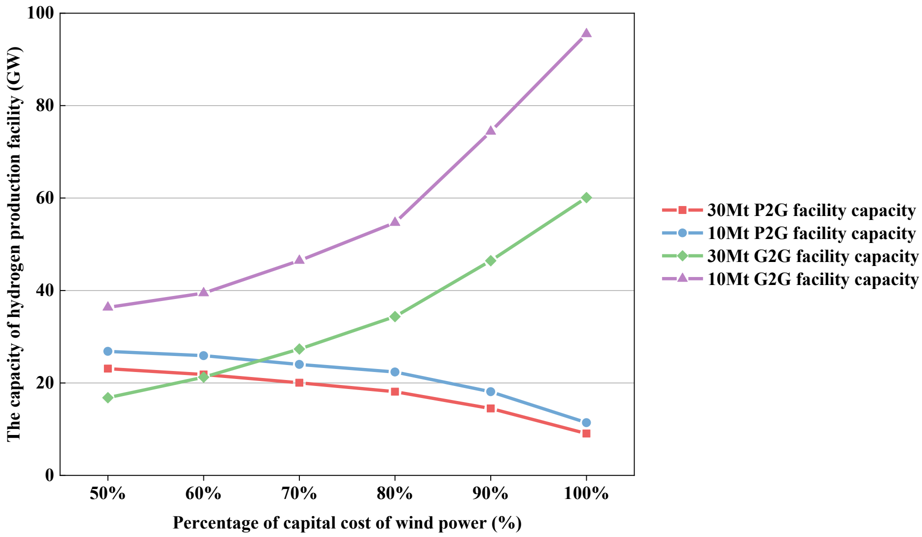

Figure 6.12. The sensitivity study on the capital cost of wind power.

6.3.9. Sensitivity Analysis of Natural Gas Price

As mentioned before, the cost of large-scale hydrogen integration is dominated by the operation cost of the hydrogen sector, which is highly sensitive to the natural gas price. The above case studies are based on the natural gas price of 67 p/therm. The G2G process has a dominating role in the integration of hydrogen in the OPT scenario. As shown in Figure 6.13, when the natural gas price drops by 50% to 33.5 p/therm, the overall integration cost of the G2G facilities will be reduced due to the decrease of the natural gas price, which will weaken the integration of P2G facilities. On the contrary, if the price of natural gas increases by 50% to 100.5 p/therm, P2G capacity will increase, and G2G capacity will decline due to the increased operating cost of the G2G process. However, the capacity of G2G is still higher than that of P2G due to the higher demand for hydrogen integration under the 10 Mt carbon target. The G2G still has an economic advantage compared to P2G. In terms of hydrogen production, the rise of natural gas prices has significantly reduced the production of G2G. In contrast, the production of P2G is slowly rising.

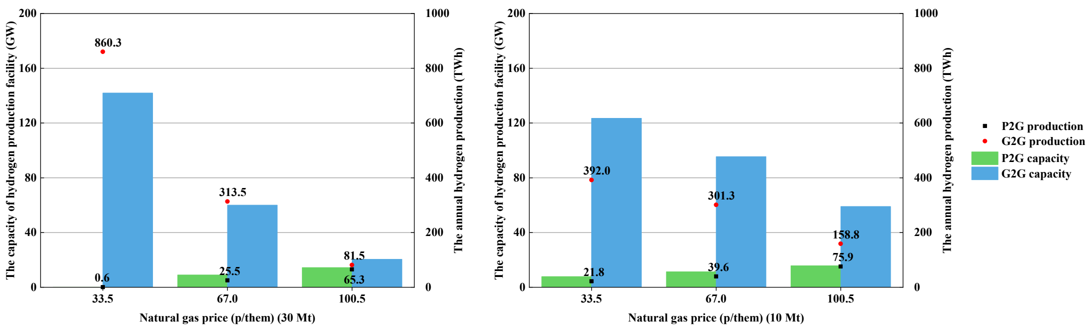

Figure 6.13. The sensitivity study on the natural gas price.

6.4. Conclusions of the Chapter

This chapter investigates the economic performance and impact of different hydrogen production technologies on the planning and operation of integrated electricity, heat and transport sectors. A series of cases studies are conducted to optimise the decarbonisation strategies for the whole energy system while assessing hydrogen integration values.

Firstly, the studies demonstrate that hydrogen integration through the G2G process brings more economic benefits than the P2G process, which can deliver £3.9 bn/year and £14.2 bn/year cost savings the 30 Mt and 10 Mt carbon targets, respectively. The OPT pathway can offset the carbon emissions from the G2G process and achieve further cost savings.

Secondly, the results also clearly demonstrate the electricity side changes driven by the different hydrogen integration strategies. The G2G process can reduce the total electricity generation capacity requirement from 71 GW to 53 GW. The P2G can increase the integration of wind power capacity from 83 GW to 130 GW under the 30 Mt carbon target.

Thirdly, the integration of hydrogen will promote the deployment of HB, which, combined with HP, will dominate the heating market, which is up to 73% in the OPT scenario under the 10 Mt carbon target. From the perspective of the transport sector, the development of HFCV is highly related to the integration cost of the hydrogen sector, especially in the demanding carbon scenario. The HFCV can occupy the 90% market share in the OPT scenario under the 30 Mt carbon target. However, when the carbon target becomes tighter (10 Mt), the integration cost of the hydrogen sector increases and the market share of HFCV will decrease to 35% in the OPT scenario.

Finally, a series of sensitivity studies indicate that the P2G facility's integration is highly sensitive to the wind power capital cost. The higher cost of wind power will weaken the integration of P2G. The G2G facility is susceptible to the natural gas price. Higher natural gas price will undermine the G2G integration. It is worth mentioning that all the results are system-specific and depend on the assumptions taken.

Chapter 7. Multi-Year Multi-Energy System Optimisation Model

7.1. Introduction

In Chapter 3, a single-year MES optimisation model is proposed to evaluate different decarbonisation strategies with minimum cost. The single-year framework sets in either the present or the future, obtaining the optimal system without being constrained by requirements in the previous periods. It assumes a non-evolving capital structure and focuses instead on the system's operational dynamics, which is not adequately secure the validity and robustness of the investment decisions to be implemented. It typically embeds considerable temporal and technical detail, such as individual generation plant and transmissions lines.

In the present chapter, a multi-year MES optimisation model casts over one or more decades, attempting to encapsulate the system's structural evolution and are used to investigate capacity expansion of energy system and transition issues. The model presented in this chapter covers all the components of the framework described in Chapter 2 and can be divided into five main parts: the electricity sector, the heat sector, the transport sector, the integration of hydrogen, and the integration of NETs.

Electricity sector decarbonisation: The reduction in electricity sector carbon emissions has been driven by a shift away from using high-carbon generation towards low-carbon and RES generation. The existing literature is rich in addressing the long-term electricity sector expansion at the national level considering the carbon emission targets. Koltsaklis et al. [83] present a multi-period long-term generation expansion model to minimise the total electricity sector cost under several economic and environmental constraints. The same authors integrate the unit commitment problem with the generation expansion problem considering hourly resolution [84]. Cheng et al. [85] present a multi-period, multi-regional optimisation model for the long-term development of China’s electricity sector considering regional variations in availabilities of resources and inter-region power transmission line capacity. The operational flexibility and the impacts of electrification of heating and transport should be considered in electricity sector planning since the RES is characterised by inherent intermittency as well as the electrification of heating and transportation such as HP, EV, will also reshape the electricity generation mix and bring additional reinforcement for the transmission and distribution networks. Abdin et al. [86] assess the flexibility in electricity sector planning with a significant RES integration share. Zhang et al. [87] propose an integrated planning model to decide the optimal capacity and generation mix for the future electricity sector with the controllable EV and HP.

The previous works only consider conventional fossil fuel and low-carbon generation, and RES. However, achieving the net-zero target will require more other low-carbon, even zero-carbon and negative emissions electricity generation. To the best of the author’s knowledge, the impacts of hydrogen-fuelled generation and bioenergy generation on long-term electricity sector planning have yet to be investigated.

Heat sector decarbonisation: For the heat sector decarbonisation, the deployment of HP or HB has been stagnant. Therefore, different heat decarbonisation strategies switching away from fossil-fuel based heating to low-carbon heat need to be assessed from the perspective of system level. Zhang et al. [19] evaluate the economic performance of HP, DHN and hybrid heating technologies in the heating decarbonisation covering a one-year time horizon. Reference [88] applies the capacity expansion planning model to demonstrate the economic advantage of the HP-B over the simple boiler and HP system. The large-scale deployment of HP will expand the electricity system, including the generation, transmission, and distribution networks. The proposed model in [43] quantifies the benefits of HP integration for the carbon emissions and the integration cost of RES in the future GB's electricity sector. The continuing challenge of reducing carbon emissions drives the heat sector to develop a long-term, cost-effective decarbonisation pathway. The role of hydrogen in decarbonising the heat sector in GB from 2015 to 2050 is demonstrated in [89]. The authors in [90] apply a spatially-resolved optimisation model to determine the cost-effective pathway to decarbonise the energy sector, including electricity, heating, cooling and transport demand. The UK 2050 energy scenarios [91] set out a series of low-carbon pathways in conjunction with heating and transport electrification. The authors in [92] analyse the supply reliability based on six UK 2050 scenarios and investigated the influence of electric heating on the electricity sector.

The works mentioned above either focus on short-term investment decisions or lack the diversity of energy sources used in the same picture. Designing the heat sector's transition pathway needs to consider the evolution of different heat technologies and their combinations.

Transport sector decarbonisation: As two zero-emission vehicle technologies, EV and HFCV are vital components to achieve the net-zero target. However, the energy system implications of adopting EV and HFCV are still in debate. The transport sector needs to be decarbonised along with other related sectors like electricity and hydrogen sectors. The impact of EV demand on the electricity distribution network is investigated in [54]. Teng et al. [43] assess the benefits of flexibility from EV in the GB electricity sector in 2030 and 2050, based on a predefined EV penetration rate. They find that EV integration can significantly improve carbon reduction and renewable energy integration. As for the HFCV, using hydrogen as a sustainable fuel for the future transport sector is presented in [93]. The reference [73] proposes two strategies, HFCV and natural gas vehicle, to decarbonise the transport sector, evaluating their impact on the integrated electricity and transport sectors.

The above works concentrate on the impact of integrating the various types of vehicles on the overall system, the lack of impact of the evolution of the different types of vehicles on the long-term planning of the energy system and what factors influence the penetration of the different types of vehicles. Designing transition pathways for the transport sector requires optimisation at the system level in conjunction with other energy sectors.

Hydrogen and NETs appear to be a compelling pathway to decarbonisation that could be scaled up to various emitting sectors such as electricity, heat, and transport. Currently, the UK produces around 27 TWh of hydrogen annual [8]. UK gas emissions can be recalibrated to net emissions in 2025 if deployed capacity can deliver 110 TWh of hydrogen [94]. The existing studies about the hydrogen supply chain either focus on the optimisation of individual hydrogen infrastructures or only consider a one-year time horizon. However, hydrogen demand can be volatile, especially from a long-term perspective. How to characterise the uncertainty in hydrogen demand is a major concern worth studying. As a new and high-tech NET, DAC has received significant attention to providing a way to reduce carbon emissions. DAC offers inherent placement flexibility, reducing the need for pipelines from the capture site to the sequestration reservoir. The biomass utilisation supply chain and the DAC deployment are also two core elements of the transition pathway.

The works mentioned above either lack insights into the interactions between different energy sectors or only consider short-term decisions. The proposed framework in the present chapter considers the long-term energy infrastructures expansion planning and system operation accounting for key short-term technical constraints in the electricity, heat, transport sectors and hydrogen and NETs integration, aiming to minimise the accumulated whole system cost over the planning horizon. Meanwhile, each period's carbon target is guaranteed to be met.

The outline of the remainder of this chapter is organised as follows: Section 7.2 introduces the modelling approach of the proposed multi-year MES model. Section 7.3 explicitly presents the components of the objective function for the proposed model. Section 7.4 describes the main operating constraints for each modelling part.

7.2. Modelling Approach

The multi-year MES transition model can be extended based on the single-year model framework proposed in Chapter 3. Due to the flexibility of the single-year model, various new technologies can be integrated into the model. The time horizon can also be extended to long-term planning.

The proposed multi-year MES investment model can consider long-term time horizons planning prior to delivery from various energy production, transmission, distribution and storage. It also considers multiple system levels from long-distance energy transmission to distribution networks at a range of voltages. The model is optimised under detailed short-term and close-to-reality constraints to find the lowest costs for various energy sector infrastructure designs and investment profiles to achieve specific carbon targets across the energy system.

The overall optimisation framework proposed in this study is illustrated in Figure 7.1. Based on the adoption of given system information, the optimal design of the MES can be implemented, including the technology selection, sizing, and system operation.

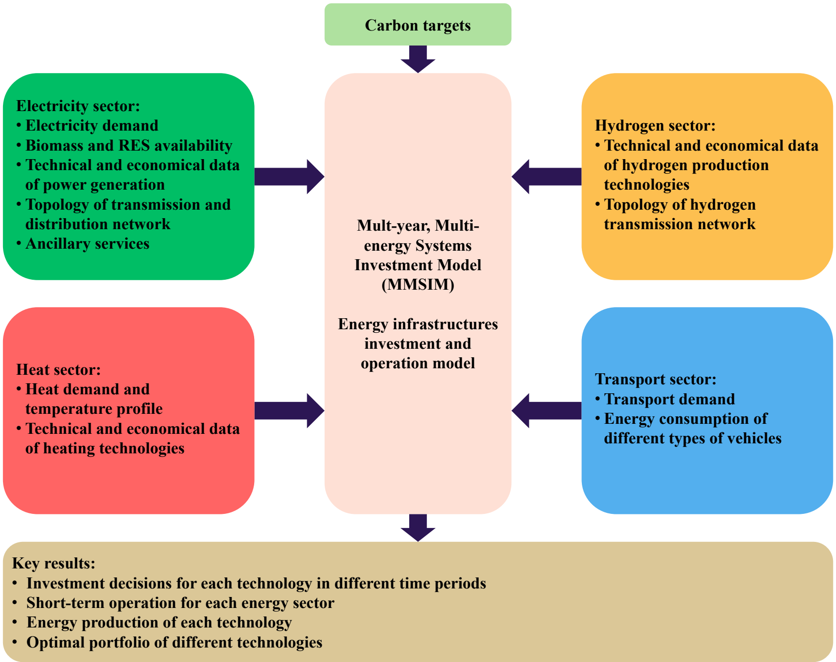

Figure 7.1. Overview of proposed multi-year, MES investment model.

7.3. Objective Function

The model is formulated as a MILP problem to minimise all the energy sectors' accumulated total cost from 2020 to 2054. The accumulated total cost consists of capital costs (including the O&M cost) for the infrastructures expansion in each energy sector and the operation and maintenance cost during each period. The accumulated capital cost relates to the lifetime of the corresponding technology. If the expected end of the lifetime of technology is within the time horizon of this study, the accumulated capital cost only accumulated till the end of its lifetime. Otherwise, if the expected end of life of technology exceeds the period of this study, the accumulated capital cost only calculated at the end of the time horizon. In the formulation, all accumulated capital cost is expressed as accumulated to the end of its lifetime to avoid confusion.

All the capital costs are discounted equally to each year over its entire lifetime or the whole planning and operation horizon in this study. The accumulated operation cost accumulated in each five years slot. Equations (7.1)-(7.3) express the electricity system's capital costs, representing the generation investment cost, network reinforcement cost, and electricity storage cost, respectively. The operating cost in the electricity sector is formulated as (7.4). Thus, the total cost in the electricity sector can be expressed in (7.5).

$$CAPEX_g = \sum_{y=2020}^{y+lt_g} \frac{c_{y,g} \cdot n_{y,g} \cdot \bar{P}_g}{(1+\beta)^{y-2020}} \tag{7.1}$$

$$CAPEX_{en} = \sum_{y=2020}^{y+lt_l} \sum_{l=1}^{L} \frac{c_{y,e_l} \cdot n_{y,e_l}}{(1+\beta)^{y-2020}} + \sum_{y=2020}^{y+lt_{dn}} \sum_{r=1}^{R} \frac{c_{y,hv_r} \cdot n_{y,hv_r} + c_{y,lv_r} \cdot n_{y,lv_r}}{(1+\beta)^{y-2020}} \tag{7.2}$$

$$CAPEX_{es} = \sum_{y=2020}^{y+lt_{bes}} \sum_{i=1}^{I} \frac{c_{y,bes_i} \cdot n_{y,bes_i}}{(1+\beta)^{y-2020}} + \sum_{y=2020}^{y+lt_{des}} \sum_{r=1}^{R} \frac{c_{y,hves_r} \cdot n_{y,hves_r} + c_{y,lves_r} \cdot n_{y,lves_i}}{(1+\beta)^{y-2020}} \tag{7.3}$$

$$OPEX_e = \sum_{y=2020}^{y+4} \sum_{t=1}^{T} \sum_{g=1}^{G} \frac{P_{y,t,g} \cdot o_{y,g} + \mu_{y,t,g} \cdot nl_{y,g} + st_{y,t,g} \cdot su_{y,g}}{(1+\beta)^{y-2020}} \tag{7.4}$$

$$TC_e = CAPEX_g + CAPEX_{en} + CAPEX_{es} + OPEX_e \tag{7.5}$$

For the heat sector, the capital cost of district heating consists of the capital cost of industrial heating technologies and DHN (7.6). Equation (7.7) formulates the investment costs of end-use heating appliances. The CTES and DTES are also considered to deploy on the DHN and end-use, respectively, and their capital cost is formulated in (7.8). The operating cost of NGB is formulated in (7.9). Thus, the total cost in the heat sector is presented in (7.10).

$$CAPEX_{hn} = \sum_{y=2020}^{y+lt_{hn}} \sum_{r=1}^{R} \frac{c_{y,ihp_r} \cdot n_{y,ihp_r} + c_{y,ingb_r} \cdot n_{y,ingb_r} + c_{y,hb_r} \cdot n_{y,hb_r}}{(1+\beta)^{y-2020}}$$
$$+ \sum_{y=2020}^{y+lt_{dhn}} \sum_{t=1}^{T} \sum_{r=1}^{R} c_{y,hn_r} \cdot (DH_{y,t} \cdot \lambda_{y,hn_r} - DH_{y-1,t} \cdot \lambda_{y-1,hn_r}) \tag{7.6}$$

$$CAPEX_{ed} = \sum_{y=2020}^{y+lt_{ed}} \sum_{r=1}^{R} \frac{\left\{ \begin{array}{c} c_{ehp_r} \cdot n_{ehp_r} + c_{engb_r} \cdot \left(\overline{nh}_{engb_r} + \overline{nh}_{engb_r}^{hy} \right) \\ + c_{ehb_r} \cdot \left(\overline{nh}_{ehb_r} + \overline{nh}_{ehb_r}^{hy} \right) \end{array} \right\}}{(1+\beta)^{y-2020}} \tag{7.7}$$

$$CAPEX_{tes} = \sum_{y=2020}^{y+lt_{ctes}} \sum_{r=1}^{R} \frac{c_{y,ctes_r} \cdot n_{y,ctes_r}}{(1+\beta)^{y-2020}} + \sum_{y=2020}^{y+lt_{etes}} \sum_{r=1}^{R} \frac{c_{y,etes_r} \cdot n_{y,etes_r}}{(1+\beta)^{y-2020}} \tag{7.8}$$

$$OPEX_h = \sum_{y=2020}^{y+4} \sum_{t=1}^{T} \sum_{r=1}^{R} \frac{o_{y,ngb_r} \cdot \frac{H_{y,t,ngb_r}}{\eta_{ngb}} + o_{y,engb_r} \cdot \frac{H_{y,t,engb_r}}{\eta_{engb}}}{(1+\beta)^{y-2020}} \tag{7.9}$$

$$TC_h = CAPEX_{hn} + CAPEX_{ed} + CAPEX_{tes} + OPEX_h \tag{7.10}$$

The capital cost of different types of vehicles (7.11) and their corresponding fuel cost are considered in the transport sector (7.12). The total cost in the transport sector is expressed as (7.13).

$$CAPEX_v = \sum_{y=2020}^{y+lt_v} \sum_{r=1}^{R} \frac{c_{y,fv_r} \cdot \overline{nc}_{fv_r} + c_{y,ev_r} \cdot \overline{nc}_{ev_r} + c_{y,hfcv_r} \cdot \overline{nc}_{hfcv_r}}{(1+\beta)^{y-2020}} \tag{7.11}$$

$$OPEX_v = \sum_{y=2020}^{y+4} \sum_{t=1}^{T} \sum_{r=1}^{R} \frac{o_{y,fv_r} \cdot V_{y,t,fv_r}}{(1+\beta)^{y-2020}} \tag{7.12}$$

$$TC_v = CAPEX_v + OPEX_v \tag{7.13}$$

The investment cost in the hydrogen integration consists of hydrogen production investment cost, hydrogen transmission pipeline investment cost and H2S investment cost (7.14). The operating cost in the hydrogen sector is formulated in (7.15). Thus, the overall hydrogen integration cost is presented as (7.16).

$$CAPEX_{h2} = \sum_{y=2020}^{y+lt_{h2}} \sum_{i=1}^{I} \frac{c_{y,el_i} \cdot n_{y,el_i} + c_{y,ghr_i} \cdot n_{y,ghr_i} + c_{y,bh_i} \cdot n_{y,bh_i}}{(1+\beta)^{y-2020}}$$
$$+ \sum_{y=2020}^{y+lt_{ht}} \sum_{l=1}^{L} \frac{c_{y,n_{ht_l}} \cdot n_{y,n_{ht_l}}}{(1+\beta)^{y-2020}} + \sum_{y=2020}^{y+lt_{hs}} \sum_{i=1}^{I} \frac{c_{y,hs_i} \cdot n_{y,hs_i}}{(1+\beta)^{y-2020}} \tag{7.14}$$

$$OPEX_{h2} = \sum_{y=2020}^{y+4} \sum_{t=1}^{T} \sum_{i=1}^{I} \frac{o_{y,ghr_i} \cdot \frac{Q_{y,t,ghr_i}}{\eta_{ghr}}}{(1+\beta)^{y-2020}} \tag{7.15}$$

$$TC_{h2} = CAPEX_{h2} + OPEX_{h2} \tag{7.16}$$

For the NETs integration, the total biomass supply chain costs, including the capital cost, operating costs, raw material costs, and total transport costs, are embedded into the electricity sector cost described in detail above. The capital cost of DAC is formulated in (7.17). A fully electrified DAC is adopted in this thesis; the operating cost of DAC can be expressed as a fixed percentage of its corresponding capital cost, which is included in DAC's capital cost for simplicity. The electricity consumption cost of DAC is accounted into the electricity sector. Thus, the total cost of NETs integration TC_{net} equals to $CAPEX_{dac}$ (7.18).

$$CAPEX_{dac} = \sum_{y=2020}^{y+lt_{dac}} \sum_{i=1}^{I} \frac{c_{y,dac_i} \cdot n_{y,dac_i} \cdot \overline{dac_i}}{(1+\beta)^{y-2020}} \tag{7.17}$$

$$TC_{net} = CAPEX_{dac} \tag{7.18}$$

Finally, the objective function of the model can be formulated in (7.19).

$$Min\ \varphi = TC_e + TC_h + TC_{h2} + TC_v + TC_{net} \tag{7.19}$$

7.4. Constraints

The constraints of the optimisation problem in the present chapter can be divided into six categories: electricity sector constraints, heat sector constraints, transport sector constraints, hydrogen integration constraints and NETs integration constraints, carbon emissions constraints. All constraints are applied to each time interval within the optimisation time horizon ($\forall y \in Y,\ \forall t \in T$) for all locations and regions ($\forall i \in I$, $\forall r \in R$), as well as all technologies ($\forall g \in G$). All constraints are described in detail in the following subsections.

7.4.1. Electricity Sector Constraints

Electricity balance constraints: The electricity balancing constraints are formulated as (7.20). The electricity demand consists of non-heat-based demand, the demand of HPs in the heat sector, and the electricity consumption of EL in the hydrogen sector and EV in the transport sector. It is worth noting that the operation of GHR-ATR and DAC both need to consume electricity.

$$\sum_{g=1}^{G} P_{y,t,g} + \sum_{i=1}^{I}\left(S^{+}_{y,t,es_i} - S^{-}_{y,t,es_i}\right) = \sum_{i=1}^{I}\left(\frac{Q_{y,t,el_i}}{\eta_{el}} + \frac{Q_{y,t,ghr_i}}{\eta^{e}_{ghr}} + \frac{dac_{y,t,i}}{\eta^{e}_{dac}}\right) + \sum_{r=1}^{R}\left(DE_{y,t,r} + \frac{H_{y,t,hp_r}}{\eta_{hp}} + \frac{H_{y,t,ehp_r}}{\eta_{y,t,ehp_r}} + V_{y,t,ev_r}\right) \tag{7.20}$$

Operation constraints in the electricity sector: The long-term planning model presented in this chapter also takes into account all the short-term operational constraints of the single-year model presented in Chapter 3, including the minimum stable generation and the maximum output of thermal generation (7.21)-(7.22), ramp up/down (7.23)-(7.24), start-up, synchronization, desynchronization (7.25)-(7.26), as well as minimum up and down time (7.27)-(7.28) constraints and annual energy production limits of thermal generation (7.29).

$$\mu_{y,t,g} \cdot \underline{P}_g \leq P_{y,t,g} \leq \mu_{y,t,g} \cdot \overline{P}_g \tag{7.21}$$

$$\mu_{y,t,g} \leq \overline{n}_{y,g} \tag{7.22}$$

$$P_{y,t,g} - P_{y,t-1,g} \leq \mu_{y,t,g} \cdot R^{u}_{g} \tag{7.23}$$

$$P_{y,t-1,g} - P_{y,t,g} \leq \mu_{y,t,g} \cdot R^{d}_{g} \tag{7.24}$$

$$st_{y,t,g} \geq \mu_{y,t,g} - \mu_{y,t-1,g} \tag{7.25}$$

$$dst_{y,t,g} \geq \mu_{y,t-1,g} - \mu_{y,t,g} \tag{7.26}$$

$$\sum_{k=t-\underline{up}_g}^{t-1} st_{y,t,g}^{k} \leq \mu_{y,t,g} \tag{7.27}$$

$$\mu_{y,t,g} \leq \bar{n}_{y,g} - \sum_{k=t-\underline{down}_g}^{t-1} dst_{y,t,g}^{k} \tag{7.28}$$

$$\sum_{t=1}^{T} P_{y,t,g} \leq af_g \cdot T \cdot \bar{n}_{y,g} \tag{7.29}$$

All the thermal power units that burn fossil fuel, nuclear energy or geothermal will inevitably produce waste heat. The CHP generation adopts this part of the heat for heating instead of being rejected to the environment. The operation model of CHP is described by (7.30)-(7.31) [48]. The loss of electricity is typically defined by the Z_{chp} factor which represents the useful heat gained in kWh for electricity lost in kWh. It can vary from about 4-10 in the power stations, which can be theoretically much higher depending on the Cv-factor ($1/Z_{chp}$) [95].

$$\mu_{y,t,g_{chp}} \cdot \underline{P}_{g_{chp}} \leq P_{y,t,g_{chp}} + \frac{H_{y,t,g_{chp}}}{Z_{chp}} \leq \mu_{y,t,g_{chp}} \cdot \overline{P}_{g_{chp}} \tag{7.30}$$

$$H_{y,t,g_{chp}} \leq \gamma_{chp} \cdot P_{y,t,g_{chp}} \tag{7.31}$$

Installed capacity constraints: The single-year model's key point is to provide comparisons among different types of decarbonisation strategies, which can be potentially applied in different counties for different periods. Therefore, assuming there is no existing capacity for all the technologies to provide a straightforward comparison among different scenarios.

The multi-year model takes into account the consistency of the long-term planning horizon and the links between different periods. The system is constrained by the previous periods' requirements. The existing capacity of different technologies and their relation between total installed capacity and newly-built capacity should be considered to make the model closer to reality. Therefore, the installed capacity of generation units could be expressed as the sum of existing capacity and newly-built capacity during the past periods minus the decommissioned capacity set to retire at the end of their lifetime, as shown in equation (7.32). For each type of electricity generation units, the annual newly-built capacity should not exceed an upper bound due to the limit of construction ability (7.33). The installed capacity of other infrastructure in the electricity sector, such as transmission and distribution networks, storage, etc., can be expressed in the same way and is omitted here for simplicity.

$$\overline{n}_{y,g} = \sum_{y=2020}^{y} n_{y,g} - n_{y,g}^{de} \tag{7.32}$$

$$n_{y,g} \leq nb_{y,g} \tag{7.33}$$

Electricity transmission and distribution constraints: Similar to the single-year model, the electricity transmission and distribution among the regions is limited by the capacity of lines, which is also the decision variables to be optimised in this model. The transmission capacity is limited by (7.34). They are applied to all transmission lines ($\forall l \in L$). Due to the presence of CHP generation, assuming the CHP is deployed in the high-voltage distribution network. The power flow and reverse power flow on the distribution network can be expressed as (7.35)-(7.38).

$$-\overline{n}_{y,e_l} \leq f_{t,e_l} \leq \overline{n}_{y,e_l} \tag{7.34}$$

$$\begin{aligned} &\xi \cdot DE_{y,t,r} + \frac{H_{y,t,hp_r}}{\eta_{hp}} + \frac{H_{y,t,ehp_r}}{\eta_{y,t,ehp_r}} + V_{y,t,ev_r} + S_{y,t,es_i}^{hv-} + S_{y,t,es_i}^{lv-} \\ &-S_{y,t,es_i}^{hv+} - S_{y,t,es_i}^{lv+} - P_{y,t,g_{chp}} - P_{y,t,pv_r}^{hv} - P_{y,t,pv_r}^{lv} \leq \overline{n}_{y,hv_r} \end{aligned} \tag{7.35}$$

$$(1-\xi) \cdot DE_{y,t,r} + \frac{H_{y,t,ehp_r}}{\eta_{y,t,ehp_r}} + V_{y,t,ev_r} + S_{y,t,es_i}^{lv-} - S_{y,t,es_i}^{lv+} - P_{y,t,pv_r}^{lv} \leq \overline{n}_{y,lv_r} \tag{7.36}$$

$$\begin{aligned} &P_{y,t,g_{chp}} + P_{y,t,pv_r}^{hv} + P_{y,t,pv_r}^{lv} + S_{y,t,es_i}^{hv+} + S_{y,t,es_i}^{lv+} - S_{y,t,es_i}^{hv-} - S_{y,t,es_i}^{lv-} \\ &- \xi \cdot DE_{y,t,r} - \frac{H_{y,t,hp_r}}{\eta_{hp}} - \frac{H_{y,t,ehp_r}}{\eta_{y,t,ehp_r}} - V_{y,t,ev_r} \leq \sigma_{hv} \cdot \overline{n}_{y,hv_r} \end{aligned} \tag{7.37}$$

$$P^{lv}_{y,t,pv_r} + S^{lv+}_{y,t,es_i} - S^{lv-}_{y,t,es_i} - (1-\xi)\cdot DE_{y,t,r} - \frac{H_{y,t,ehp_r}}{\eta_{y,t,ehp_r}} - V_{y,t,ev_r} \le \sigma_{lv}\cdot \overline{n}_{y,lv_r} \tag{7.38}$$

Ancillary services constraints: Frequency response (7.39) and operating reserve (7.40) are two balancing services considered in this model. Besides the thermal generation to provide ancillary services (7.41)-(7.43), the supplementary frequency response and operating reserve can also be provided by the electricity storage, heating sector (HP) and hydrogen sector (EL), as well as the transport sector (EV). The frequency response and operating reserve provided by the heating appliances, EL and EV, are also limited by their maximum output, which is similar to the single-year model but applies for all the time horizon in the multi-year model. They are all omitted here for simplicity.

$$\sum_{g=1}^{G} rsp_{y,t,g} + \sum_{i=1}^{I}\left(\alpha_{es_i}\cdot S^{-}_{y,t,es_i}\right) + \sum_{r=1}^{R}\left(rsp_{y,t,hp_r} + rsp_{y,t,ehp_r} + rsp_{y,t,ev_r} + rsp_{y,t,el_r}\right) \ge \overline{SF}_{y,t} \tag{7.39}$$

$$\sum_{g=1}^{G} res_{y,t,g} + \sum_{i=1}^{I}\left(\overline{n}_{y,es_i} - S^{-}_{y,t,es_i} + S^{+}_{y,t,es_i}\right) + \sum_{r=1}^{R}\left(res_{y,t,hp_r} + res_{y,t,ehp_r} + res_{y,t,ev_r} + res_{y,t,el_r}\right) \ge \overline{SR}_{y,t} \tag{7.40}$$

$$rsp_{y,t,g} \le \mu_{y,t,g}\cdot \overline{rsp}_g \tag{7.41}$$

$$res_{y,t,g} \le \mu_{y,t,g}\cdot \overline{res}_g \tag{7.42}$$

$$\mu_{y,t,g}\cdot \underline{P}_g \le P_{y,t,g} + rsp_{y,t,g} + res_{y,t,g} \le \mu_{y,t,g}\cdot \overline{P}_g \tag{7.43}$$

Storage constraints: In this model, various energy storages are considered, including BES on the transmission level, DES on the distribution level, CTES on the DHN, DTES for the end-use heating appliances and the H2S. All types of storage are modelled in the same manner, including the maximum storage charging/discharging rate (7.44)-(7.45), constraints associated with the content of storage (7.46), and the storage energy balance constraints (7.47) are presented.

$$S^{+}_{y,es_i,t} \leq \overline{n}_{y,es_i} \tag{7.44}$$

$$S^{-}_{y,es_i,t} \leq \overline{n}_{y,es_i} \tag{7.45}$$

$$SC_{y,es_i,t} \leq \overline{n}_{y,es_i} \cdot est_{es_i} \tag{7.46}$$

$$SC_{y,es_i,t} = SC_{y,es_i,t-1} - S^{-}_{y,bes_i,t} + \eta_{es} \cdot S^{+}_{y,es_i,t} \tag{7.47}$$

7.4.2. Heat Sector Constraints

In the heat sector of the present model, the heat demand is also supplied by the district heating (7.48) and end-use appliances (7.49)-(7.53) (e.g., stand-alone NGB, HP and HB and hybrid HP-B, HP-HB). The heat balance constraints are formulated in (7.54).

$$\begin{aligned} &H_{y,t,chp_r} + H_{y,t,hp_r} + H_{y,t,ngb_r} + H_{y,t,hb_r} \\ &+S^{+}_{y,ctes_r,t} - S^{-}_{y,ctes_r,t} = DH_{y,t,r} \cdot \lambda_{y,hn_r} \end{aligned} \tag{7.48}$$

$$H_{y,t,egb_r} + S^{+}_{y,dtes_r,t} - S^{-}_{y,dtes_r,t} = DH_{y,t,r} \cdot \lambda_{y,egb_r} \tag{7.49}$$

$$H_{y,t,ehp_r} + S^{+}_{y,dtes_r,t} - S^{-}_{y,dtes_r,t} = DH_{y,t,r} \cdot \lambda_{y,ehp_r} \tag{7.50}$$

$$H_{y,t,ehb_r} + S^{+}_{y,dtes_r,t} - S^{-}_{y,dtes_r,t} = DH_{y,t,r} \cdot \lambda_{y,ehb_r} \tag{7.51}$$

$$H^{hy,engb}_{y,t,ehp_r} + H^{hy,engb}_{y,t,egb_r} + S^{+}_{y,dtes_r,t} - S^{-}_{y,dtes_r,t} = DH_{y,t,r} \cdot \lambda^{hy}_{y,engb_r} \tag{7.52}$$

$$H^{hy,ehb}_{y,t,ehp_r} + H^{hy,ehb}_{y,t,ehb_r} + S^{+}_{y,dtes_r,t} - S^{-}_{y,dtes_r,t} = DH_{y,t,r} \cdot \lambda^{hy}_{y,ehb_r} \tag{7.53}$$

$$\lambda_{y,hn_r} + \lambda_{y,egb_r} + \lambda_{y,ehp_r} + \lambda_{y,ehb_r} + \lambda^{hy}_{y,engb_r} + \lambda^{hy}_{y,ehb_r} = 1 \tag{7.54}$$

This model assumes that each household will change the heating appliance at the end of the heating technologies' lifetime. Therefore, the number of households with different heating appliances could be expressed as the sum of newly-installed households with corresponding heating appliances during the past periods minus households with decommissioned heating appliances. Equation (7.55) represent the households that connect to the DHN. The number of households with other heating technologies can be expressed in the same manner.

$$\overline{nh}_{y,hn_r} = \sum_{y=2020}^{y} nh_{y,hn_r} - nh_{y,hn_r}^{de} \tag{7.55}$$

7.4.3. Transport Sector Constraints

In order to develop a cost-effective transition pathway to decarbonise the transport sector at the system level, conventional FVs (such as the petrol vehicles in this study) are considered for the transport sector. EVs and HFCVs are two options for phasing out FVs. The transport demand balancing can be described by (7.56)-(7.59). The equation (7.60)-(7.61) describe the potential DSR for the flexible EV's demand. As shifting demand may increase the overall energy requirements, the DSR efficiency (e.g., η_{dsr}) is considered to represent the losses driven by the temporal shifting of demand.

$$V_{y,t,fv_r} = \lambda_{y,fv_r} \cdot DT_{y,t,r} \tag{7.56}$$

$$V_{y,ev_r,t} \cdot \frac{\eta_{y,fv}}{\eta_{y,ev}} = \lambda_{y,ev_r} \cdot DT_{y,t,r} + dsr_{y,t,r}^{+} - dsr_{y,t,r}^{-} \tag{7.57}$$

$$V_{y,hfcv_r,t} \cdot \frac{\eta_{y,fv}}{\eta_{y,hfcv}} = \lambda_{y,hfcv_r} \cdot DT_{y,t,r} \tag{7.58}$$

$$\lambda_{y,fv_r} + \lambda_{y,ev_r} + \lambda_{y,hfcv_r} = 1 \tag{7.59}$$

$$dsr_{y,t,r}^{-} \leq \varepsilon_y \cdot DT_{y,t,r} \tag{7.60}$$

$$\sum_{t \in D} dsr_{y,t,r}^{-} \leq \eta_{dsr} \cdot \sum_{t \in D} dsr_{y,t,r}^{+} \tag{7.61}$$

Similar to the heating appliances, this model assumes all vehicles will retire at the end of their lifetime. Therefore, the number of different types of vehicles could be expressed as the sum of newly-bought vehicles during the past periods minus the retired vehicles (7.62)-(7.64).

$$\overline{nc}_{y,fv_r} = \sum_{y=2020}^{y} nc_{y,fv_r} - nc_{y,fv_r}^{de} \tag{7.62}$$

$$\overline{nc}_{y,ev_r} = \sum_{y=2020}^{y} nc_{y,ev_r} - nc_{y,ev_r}^{de} \tag{7.63}$$

$$\overline{nc}_{y,hfcv_r} = \sum_{y=2020}^{y} nc_{y,hfcv_r} - nc_{y,hfcv_r}^{de} \tag{7.64}$$

7.4.4. Hydrogen Integration Constraints

The hydrogen integration system in the multi-year model is the same as the single-year hydrogen integration system, including hydrogen production, transmission and storage. In the single-year model, the natural gas-based hydrogen production technologies are mainly SMR and GHR technologies. GHR is not a self-sufficient forming technology, and the external heat source is required to meet the reforming needs. Typically, the GHR unit can combine with a high-temperature heat source from the ATR. In the ATR technology, part of the natural gas feed is partially combusted to generate heat for the endothermic reforming reaction. This self-heating mechanism largely eliminates the need for any external heating. Stand-alone ATR technology is considered uneconomical, but it is more attractive for a high capture rate of carbon emission (e.g., >90%). This study considers GHR-ATR as a blue hydrogen production technology. Meanwhile, due to the biomass supply chain's presence in this model, BHCCS is also a method to produce hydrogen. Therefore, the hydrogen demand balancing can be expressed in (7.65).

$$\sum_{i=1}^{I}\left(Q_{y,t,el_i} + Q_{y,t,ghr_i} + Q_{y,t,bh_i} + S_{y,t,hs_i}^{+} - S_{y,t,hs_i}^{-}\right) = \sum_{g\in I_i} \frac{P_{y,t,h2_g}}{\eta_{h2_g}} + \sum_{r=1}^{R}\left(\frac{H_{y,t,hb_r}}{\eta_{hb}} + \frac{H_{y,t,ehb_r}}{\eta_{ehb}} + V_{y,t,hfcv_r}\right) \tag{7.65}$$

Hydrogen transport and storage are modelled in the same way as the single-year model and are omitted here for brevity.

7.4.5. Negative Emissions Technologies Integration Constraints

In this subsection, the modelling frameworks of the biomass supply chain and DAC technology are presented. For bioenergy deployments using CCS, the biomass supply chain model is integrated into the overall MES modelling framework to determine optimal land use planning at the system level, taking into account the biomass supply network's evolution.

The complete biomass supply chain is described as a spatial-temporal specific, multi-year optimisation model. The raw biomass material is collected from the farms or waste collection sites, then transported to the pellet production plants to convert raw biomass material into pellets burned by the biomass combustion plants. The pellets are then transported to the energy production plants to generate electricity, heat or other energy forms like hydrogen, where the generated carbon dioxide is captured through CCS.

Biomass raw material distribution: In this model, only considering the biomass supply chain in GB. Six types of raw biomass material are considered: miscanthus, poplar, MSW, waste wood, forest residue and crop residue. The data about dry matter yields of miscanthus and poplar are referred to in [96]. The yields of forest residue and crop residue data are collected in [97] and [98]. The availability of MSW and waste wood can be treated as a function of population density sourced from [37].

Zhang et al. [37] adopt the above data and convert them into the geophysical data set for the GB system, which is discretised into 140 regions, 50 by 50 km each. The 140 regions of British National Grid coordination can be aggregated into ten regions: 1). Scotland, 2). North, 3). North-West (NW), 4). North-East (NE), 5). Wales, 6). East Midlands (E Midlands), 7). West Midlands (W Midlands), 8). East Anglia (E Anglia), 9). South-West (SW), 10). South-East (SE).

This study further aggregates geophysical datasets of biomass resource availability for ten regions based on geographical features to fit the simplified GB transmission system for the five regions presented in Chapter 6. Assuming that Scotland corresponds to the SCOT, the North, NW and NE regions fall into the EW-N region. Wales, W Midlands and E midlands are grouped into the EW-M region. E Anglia is considered to be a LON region. The SW and SE fall within the EW-S region. The correspondence between the two systems is illustrated in Figure 7.2.

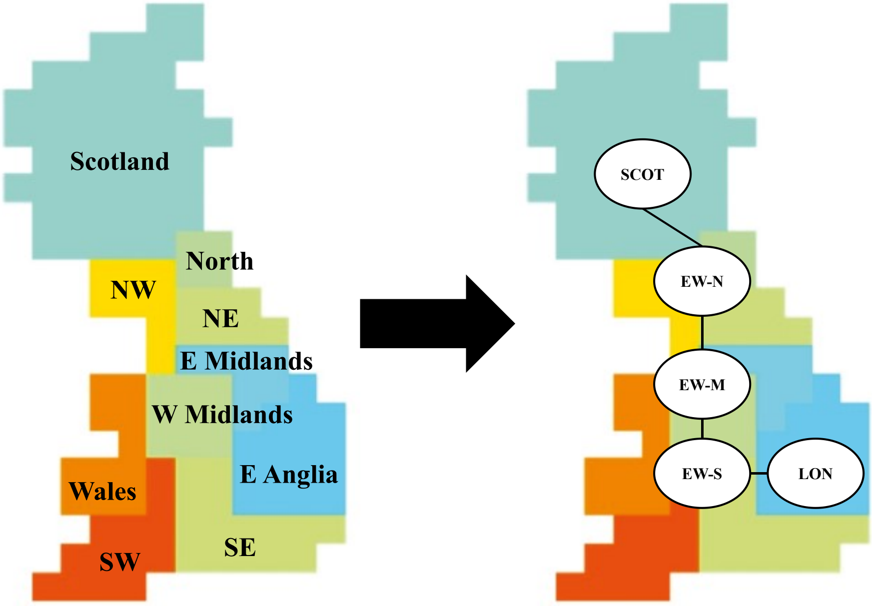

Figure 7.2. Correspondence between two geographical systems of GB.

Biomass raw material availability: The biomass raw material availability is determined by the dry matter of yields and the land availability for virgin biomass farms. The detailed British National Grid coordination, miscanthus and poplar yields, waste wood, MSW, crop residue and waste residue availabilities and biomass land availability from 2020 to 2050 can be calculated adopting the new biomass raw material distribution mentioned in the above subsection.

The total annual virgin biomass crop yield of raw material (TB) can be calculated by the maximum virgin biomass crop yield of raw material (BA) times the maximum biomass land availability (LA) (7.66).

$$TB_{y,i,b} = BA_{y,i,b} \cdot LA_{y,i} \tag{7.66}$$

As mentioned before, all the biomass raw material must convert to biomass pellet for energy production. The biomass pellet cost considers the different costs incurred along the biomass supply chain. Pellet conversion rates are applied for the cost calculation, accounting for moisture removal and material loss during the pellet production process. Figure 7.3 presents the pellet cost calculation, which is also formulated as (7.67). The total cost of biomass pellet consumption is determined by the pellet cost (PT) and the demand for the biomass pellet (BP), which is accounted as the electricity operation cost considered into the operating cost of the electricity sector. The maximum availability of biomass pellet can be expressed as (7.68).

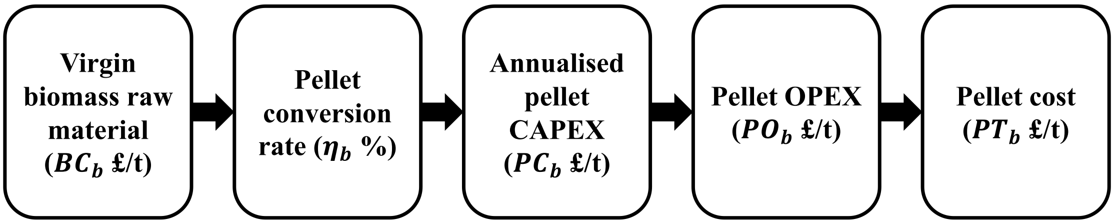

Figure 7.3. The calculation of pellet cost.

$$PT_{y,b} = \frac{BC_{y,b}}{\eta_b} + PC_{y,b} + PO_{y,b} \tag{7.67}$$

$$TP_{y,i,b} = TB_{y,i,b} \cdot \eta_b \tag{7.68}$$

Bioenergy balance constraints: The bioenergy is mainly used for supplying BECCS, BECHPCCS and BHCCS. The bioenergy consumption of BECCS, BECHPCCS and BHCCS are determined by the demand for the biomass pellet (BP) and their corresponding energy density (ρ), thus times the plant's efficiency. They can be expressed in (7.69)-(7.71), respectively.

$$P_{y,t,g_{be}} = \sum_{b=1}^{B} BP_{y,t,b,g_{be}} \cdot \rho_b \cdot \eta_{b,be} \tag{7.69}$$

$$P_{y,t,g_{bechp}} = \sum_{b=1}^{B} BP_{y,t,b,g_{bechp}} \cdot \rho_b \cdot \eta_{bechp} \tag{7.70}$$

$$Q_{y,t,bh_i} = \sum_{b=1}^{B} BP_{y,t,b,bh_i} \cdot \rho_b \cdot \eta_{bh} \quad (7.71)$$

The annual biomass pellet consumption should not exceed the annual maximum biomass pellet availability (7.72). For the biomass transmission between the regions, assuming biomass material can be transferred between regions by rail, modelled by the transportation model but without transmission limit.

$$\sum_{g=1}^{G}\sum_{t=1}^{T}\left(BP_{y,t,b,g_{be}} + BP_{y,t,b,g_{bechp}}\right) + \sum_{i=1}^{I}\sum_{t=1}^{T} BP_{y,t,b,bh_i} \le \sum_{i=1}^{I}\sum_{b=1}^{B} TP_{y,i,b} \quad (7.72)$$

Direct air capture operation constraints: For the operation of the DAC facility, the annual captured carbon dioxide should not exceed the total annual capacity of DAC facilities (7.73).

$$\sum_{t=1}^{T} dac_{y,t,i} \le \bar{n}_{y,dac_i} \cdot \overline{dac_i} \quad (7.73)$$

7.4.6. Carbon Emissions Constraints

The positive carbon emissions in the whole system of this study are from electricity, heat, transport and hydrogen sectors. Meanwhile, NETs can provide negative carbon emissions to offset the positive carbon emissions. The carbon target unit in this model is set at g/kWh to reflect the carbon intensity associated with the overall energy demand, given the long process of achieving the net-zero target by 2050. The carbon emissions from the electricity, heat, transport and hydrogen sectors can be expressed as (7.74)-(7.77), respectively.

$$CA_{y,e} = \sum_{t=1}^{T}\sum_{g=1}^{G} P_{y,g,t} \cdot ce_g \quad (7.74)$$

$$CA_{y,h} = \sum_{t=1}^{T}\sum_{r=1}^{R}\left(H_{y,ngb_r,t} \cdot ce_{ngb} + H_{y,engb_r,t} \cdot ce_{engb}\right) \quad (7.75)$$

$$CA_{y,v} = \sum_{t=1}^{T}\sum_{r=1}^{R} V_{y,fv_r,t} \cdot ce_{fv} \tag{7.76}$$

$$CA_{y,h2} = \sum_{t=1}^{T}\sum_{i=1}^{I} Q_{y,ghr_i,t} \cdot ce_{ghr} \tag{7.77}$$

The negative emissions provided by bioenergy consumption are mainly from the carbon stored in the biomass raw material. The total weight of carbon in the biomass pellet can be determined by the weight of biomass pellet (TP) and their corresponding carbon content (CC). The atomic weight of a carbon atom is 12, and the atomic weight of oxygen is 16, so the total atomic weight of carbon dioxide is 44. This means that a certain amount of carbon dioxide can be expressed in terms of the amount of carbon it contains, i.e., the amount of carbon multiplied by the ratio of the molecular weight of carbon in carbon dioxide (i.e., 44/12). Therefore, the negative emissions from biomass pellet consumption can be expressed in (7.78). The negative emissions achieved by DAC can be formulated as (7.79).

$$CA_{y,bio} = \frac{44}{12} \cdot \sum_{t=1}^{T}\sum_{i=1}^{I}\sum_{b=1}^{B} TP_{y,i,b} \cdot CCR \cdot CC_b \tag{7.78}$$

$$CA_{y,dac} = \sum_{t=1}^{T}\sum_{i=1}^{I} dac_{y,t,i} \tag{7.79}$$

Besides the carbon emissions mentioned above, the additional other carbon emissions ($CA_{y,other}$) which is challenging to decarbonise in the whole system is also consider into the carbon emission constraints. In order to avoid excessive pressure to reduce carbon emissions from a single energy sector (e.g., electricity, heat and transport sectors), allowing the total carbon emissions from each energy sector can increase by a small percentage compared to the previous period (7.80)-(7.82). The carbon emission constraint for the whole system can be expressed as (7.83).

$$CA_{y,e} \le (1+\omega) \cdot CA_{y-1,e} \tag{7.80}$$

$$CA_{y,h} \le (1+\omega) \cdot CA_{y-1,h} \tag{7.81}$$

$$CA_{y,v} \leq (1+\omega) \cdot CA_{y-1,v} \tag{7.82}$$

$$CA_{y,e} + CA_{y,h} + CA_{y,v} + CA_{y,h2} + CA_{y,other} - CA_{y,bio} - CA_{y,dac} \leq CT_y \cdot \sum_{t=1}^{T} \sum_{i=1}^{I} \left(DE_{y,t,i} + DH_{y,t,i} + DT_{y,t,i} \right) \tag{7.83}$$

Chapter 8. A Long-term Multi-Regional, Multi-Energy Systems Planning Towards the Future Low-Carbon Energy System of Great Britain

8.1. Introduction

As the mix of energy production and energy demand changes from now to 2050, all energy sectors will be making a variety of challenging investment decisions to achieve the UK's net-zero carbon target for 2050 and maintain a resilient, secure and affordable energy system.

The transition pathways for future energy system should be designed in the context of MES, which considers the uncertainties of fossil fuels price, technologies cost and the different regional dynamics and characteristics. Yet, despite these uncertainties, key investment decisions need to be made in the short term, which will have a lasting impact on the future energy system. It is necessary to implement comprehensive, analytical, and detailed long-term MES planning to provide a cost-effective roadmap towards a low-carbon energy future. There is also a need to demonstrate the role of various low-carbon technologies in the transition of each energy sector and their cross-sector impacts. The present chapter adopts the multi-year MES transition model proposed in Chapter 7 to address future energy supply pathways for GB where cost and carbon targets are the priorities.

The outline of the remainder of this chapter is organised as follows: Section 8.2 presents the system description and the scenario setting. In Section 8.3, a series of case studies are performed to analyse three transition pathways. In Section 8.4, the impact of flexibility on the transition pathway is investigated. In Section 8.5, the comparison among three pathways and policy recommendations are discussed. The conclusions are provided in Section 6.4.

8.2. System Description and Scenario Setting

The framework of the multi-year model is presented in Figure 2.1, which fully considers all the components. This study is also tested in a simplified GB transmission system proposed in Chapter 5.

The capital costs, O&M cost and expected lifetime and discount rate and other operational parameters of each technology in the whole system are listed in Appendix A. Learning effect leads to declining tread on various costs, which is also considered in this study. Assuming the GB is energy neutral at the annual level, representing the total annual demand is equal to annual production while allowing short-term electricity exchanges with the interconnected countries.

In this study, the potential GB biomass resource availability is listed in Appendix A, and the data are converted into the geographic structure adapted to this study. All the raw biomass materials need to be converted into pellets for energy production. Considering the cultivated area, types of crops, yields resulting from different climate conditions, soil conditions and farming practices, we assume the biomass materials utilisation rate varies between 30% and 60%.

The operational cost of electricity generation depends on the fuel price in different years. The fuel price refers to [99], which are listed in Table 8.1.

Table 8.1. Future natural gas price.

	2020	2025	2030	2035	2040	2045	2050
Gas price (p/therm)	48	56	63	63	63	63	63

The initial electricity and heat demand and the hourly resource availability of RES in 2020 refer to [100], and their future pathways refer to [101], [102] (Table 8.2). The number of households in the planning horizon is listed in Table 8.3, which refer to [103]. The transport demand is calculated based on the number of licensed cars and road traffic (vehicle miles) [104] (Table 8.4).

Table 8.2. Future electricity and heat demand (TWh).

	2020	2025	2030	2035	2040	2045	2050
Electricity demand	335	338	341	361	377	399	422
Heat demand	657	697	739	756	778	800	826

Table 8.3. The number of households in GB.

	2020	2025	2030	2035	2040	2045	2050
The number of households (millions)	27.8	28.7	29.7	30.7	31.8	32.9	34.0

Table 8.4. The number of licensed cars and Road traffic in GB.

	2020	2025	2030	2035	2040	2045	2050
The number of cars (millions)	32.3	34.4	36.5	38.6	40.7	42.8	44.9
Road traffic (billion km)	576.4	613.9	651.5	689.0	726.5	764.1	801.6

Annual system-wide carbon emissions do not exceed each five-year target, which is based on the Climate Change Committee's review of the Carbon budgets [101] and have been modified in this study in line with the UK government's current target of zero carbon emissions by 2050 (Table 8.5).

Table 8.5. GB carbon targets from 2020 to 2050 (g/kWh).

	2020	2025	2030	2035	2040	2045	2050

Carbon target	200	100	50	30	20	10	0

The energy supply and demand are balanced on a regional basis. Spatial and temporal characteristics of energy demand and RES in different regions are considered. The model is conducted on the national level, introducing a spatial module in which the regions are connected through the interconnectors.

In order to obtain accurate and robust optimisation results of system design and operation, the hourly energy balance is applied in the temporal module. Typical weeks and chronological order are adopted for the temporal module input data to reduce computational complexity using the clustering algorithm k-medoids. The MATLAB®-embedded clustering algorithm k-medoids [105] is applied to choose a set of design weeks according to the input demand data and renewable energy profile. Four design weeks are selected from 365 days of one year.

The k-means clustering technique is commonly used as one of the most popular unsupervised clustering algorithms to classify input data into K clusters through an iterative procedure [106]. Let $X = [x_1, \dots, x_n]^T \in \mathbb{R}^{m \times n}$ denote the set of n dimensional points to be clustered into a set of K clusters, finding the K centroids $C = [c_1, \dots, c_K]^T \in \mathbb{R}^{K \times n}$ of clusters $X^k \subset X, k = 1, \dots, K$. The k-means algorithm finds a partition such that the squared error between the empirical mean of a cluster and the points in the cluster is minimised. The squared error between X_i^k and the points in cluster c_k is defined as (8.1).

$$D(X_i^k) = \sum_{X_i^k \in c_k} \left\| X_i^k - c_k \right\|^2 \tag{8.1}$$

Mathematically, the objective function, within-cluster sum of squares, can be written as follows:

$$\min \left(\sum_{k=1}^{K} \sum_{X_i^k \in c_k} \left\| X_i^k - c_k \right\|^2 \right) \tag{8.2}$$

The main steps of the k-means algorithm can be described in the following steps [107]:

Step 1: Select an initial partition with K clusters; repeat steps 2 and 3 until cluster membership stabilises.

Step 2: Generate a new partition by assigning each pattern to its closest cluster centre.

Step 3: Computer new cluster centres.

Although k-means clustering is a fast, robust and easy implementing clustering technique, which starts with an initial partition with K clusters and assigns patterns to clusters to reduce the squared error, the quality of clustering highly depends on the initial centroids and the number of clusters, which is an unknown prior. Based on the k-means clustering and the medoid shift algorithm, the k-medoids clustering method aims to minimize the sum of dissimilarities between the data points assigned in a cluster and its corresponding central point [108].

In order to maintain the original structure of the data to reflect the real energy and RES profile variability, this thesis adopts the k-medoids method which the mean value in each cluster is replaced with the actual median to select the representative weeks and to ensure the effectiveness of the k-medoids algorithm, principal component analysis is necessary to use to convert a set of observations of possibly correlated variables (entities each of which takes on various numerical values) into a set of values of linearly uncorrelated variables called principal components.

This study considers three core pathways for decarbonising electricity, heat and transport sectors (Table 8.6).

Table 8.6. Description of three decarbonisation pathways.

Pathways	Description

Hydrogen pathway	The core hydrogen pathway is based on the application of hydrogen-fuelled generation, HB and HFCV at electricity, heat and transport sectors, respectively, to decarbonise the whole energy demand.
Electric pathway	In this pathway, hydrogen integration is not considered across the whole system. Heat and transport demand is decarbonised by the optimal deployment of electric heating devices (e.g., HP) and EV, respectively.
Hybrid pathway	This pathway is based on the deployment of combining the hydrogen and electric applications in the electricity, heat and transport sectors.

In order to make the study follow the reality of the UK energy system, the model considers the existing generation capacity in the UK [109], which is listed in Table 8.7. Assuming the hydrogen-fuelled generation will be available until 2030. The maximum newly-built capacity for the generation is 2 GW, and the RES generation newly-built capacity is 3 GW. The maximum existing capacity of nuclear generation is 9 GW. The maximum newly-built capacity for wind power will increase to 6 GW after 2030. As mentioned above, around 80% of heat demand is met by natural gas, and approximately 22 million homes in the UK currently have central gas heating. For the heat sector in this study, assuming 80% of total households install stand-alone NGB in 2020. For the transport sector in this study, EV's penetration level in the current market is only 10%. Assuming 90% of total vehicles are still FVs in 2020, assuming the sale of FVs will not be permitted from 2030 onwards. For the hydrogen infrastructure construction, considering the maximum newly-built capacity of the hydrogen infrastructure is 6 GW.

Table 8.7. Existing operational generation capacity in the UK.

	2020	2025	2030	2035	2040	2045	2050
Nuclear	8.9	8.9	8.9	7.0	7.0	3.6	1.2
CCGT	23.5	14.0	10.4	4.4	0.0	0.0	0.0
Wind	19.4	19.3	17.7	13.2	6.3	0.0	0.0

Farm PV	3.9	3.9	3.9	3.8	0.3	0.0	0.0
BECCS	3.2	3.2	3.2	3.0	0.1	0.0	0.0

8.3. Case Studies

This section presents a series of case studies to answer RQ4 for this thesis. In addition, this chapter discusses several specific research questions related to RQ4, which can be summarised as follows:

- Analyse the economic performance and drivers of different decarbonisation pathways for the integrated electricity, heat and transport sectors.
- Understand the implications of different transition pathways on the structure of the electricity, heat, transport sectors, and the hydrogen supply chain, as well as the carbon emissions from each sector.
- Identify the impact of cross-energy system flexibility on the decarbonisation pathways.

8.3.1. Analysis of Hydrogen Pathway

Total system cost over the time horizon under the hydrogen pathway is shown in Table 8.8. The table indicates a significant rise in annual undiscounted cost towards the 2025-2029 period, which subsequently level off. This is driven by the projected tightening of carbon targets from 200 g/kWh in 2020 to 100 g/kWh in 2030. Various low-carbon technologies such as RES, biomass-based applications and hydrogen infrastructure begin to enter the market to decarbonise various energy sectors. The hydrogen pathway’s cumulative discounted system cost is £1465.8 billion, comprising the cost of electricity sector expansion (£557.2 billion) and cost for the heat sector

(£421.9 billion). The total hydrogen infrastructure investment and operation cost are £481.0 billion. The DAC cost is only £5.7 billion.

Table 8.8. Total system cost to 2054 in hydrogen pathway.

Five-year period	2020-2024	2025-2029	2030-2034	2035-2039	2040-2044	2045-2049	2050-2054	2020-2054
System cost £bn (undiscounted)	245.0	342.2	369.6	388.4	405.8	420.4	447.6	2619.1
System cost £bn (discounted)	228.9	269.3	244.9	216.7	190.6	166.3	149.0	1465.8

The cumulative undiscounted system cost in five-year periods to 2054 for the hydrogen pathway is shown in Figure 8.1. There are 22 different cost categories which are grouped into capital expenditure (C), operating cost (O) and O&M cost (OM). Since investments in the transport sector (e.g., vehicles' capital cost) are much higher than in other sectors, they are not shown in this figure and other cost-related figures in the following cases. The following costs are associated with the costs of decarbonising the electricity sector. Only £15.4 billion in the high-carbon electricity generation capacity and its investment are declining as carbon targets are tightened. The investment in low-carbon and biomass-fuelled generation is £129.3 billion and £79.1 billion, respectively. The investment required in both types of generation increases until 2030, decreases due to the wind power becoming more cost-effective. A high level of RES additional costs incurred from 2030 to 2054 (£275.9 billion, 10.5% of the total cost), and the investment in RES generation keeps increasing from £24.3 billion in 2020-2024 to £54.1 billion in 2050-2054. This is partly due to the replacement of onshore wind power by offshore wind power from 2030 onwards. The electricity network upgrade needs £40.0 billion, mostly at the transmission level (£25.8 billion). The electricity sector's operating cost of fuel burnt become less from £30.2 billion in 2020-2024 to £18.8 billion in 2050-2054 as the electricity generation contains more zero-marginal-cost generation.

In the heat sector, the heating supply is dominated by the end-use NGB in 2020-2024. From 2030, the heat sector begins to decarbonise deeply; the penetration of DHN increases significantly. Its cost increases from £6.9 billion in 2020-2024 to £24.1 billion in 2025-2029. District heating investment remains steady after 2030 as the capital cost curves for the DHN and industrial heat technologies are relatively stable. In 2030, a large part of existing NGBs need to be replaced with low-carbon heating appliances, the investment in end-use heating appliances increases to £33.8 billion. From 2035 onwards, the capital cost of end-use heating appliances is falling, and the investment in the end-use heating appliances is also decreasing, even as its penetration is increasing. With the carbon target tightens, natural gas-based heating will decrease significantly, leading to the lower operating cost in the heat sector from £45.5 billion in 2020-2024 to £0.3 billion in 2050-2054.

The cost of the hydrogen infrastructure is dominated by the investment cost of gas reforming plants. The hydrogen infrastructure investment is £186.0 billion, split between investment in production plants (£171.3 billion) and £13.9 billion in H2S. The cost of hydrogen transmission is around £0.8 billion. From 2030 onwards, the newly sold vehicles will be all HFCVs based on the assumption in this study. The hydrogen demand will increase significantly from 2030, the operating cost of hydrogen will gradually increase and reach £135.3 billion in 2050-2054. The overall operational cost for producing hydrogen by natural gas is £603.0 billion (23.0% of the total cost). It is worth noting that the DAC deployment will be required in 2050 to achieve the final net-zero carbon target.

For the hydrogen pathway, increasing the carbon target in the modelling from 200 g/kWh in 2020 to 0 g/kWh in 2050, increasing annual system cost from £49.0 billion/year in 2020 to £89.5 billion/year in 2050.

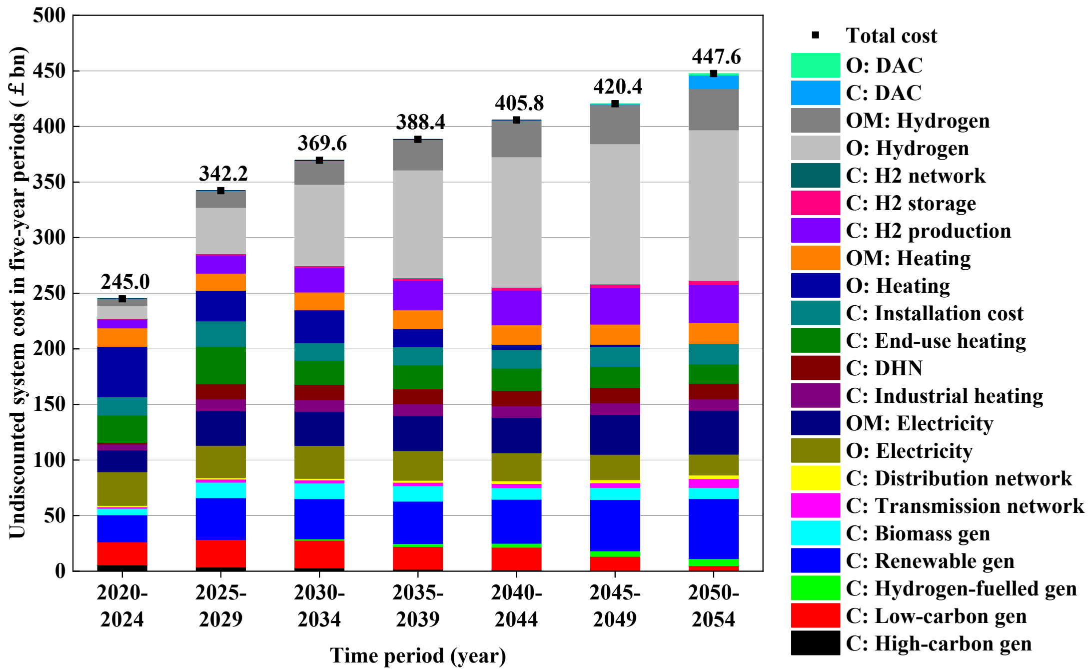

Figure 8.1. Decomposed five-year undiscounted system cost to 2054 in the hydrogen pathway.

The optimal generation capacity and production for the hydrogen pathway are shown in Figure 8.2. The existing generation capacity can be used until the end of its technical lifetime and gradually substituted by the low-carbon and RES generation. Due to the lower full load hour of RES generation, total installed capacity will increase in the process of decarbonisation, from 72.0 GW (2020) to 113.3 GW (2050).

The expected growth in the base electricity demand and the integration of EV and EL push up electricity demand by a factor of 1.5 in 2050, leading to an increasing amount of electricity generation capacity. For the conventional high-carbon generation, the CCGT contributes 43.2% of annual generation from 2020 to 2024 when the carbon target is 200 g/kWh. By 2045, most of the existing high-carbon generation capacity will reach the end of their technical lifetime and be substituted by the low-carbon and RES generation.

The capacity of wind, hydrogen-fuelled generation increases substantially with the tightening of carbon targets. During the initial steps of transition, nuclear and gas-ccs generation contribute to the stable generation economically. However, later the hydrogen-fuelled generation increases significantly due to the projected cost reduction of hydrogen production technologies.

From 2020 to 2024, bioenergy contributes only a small proportion (5.7%, 19.5 TWh) due to its high operating cost. From 2025 onwards, when the carbon target is tightened to 100g/kWh, CCGT generation falls significantly, while biomass energy rises to the high level (55.5 TWh) and remains stable in the following periods, using all potential bioenergy sources to provide negative emissions to offset positive emissions from other sectors. However, the use of bioenergy is limited by sustainable biomass raw material potential.

The share of hydropower (3.5 TWh) in the total electricity generation is limited due to the technical potential of hydropower dams. The hydropower run-of-river plants used in this study cannot compete with other RES, so its expansion is not considered in this study.

During the later years of the electricity sector transition, wind power becomes the dominating technology, representing more than half of total electricity generation. The need for nuclear capacity is small as most hydrogen can be produced cost-effectively by natural gas. The optimal share of hydrogen-fuelled generation increases to 16.8% of total electricity generation, and the sum of nuclear and gas-ccs generation decrease to 3.5%.

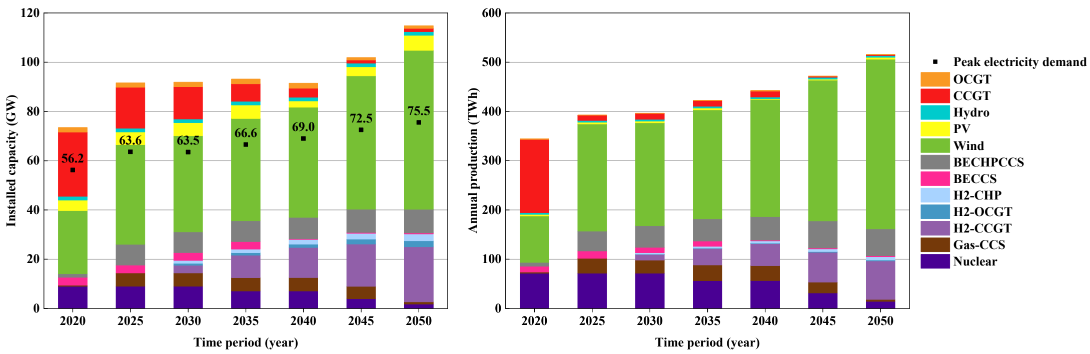

Figure 8.2. The installed capacity of electricity generation technologies (left) and electricity generation (right), as well as the peak electricity demand in the hydrogen pathway.

The heat sector's transition in the hydrogen pathway will demand a fast growth deployment in HB to substitute the existing natural gas-based heating appliances. Figure 8.3 shows the installed capacity for heat supply and heat generation for every five-year time step for the transition period from 2020 to 2054, adopting the hydrogen pathway. The end-use heating system dominates the heat supply in the hydrogen pathway. In 2020, most of the heat is generated from natural gas by NGBs. In 2050, 94.7% is supplied by hydrogen. The district heating using biomass fuel-based structure but only contributes around 11% market share from 2025. This is due in part to the high capital cost of DHN.

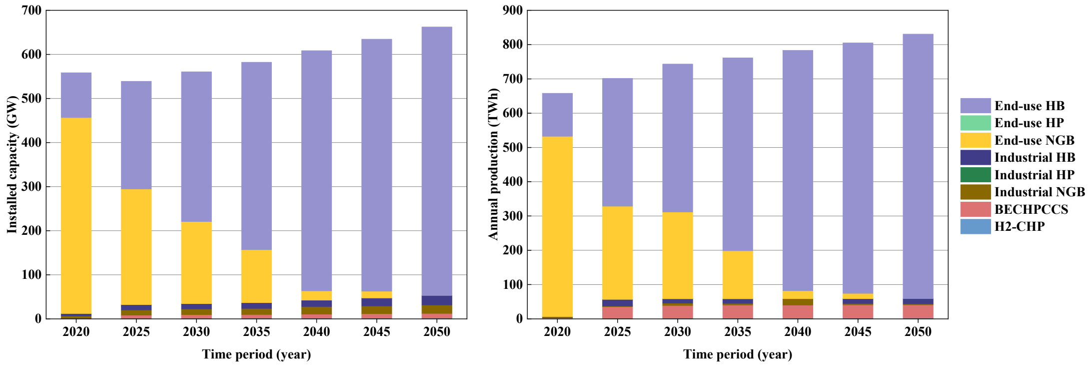

Figure 8.3. The installed capacity of heating technologies (left) and heat production (right) in the hydrogen pathway.

Figure 8.4 shows the penetration level of different heating technologies in the hydrogen pathway. It can be observed that the decarbonisation speed of the heat sector is much slower compared to that in the electricity sector. The penetration level of district heating remains steady after 2025. In 2050 HB will become the dominant end-use heating solution and replace all the NGBs.

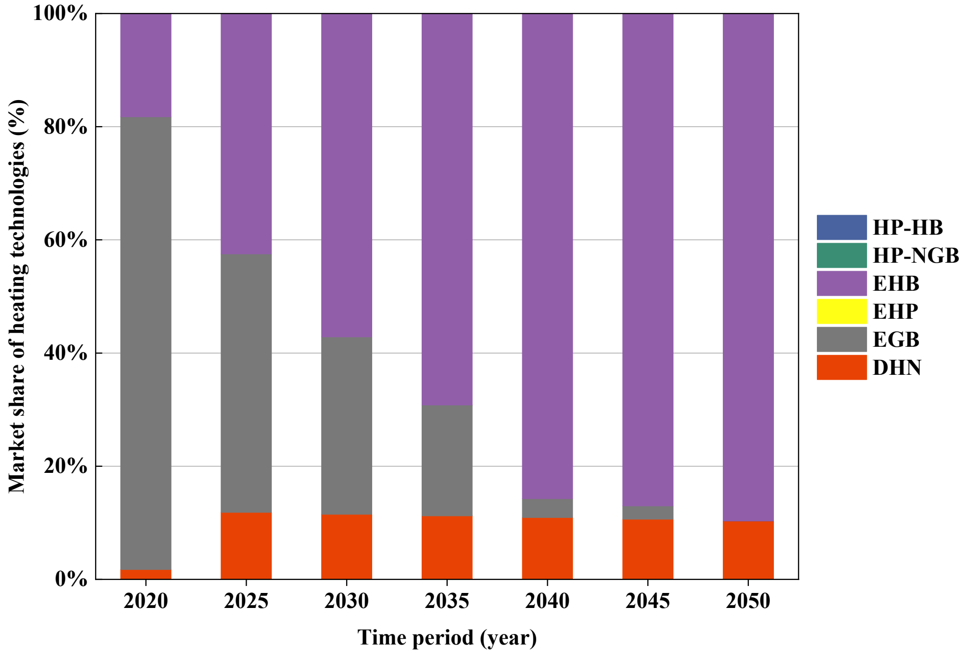

Figure 8.4. The market penetration of different heating technologies in hydrogen pathway.

The market penetration level of different types of vehicles in the hydrogen pathway is illustrated in Figure 8.5. The transport sector decarbonisation transition leads to the growth of hydrogen demand significantly in the hydrogen pathway. Starting from nearly 100% fossil fuel-based, the transport sector transitions to a hydrogen-based sector from 2030.

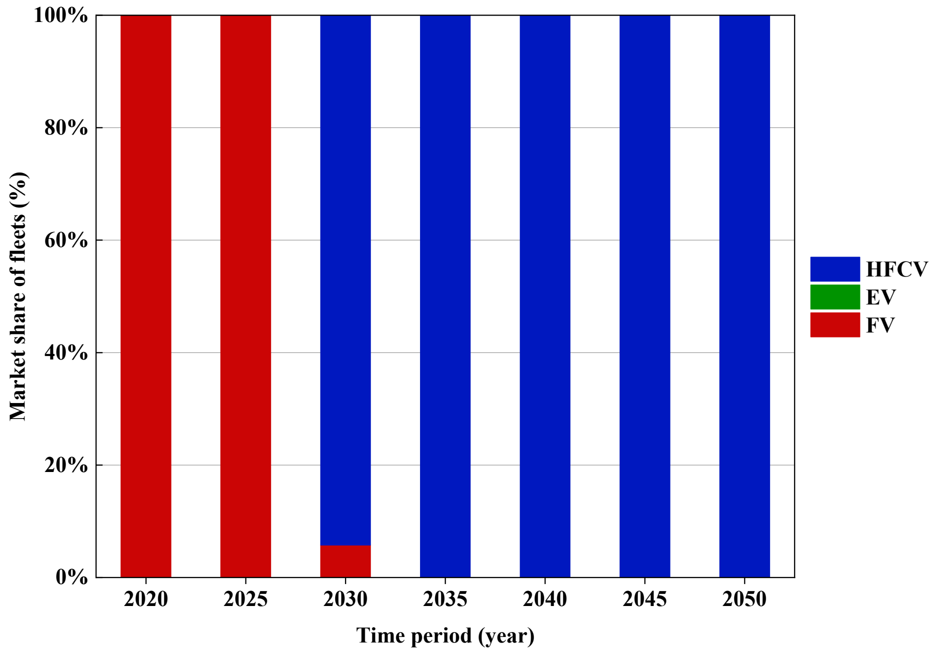

Figure 8.5. Market penetration of different fleets in hydrogen pathway.

The deployment of hydrogen infrastructure, including the capacity of hydrogen production plants, H2S, and the annual hydrogen demand in the hydrogen pathway, is listed in Table 8.9.

It is observed that the GHR-ATR has a much higher capacity than EL because it has an economic advantage and does not require additional expansion of electricity generation capacity. BHCCS capacity is nearly zero due to its high capital cost and lower efficiency. As carbon targets continue to tighten, GHR-ATR's capacity increases dramatically due to its low-carbon feature. After 2020, the penetration level of hydrogen integration in both heat and transport sectors is expected to increase significantly. The newly-built H2S reaches the maximum limits in all the periods, indicating the vital role of H2S in balancing the variable hydrogen demand.

Table 8.9. Hydrogen infrastructure deployment and hydrogen demand in the hydrogen pathway.

	2020	2025	2030	2035	2040	2045	2050
EL capacity (GW)	0.5	8.0	8.1	8.1	8.1	8.1	7.7
GHR-ATR capacity (GW)	30.0	60.0	86.6	110.0	134.7	144.6	154.2

BHCCS capacity (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.1
H2S capacity (GWh)	180.0	360.0	540.0	720.0	900.0	1080.0	1260.0
H_2 demand (TWh)	133.9	412.5	623.9	817.9	981.0	1054.3	1130.7

Figure 8.6 shows the carbon emissions mix in the hydrogen pathway on a five-yearly basis. As expected, the hydrogen pathway can deliver significant carbon emissions reduction. The carbon emissions intensity follows the trajectory defined in this study, falling to 50 g/kWh in 2030, 10 g/kWh in 2045 net-zero by 2050, remaining at this level subsequently.

The heat and transport sectors are nearly carbon neutral by 2045 and 2030, respectively. Their decarbonisation speed is much lower than that in the electricity sector, whose carbon emissions are reduced from 47.8 $MtCO_2$/year in 2020 to 4.7 $MtCO_2$/year in 2025. This is partly due to the relatively high investment in low-carbon heating equipment and zero-emission vehicles. This is also due to the diversity of low carbon technologies in the electricity sector and their longer lifetimes, which are more well-established and can be applied relatively early to offset carbon emissions from other energy sectors.

In 2050, overall annual carbon emissions are reduced by a significant amount from 255.1 $MtCO_2$/year in 2020. Near carbon-neutral is achieved in the electricity, heat and transport sectors, with the primary carbon emissions coming from low-carbon hydrogen production technology (e.g., GHR-ATR). This part of the emissions will need to be offset by DAC integration. As mentioned above, the biomass utilisation level becomes high from 2025, which can provide near 50 $MtCO_2$/year negative carbon emissions, remaining at this level subsequently.

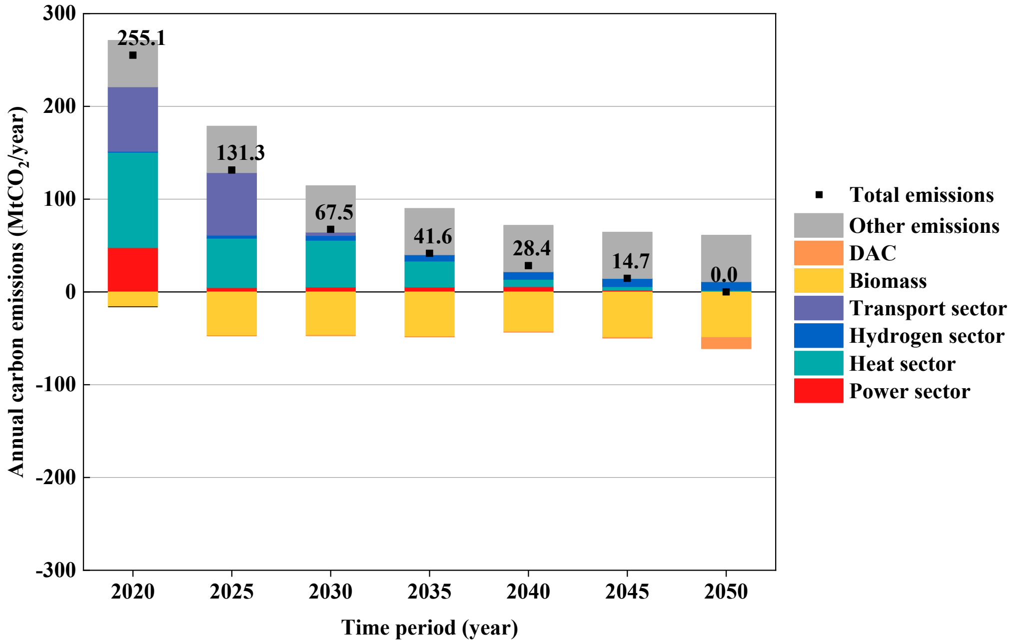

Figure 8.6. Carbon emissions mix in the hydrogen pathway.

8.3.2. Analysis of Electric Pathway

Total system cost over the time horizon under the electric pathway is shown in Table 8.10. The table indicates a significant rise in annual undiscounted cost towards the 2025-2029 period, which subsequently level off. This is driven by the projected tightening of carbon targets from 200 g/kWh in 2020 to 100 g/kWh in 2030. Various low-carbon technologies such as RES generation, biomass-based applications and electrification of heat and transport sectors begin to deploy to decarbonise various energy sectors. The cumulative discounted system cost of the electric pathway is £1443.3 billion, comprising the cost of electricity sector expansion (£865.5 billion), the cost for the heat sector (£556.0 billion). The DAC cost is only £21.9 billion.

Table 8.10. Total system cost to 2054 in the electric pathway.

Five-year period	2020-2024	2025-2029	2030-2034	2035-2039	2040-2044	2045-2049	2050-2054	2020-2054

System cost £bn (undiscounted)	237.9	324.9	360.6	387.0	402.1	430.4	454.9	2597.7
System cost £bn (discounted)	222.3	255.6	238.9	215.9	188.9	170.2	151.5	1443.3

The cumulative undiscounted system cost in five-year periods to 2054 for the electric pathway is shown in Figure 8.7. Total system costs are dominated by investment costs in installing low-carbon and RES generation and upgrading electricity networks and the investment costs at the household level to install HP to replace NGB. In moving towards the net-zero target, electricity generation capacity expansion primarily happens in gas-ccs and RES generation. Most of the electricity operating cost is attributed to the cost of the gas-ccs generation, which remains at a stable level during the operation horizon. The investment required in gas-ccs and RES generation continues to increase as electrification deeply decarbonises the heat and transport sectors, with investment in gas-ccs and RES generation reaching £196.8 billion and £501.5 billion by 2050 respectively. The heat and transport sectors will be gradually electrified to meet the carbon targets in each phase, which leads to the reinforcement of electricity distribution networks. It can be observed that system cost associated with the distribution network will be incurred in each period, totalling up to £82.8 billion by 2050.

In the heat sector, the investment costs in district heating are relatively low. The key challenge for electrification of heating demand using HP is the comparatively high capital cost relative to NGB and the associated need to expand the electricity sector to meet the growth in peak demand. In the process of heat sector electrification, HP is deployed in the 28.6 million households over 2020-2050. The overall investment costs in end-use heating appliances are £493.2 billion. Due to the presence of hybrid heating technology in this study, many existing NGBs will be converted to HP-Bs. With the carbon target tightens, natural gas-based heating will decrease, leading to the lower operating cost in the heat sector from £51.3 billion in 2020-2024 to £13.6 billion in 2050-2054.

It is worth noting that DAC will be deployed early from 2045 onwards to meet carbon emission targets. This can be explained by the fact that DAC will be a cost-effective option after 2045 compared to the electrification option.

For the electric pathway, increasing the carbon target in the modelling from 200 g/kWh in 2020 to 0 g/kWh in 2050 increases the annual system cost from £47.6 billion/year in 2020 to £91.0 billion/year in 2050.

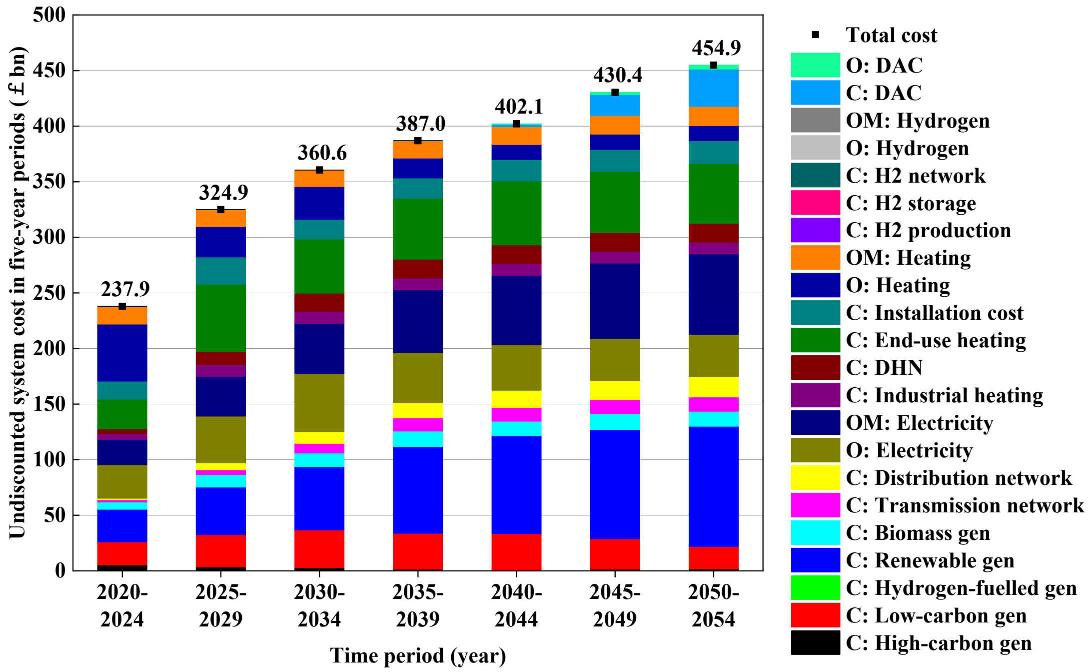

Figure 8.7. Decomposed five-year undiscounted system cost to 2054 in the electric pathway.

The electricity sector's transition will demand a fast growth in RES generation capacity to substitute the existing ageing electricity generation capacity and satisfy the additional electricity demand from electrical heating and transportation. The optimal generation capacity and production for the electric pathway are shown in Figure 8.8. The use of electricity for heating and transport, pushing up electricity demand by doubling over the next 20 years. During the initial steps of transition, wind power and gas-ccs generation are economically feasible. From 2040 onwards, PV generation becomes the least-cost energy source due to the projected cost reduction of PV capital cost. In 2050, the PV capacity increases significantly and reaches 64.4 GW by 2050; the optimal share of RES generation rises to 78.6%. Similar to the hydrogen pathway, the share of hydropower and biomass in the electricity generation is also limited by their natural conditions, and both reach their technical potential from 2025. It is important to highlight that the additional 7.4 GW of CCGT will be installed to balance the system in 2040 as all existing CCGT generation capacity is decommissioned by 2040. This is because DAC becomes cost-effective with the significant cost reduction, which will provide negative emissions and mitigate decarbonisation pressures in other energy sectors.

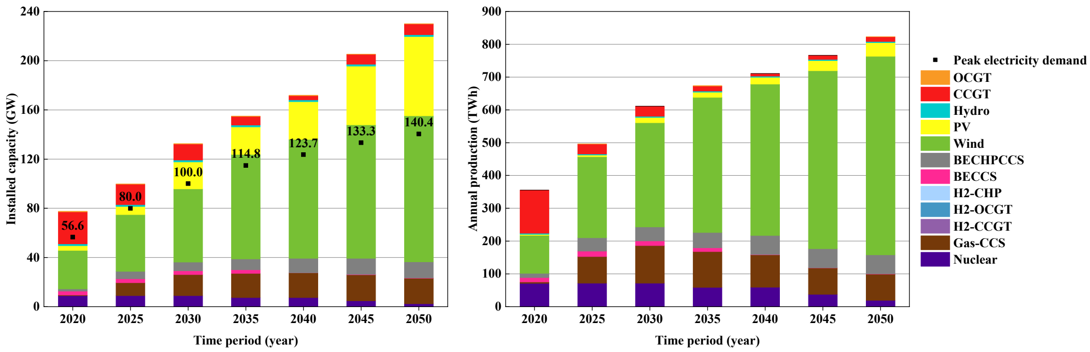

Figure 8.8. The installed capacity of electricity generation technologies (left) and electricity generation (right), as well as the peak electricity demand in the electric pathway.

Figure 8.9 shows the installed capacity for heat supply and heat generation for every five-year time step adopting the electric pathway. The electrification of heating demand using HP, which can operate with high energy efficiency. Thus, even the total capacity of HP is small. It contributes more than half of heat demand since 2025, up to 77.1% of total heat production in 2050. Due to the presence of hybrid heating technology, NGB capacity remains high even as carbon targets are being tightened. This is because the RES generation is limited during peak heat demand. The high efficiency of fossil fuel (e.g., natural gas) to heat conversion make natural gas-based heating more competitive. Therefore, the NGB is used for providing additional heat during the peak heat demand. The heat delivered by NGB constitutes around 15% in 2040, remaining at this level subsequently. The penetration level of DHN in the electric pathway is around 16% since 2030. Industrial HP becomes the primary source for district heating due to its high and stable efficiency.

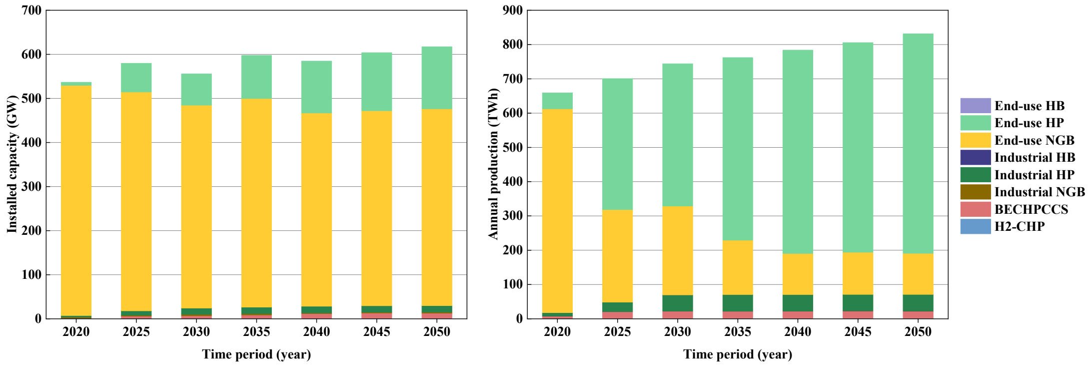

Figure 8.9. The installed capacity of heating technologies (left) and heat production (right) in the electric pathway.

Figure 8.10 shows the penetration level of different heating technologies in the electric pathway. It can be observed that all the stand-alone end-use NGB will be retired in 2030. The hybrid heating technology (e.g., HP-B) is the dominant low-carbon heating solution in the electric pathway. Around 77% of households in the GB are equipped with HP-B for heating use. However, when the carbon target tightens to 20 g/kWh, the HP-B market share decreases due to the further decarbonisation requirement in the heat sector. Meanwhile, the market share of the stand-alone end-use HP increases, reaching 18.5% in 2050.

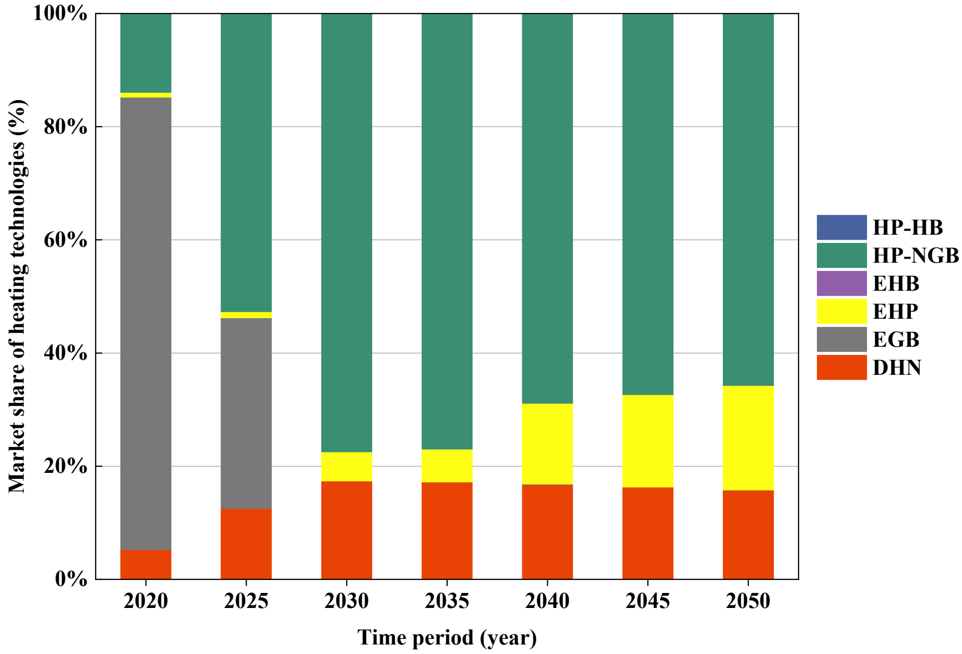

Figure 8.10. The market penetration of different heating technologies in the electric pathway.

The market penetration level of different types of vehicles in the electric pathway is illustrated in Figure 8.11. From 2025, all new sale vehicles will be EVs, and it dominates the market when all the FVs are retired in 2030.

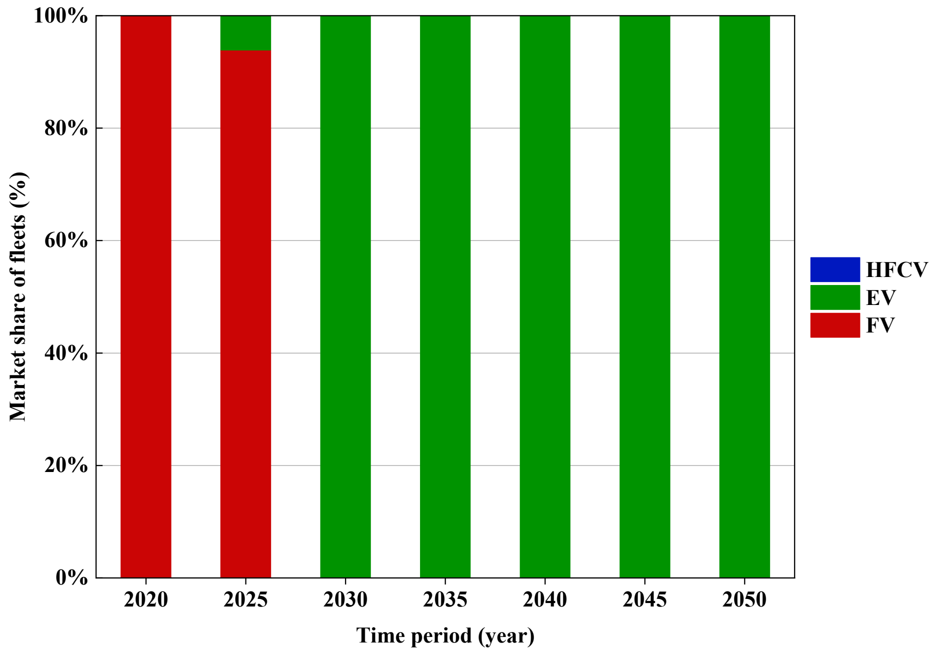

Figure 8.11. Market penetration of different fleets in the electric pathway.

Figure 8.12 shows the carbon emissions mix in the electric pathway on a five-yearly basis. As expected, the electric pathway can deliver significant carbon emissions reduction. The carbon emissions intensity follows the trajectory defined in this study, falling to 50 g/kWh in 2030, 10 g/kWh in 2045 net-zero by 2050, remaining at this level subsequently. The transport sector is carbon neutral by 2030.

In 2025, the electricity and heat sectors achieve significant carbon reduction, from 41.5 $MtCO_2$/year to 12.6 $MtCO_2$/year and from 115.9 $MtCO_2$/year to 52.6 $MtCO_2$/year. This is because the decarbonisation of the transport sector will not be a priority from the economic point of view due to EV's higher capital cost compared to FV. In order to meet the carbon target, the electricity and heat sector must achieve substantial carbon reduction. Decarbonisation for the heat sector will bring extra electricity demand for the electricity sector, leading to more significant carbon reduction pressure in the electricity sector. Therefore, the electricity sector needs to achieve low-carbon generation earlier than the heat sector, thus providing the basis for decarbonisation for other energy sectors. This is also due to the diversity of low carbon technologies in the electricity sector can also make it easier to achieve carbon reductions compared to other energy sectors.

In 2030, it can be seen that carbon emissions from the electricity and heat sectors are almost the same as in the previous period. This is due to the transport sector becomes carbon neutral in 2030. The carbon reduction targets for this period are mainly achieved through the complete decarbonisation of the transport sector.

In the following steps, the electricity sector's carbon emissions decrease gradually but increase slightly in 2050. The heat sector's carbon emissions reduce to 23.3 $MtCO_2$/year in 2040 and subsequently remain at this level. Negative emissions from biomass and DAC offset the carbon emissions from the electricity and heat sectors from 2035 to 2054. It indicates that it would be more cost-effective to use DAC to meet carbon targets than further decarbonise the electricity and heat sectors during these periods in the electric pathway.

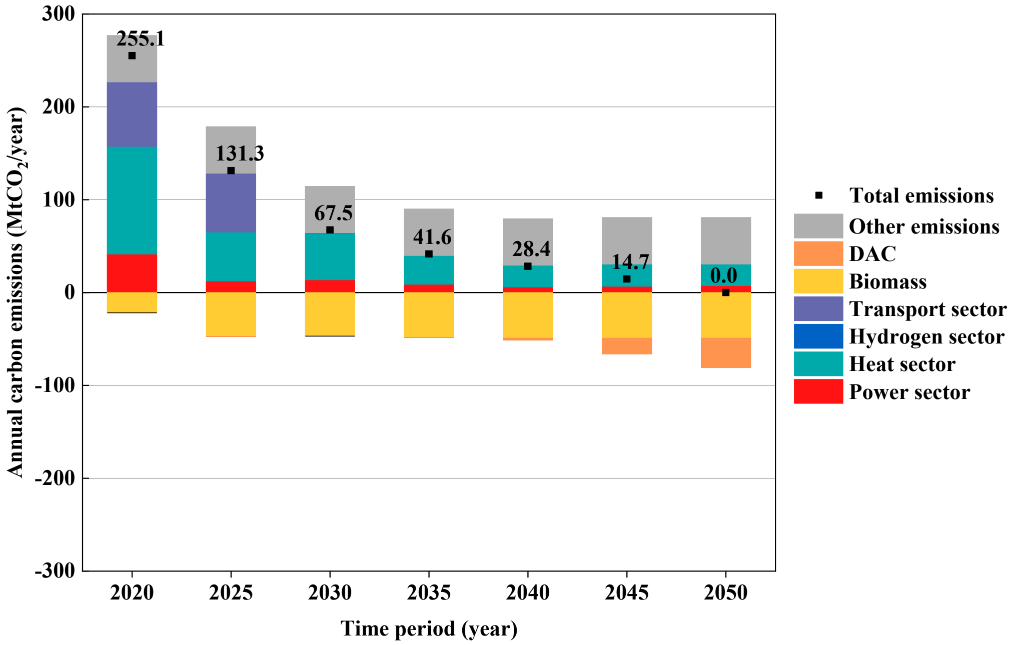

Figure 8.12. Carbon emissions mix in the electric pathway.

8.3.3. Analysis of Hybrid Pathway

Total system cost over the time horizon under the hybrid pathway is shown in Table 8.11. The table also indicates a significant rise in annual undiscounted cost towards the 2025-2029 period, which subsequently level off. The cumulative discounted system cost of the hybrid pathway is £1398.3 billion, comprising the cost of electricity sector expansion (£730.6 billion) and the heat sector cost (£501.9 billion). The total hydrogen infrastructure investment and operation cost are £162.9 billion. The DAC cost is only £2.8 billion.

Table 8.11. Total system cost to 2054 in the hybrid pathway.

Five-year period	2020-2024	2025-2029	2030-2034	2035-2039	2040-2044	2045-2049	2050-2054	2020-2054

System cost £bn (undiscounted)	238.9	320.6	356.6	371.5	382.6	400.3	423.7	2494.3
System cost £bn (discounted)	223.3	252.3	236.3	207.2	179.7	158.3	141.1	1398.3

The cumulative undiscounted system cost in five-year periods to 2054 for the hybrid pathway is shown in Figure 8.13. The system costs in the hybrid pathway are dominated by investment costs in RES generation and the investment costs at the household level to install low-carbon heating appliances. In moving towards the net-zero target, generation capacity expansion primarily happens the RES generation (£482.2 billion). As high-carbon generation options are progressively phased out, the electricity operating cost is decreasing. The heat and transport sectors will be gradually electrified to meet the carbon targets in each phase, which leads to the reinforcement of electricity distribution networks (£63.9 billion).

In the heat sector, the investment cost in district heating is also relatively low and mainly takes place after 2030. The overall investment cost in end-use heating appliances is £438.6 billion. Due to the presences of new hybrid HP and HB technology in this study, a large part of NGB will be replaced, leading to the lower operating cost in the heat sector from £50.4 billion in 2020-2024 to £1.8 billion in 2050-2054.

The cost of the hydrogen infrastructure is dominated by the investment cost of gas reforming plants. The hydrogen infrastructure investment is £68.5 billion, split between investment in production plants (£58.0 billion) and £9.9 billion in H2S. The cost of hydrogen transmission is around £0.5 billion. The production of hydrogen is mainly based on natural gas in the hybrid pathway and consumes natural gas at £197.2 billion. It is worth noting that the DAC deployment will be required in 2050 to achieve the final net-zero carbon target. It is worth noting that the system is relatively lightly dependent on the DAC due to the introduction of a variety of low carbon technologies in the hybrid pathway, costing only £8.3 billion.

For the hybrid pathway, increasing the carbon target in the modelling from 200 g/kWh in 2020 to 0 g/kWh in 2050 increases the annual system cost from £47.8 billion/year in 2020 to £84.7 billion/year in 2050.

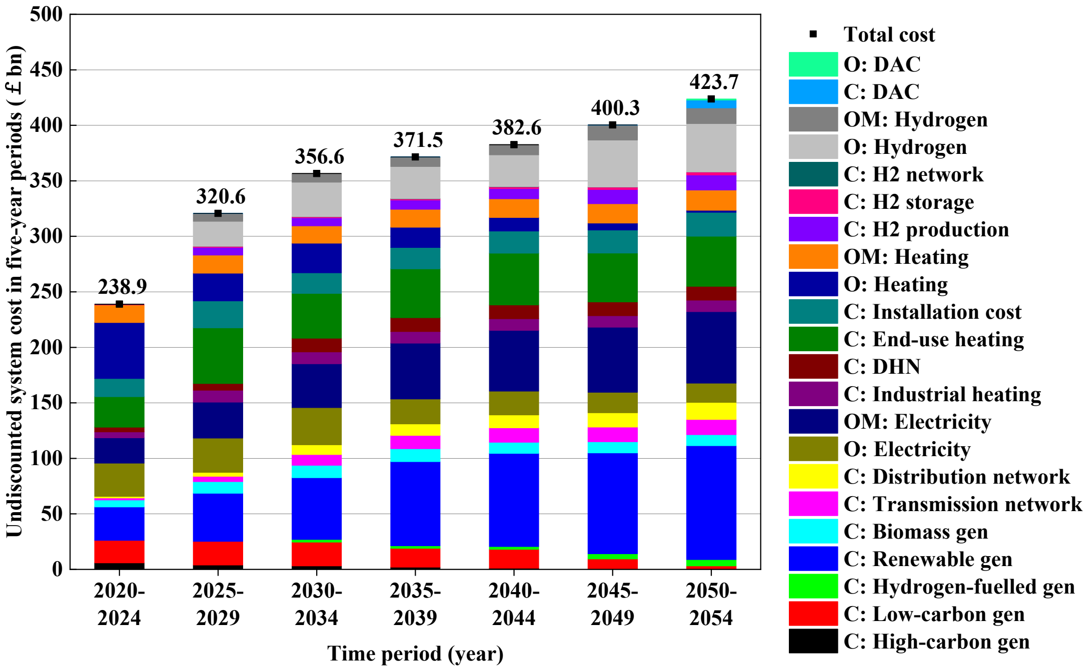

Figure 8.13. Decomposed five-year undiscounted system cost to 2054 in the hybrid pathway.

The optimal generation capacity and production for the hybrid pathway are shown in Figure 8.14. The existing generation capacity can be used until the end of its technical lifetime and gradually substituted by the hydrogen-fuelled CCGT, BECHPCCS and RES generation. It is worth noting that gas-ccs is not primarily invested in, and OCGT is built 4.1 GW in 2020 to provide backup generation. This is because the hybrid pathway reduces the requirement for electrification of other energy sectors, thereby reducing the need for firm low-carbon generation. By 2035, most of the existing BECCCS generation capacity will have reached the end of its technical life. At then, biomass will be used mainly for BECHPCCS to generate electricity and heat simultaneously. The capacity of wind, hydrogen-fuelled generation increases substantially with the tightening of carbon targets. In 2050, wind power, hydrogen-fuelled generation and bioenergy become the dominating technology, representing 75.1%, 11.6% and 7.4% of total electricity generation.

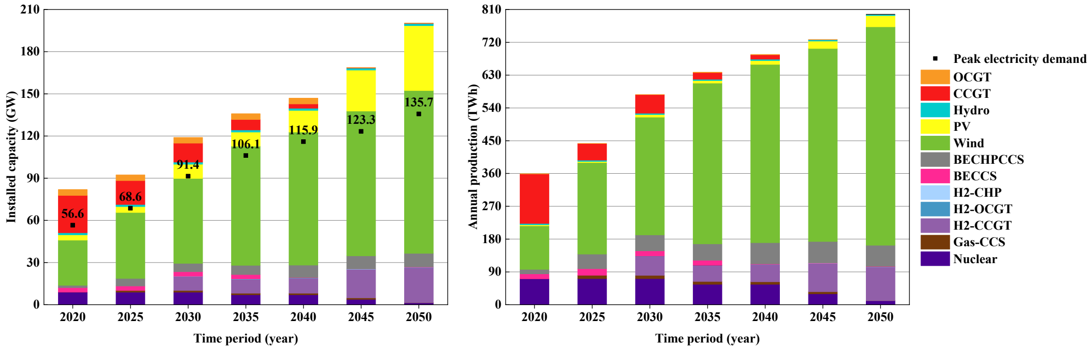

Figure 8.14. The installed capacity of electricity generation technologies (left) and electricity generation (right), as well as the peak electricity demand in the hybrid pathway.

The electric pathway analysis in the previous subsection highlights the considerable additional costs associated with HP and the electricity distribution network reinforcement. By installing the HP alongside NGB within a single household, representing the opportunity to meet the majority of heat demand using HP, but applying NGB during the peak time. The potential benefits of hybrid heating are apparent. Firstly, it can reduce the need for HP since it is not required to meet peak demand, reducing the cost in both the heat and electricity sectors. Secondly, replacement of NGB can be avoided as gas-fired boilers can provide high heating temperatures when needed, while lower temperatures are sufficient for most of the year. However, the critical disadvantage of hybrid HP-B is demonstrated in the electric pathway, which delivers a less profound level of decarbonisation for the heat sector insofar as NGB remains used to meet some fraction of heat demand. Therefore, a novel hybrid heating technology combining HP with HB is proposed in the hybrid pathway to mitigate the negative impacts of each of these factors.

Figure 8.15 shows the installed capacity for heat supply and heat generation for every five-year time step adopting the hybrid pathway. With the gradual tightening of carbon targets, NGB capacity is dropping, and HP and HB capacity are rising. From 2035 onwards, even though HB has a much higher capacity than HP, the bulk of the heat demand (e.g., more than 50%) is supplied through HP, and NGB and HB providing only a small proportion of the heat demand especially during peak periods.

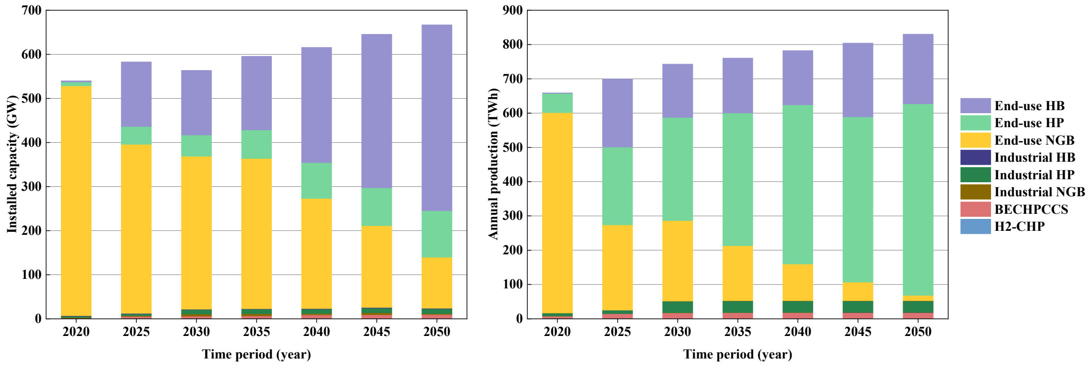

Figure 8.15. The installed capacity of heating technologies (left) and heat production (right) in the hybrid pathway.

Figure 8.16 shows the penetration level of different heating technologies in the hybrid pathway. In 2030, hybrid heating technologies are dominant, with HP-B and HP-HB holding 58.4% and 24.7% of the market share, respectively. However, as carbon emission targets continue to tighten, the HP-B becomes a limit to the depth of further decarbonisation in the heat sector. HP-HB begins to overtake HB-NGB in penetration level and holds a 41.1% market share over HP-B's 39.3% in 2040 and still increasing in subsequent phases.

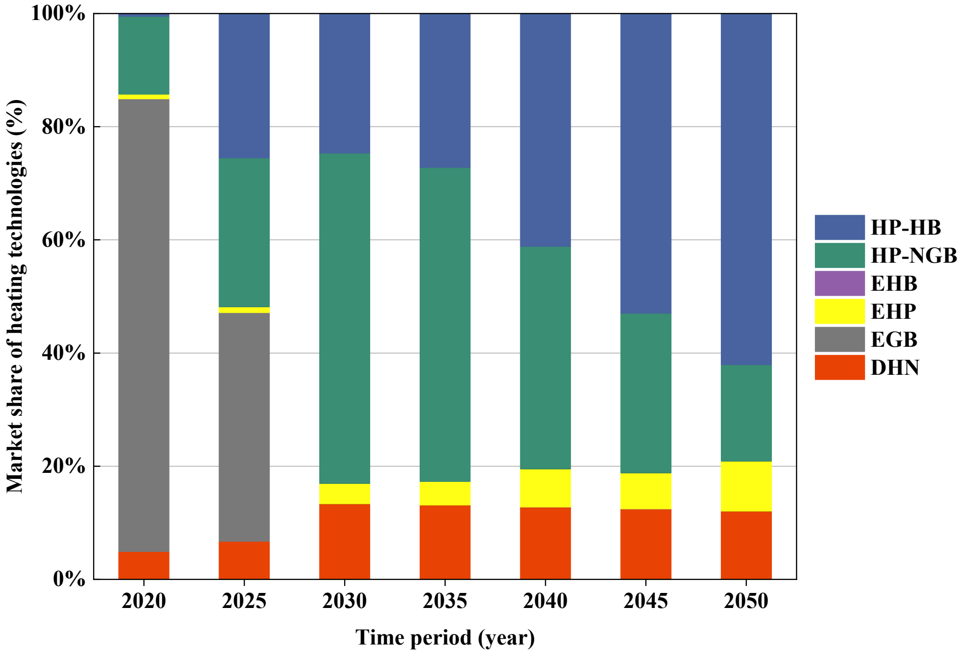

Figure 8.16. The market penetration of different heating technologies in the hybrid pathway.

The market penetration level of different types of vehicles in the hybrid pathway is illustrated in Figure 8.17. It can be observed that the transition of the transport sector in the hybrid pathway is similar to that in the electric pathway. This is due to that the capital cost of vehicles has a decisive impact on their market shares. The capital cost of HFCV is higher than EV, leading it is not competitive with EV in the hybrid pathway.

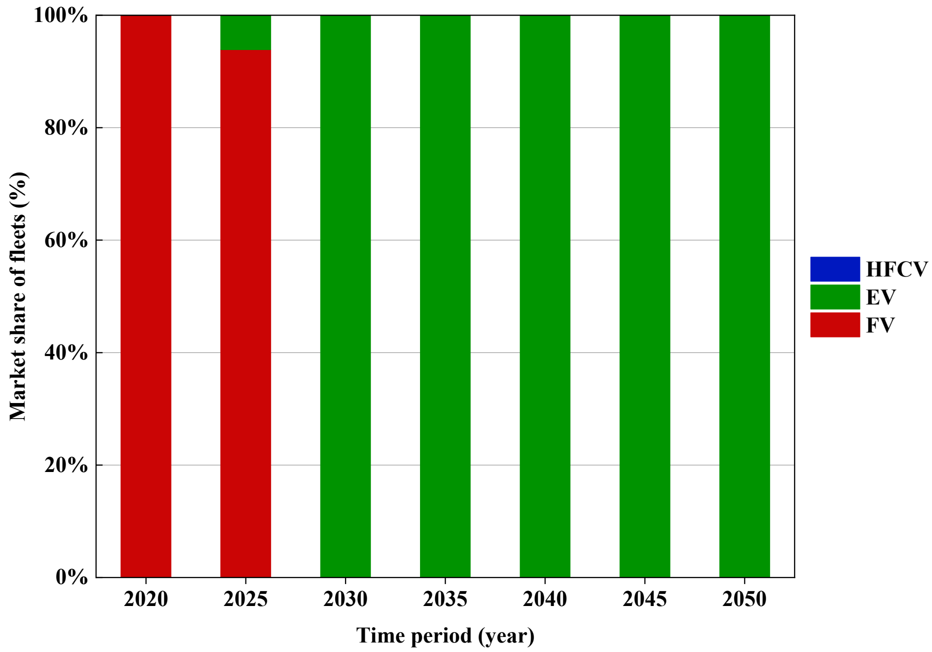

Figure 8.17. Market penetration of different fleets in the hybrid pathway.

The deployment of hydrogen infrastructure, including hydrogen production plants, H2S, and the annual hydrogen demand in the hybrid pathway is listed in Table 8.12. Due to the high capital cost of HFCV, hydrogen is mainly used for electricity and heat sectors in the hybrid pathway based on the assumptions in this study. In 2025, hydrogen-fuelled generation is unavailable, and NGB dominates the heat sector. The hydrogen demand is relatively low. It is worth highlighting that the hydrogen demand of 1.1 TWh in 2025 requires 151.5 GWh of H2S to balance the variability. H2S is used to provide a buffer as the GHR-ATR runs continuously and provides the discharge for meeting the peak demand. Therefore, even the capacity of GHR-ART is relatively small (0.1 GW), it still needs 151 GWh hydrogen storage for interseasonal storage.

The hydrogen demand in 2035 and 2040 is slightly lower than in the previous period, but the hydrogen production capacity and storage increase to cover peak hydrogen demand. From 2045 onwards, the demand for hydrogen increases again, and the capacity of the GHR-ART is increased to produce the majority of hydrogen. Conversely, the capacity of EL remains the same.

In summary, the GHR-ATR is suitable for producing large volumes of base hydrogen demand, while the EL will be used in association with the RES, priority to handle a small part of hydrogen demand.

Table 8.12. Hydrogen infrastructure deployment and hydrogen demand in the hybrid pathway.

	2020	2025	2030	2035	2040	2045	2050
EL capacity (GW)	0.0	0.5	0.5	5.3	7.3	7.6	7.6
GHR-ATR capacity (GW)	0.1	30.1	31.3	31.3	33.6	53.9	59.2
BHCCS capacity (GW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H2S capacity (GWh)	151.5	331.5	332.3	425.4	605.3	785.3	965.3
H_2 demand (TWh)	1.1	208.6	254.5	245.8	248.2	360.3	372.2

Figure 8.18 shows the carbon emissions mix in the hybrid pathway on a five-yearly basis. As expected, the hybrid pathway can deliver significant carbon emissions reduction. The carbon emissions intensity follows the trajectory defined in this study, falling to 50 g/kWh in 2030, 10 g/kWh in 2045 net-zero by 2050, remaining at this level subsequently. The transition of carbon emissions reduction in each energy sector is similar to the hydrogen pathway. The diversity of low carbon technologies throughout the system in the hybrid pathway reduces reliance on DAC.

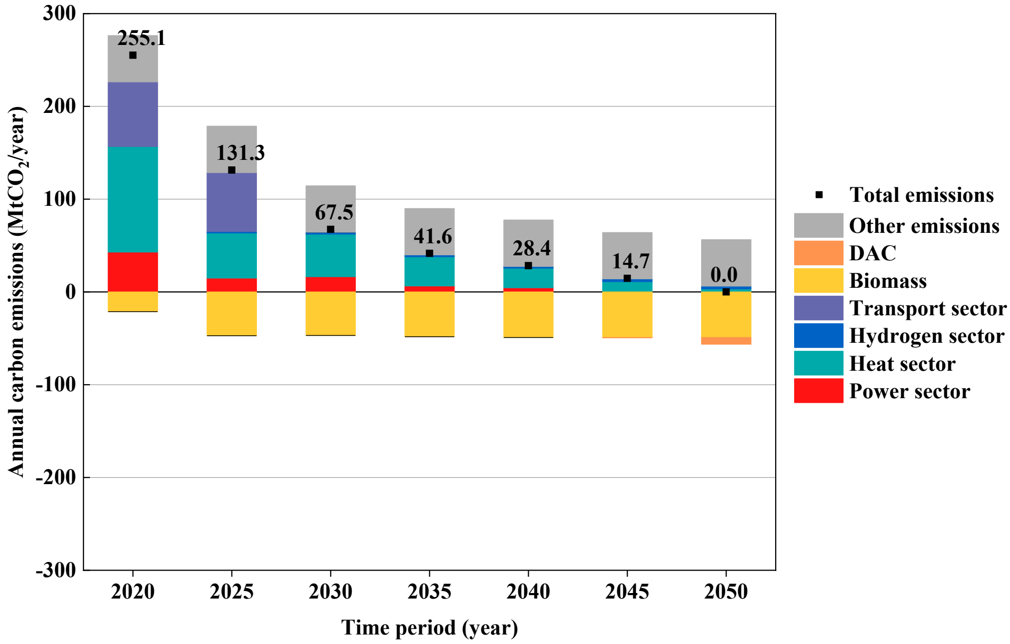

Figure 8.18. Carbon emissions mix in the hybrid pathway.

8.3.4. The Impact of Flexibility on Electric Pathway

In all three of the above transition pathways, the electricity sector will have a large amount of RES generation and the electrification of the heating and transport sectors. In order to maintain a resilient, secure and affordable future electricity system, various technologies can provide additional flexibility, such as DSR, energy storage, flexible generation and electricity interconnection, to compensate for the lack of traditional sources of flexibility in the decarbonisation process, such as natural gas-fired generation.

The optimal mix of flexibility technologies depends on their integration cost, performance and availability. It is essential to investigate the impact of the deployment of flexibility technologies on investment decisions and the operation of the energy infrastructure in achieving the net-zero target.

This subsection completes the running of a high-flexibility scenario in which additional flexibility technologies are optimally deployed in the electric pathway to identify the value of flexibility for the transition to the net-zero target for the GB energy system. In this scenario, EES, including BES and DES, are considered. DSR for controlled EV loads is also considered, and a penetration level of 20% is reached in 2020 and increases by 10% every five years to 80% by 2050.

The scenario of the electric pathway presented in subsection 8.3.2 is defined as the low flexibility scenario. Figure 8.19 shows the undiscounted system cost savings for the high flexibility scenario compared to the low flexibility scenario. The total system cost of deploying EES and DSR (£22.1 billion) is significantly less than the major savings from avoided investments in electricity generation (£18.5 billion) and distribution network (£12.3 billion), electricity operation cost (£70.1 billion), costs of heat sector (£19.3 billion) and DAC (£43.9 billion), which are cumulative net savings of £292.7 billion by 2054.

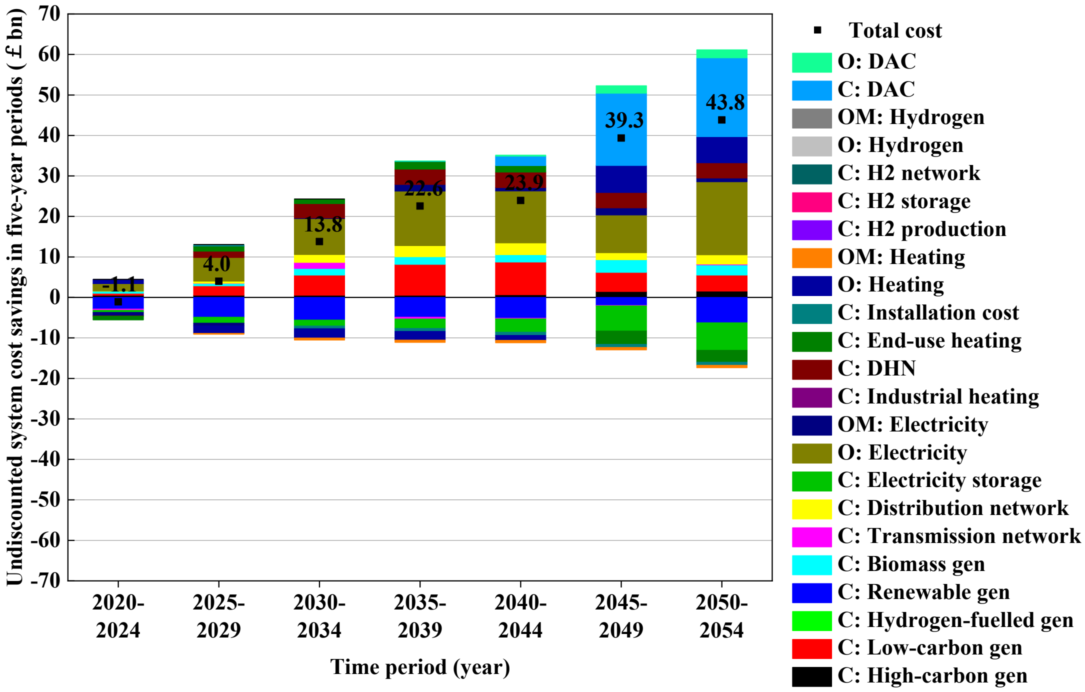

Figure 8.19. Cost differences between the low-flexibility scenario and high-flexibility scenario in the electric pathway cumulative to 2054.

Figure 8.20 illustrates that the deployment of additional flexibility technologies could reduce the need for both high and low carbon generation in the transition to net-zero by 2050 and increase the need for RES generation. EES's presence increases the utilisation of intermittent RES generation, thereby reducing the need for the conventional generation to balance the system. The benefits of flexibility in decarbonising the electricity sector are most pronounced after 2040, when high-carbon generation is virtually absent.

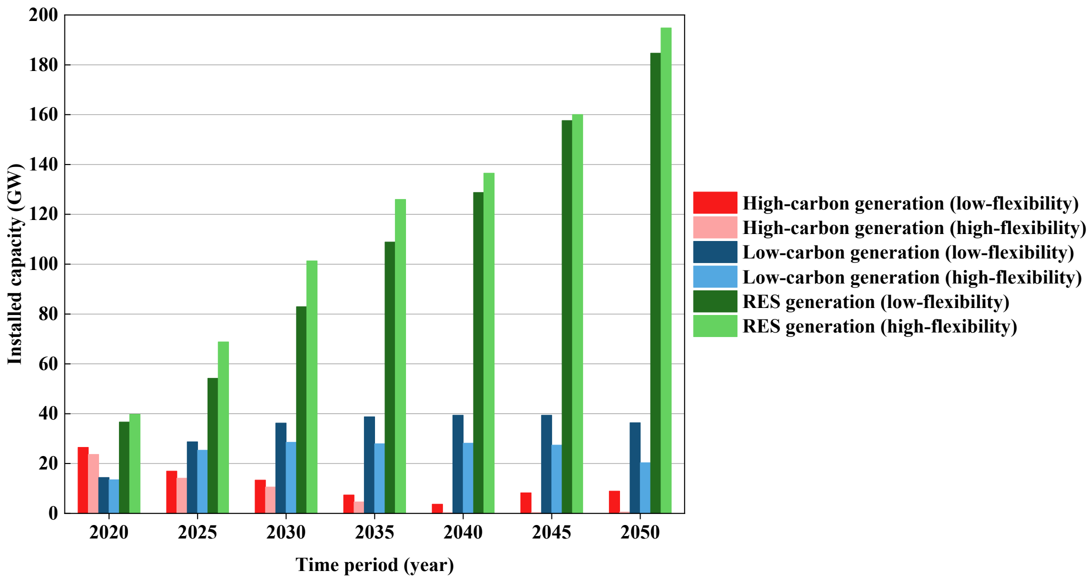

Figure 8.20. The differences in the generation capacity mix between the low-flexibility and high-flexibility scenarios.

Distribution network capacity is primarily driven by peak demand. The need to reinforce the distribution network is determined by demand growth and the electrification of the heat and transport sectors. Growth in distributed generation such as rooftop PV, so the commissioning of DSR and DSE can effectively shift the peak and thus delay reinforcement of the distribution network, thereby deferring the need for additional investment in upgrading capacity.

In addition to reducing investments related to infrastructure in the electricity sector, flexibility also reduces operating costs associated with fuel consumption. The reduction in operating costs is due to the fact that there is a less conventional generation in the system and that the remaining conventional generation is utilised more efficiently.

The results demonstrate that additional flexibility deployment directly impacts key investment decisions in the electricity sector. The electricity sector's decision-making will also indirectly affect the heat and transport sectors' electrification process, particularly the heat sector. Flexibility technologies increase the electricity sector's efficiency by improving the utilisation of generation, thus also increasing the depth of electrification in the heat sector and increasing the deployment of HP in end-use heat supply. The cost savings in the heat sector come mainly from the less deployment of DHN. The additional flexibility could also delay the decision to invest in DAC facilities as increased RES generation would result in additional carbon emissions reductions.

8.4. Policy Recommendations

This subsection provides the relevant policy recommendations based on the modelling results by comparing the three transition pathways and flexibility studies mentioned above.

Firstly, all three pathways need a significant investment in bioenergy generation and RES generation to achieve the net-zero target by 2050. This implies that the electricity supply's decarbonisation should focus on bioenergy and RES generation in the long term. Conventional firm low-carbon capacity, such as nuclear and gas-ccs, is not a priority for deployment in the electricity sector. Increasing the penetration level of RES generation should be accompanied by the additional system flexibility to minimise its system integration cost.

Secondly, all three pathways need to deploy low-carbon heating appliances to decarbonise the heat sector. The hybrid heating technologies are more cost-effective and flexible compared to the stand-alone heating appliance. It is worth noting that the heat sector's decarbonisation speed is much lower than that in the electricity sector in all three pathways. Due to the existence of NETs, the heat sector will not achieve carbon neutrality by 2050. This implies that the decarbonisation of the heat sector should be continued. Policymakers should further develop policy guidance for individual end-users to encourage a shift from natural gas heating to low-carbon heating.

Thirdly, current policies in the UK transport sector are accelerating carbon neutrality in the transport sector. Full electrification of the transport sector will significantly impact the electricity sector, but HFCV is not competitive with EV in the long term. Policymakers should incentivise DSR participation in EV loads to reduce the negative impact on asset investment while creating financial incentives to promote the penetration of HFCV.

Finally, the cross-energy system flexibility will be vital to facilitate a cost-effective transition pathway for the future low-carbon energy system. Energy storage and DSR both have a key role in providing flexibility and can reduce the overall system cost. Policymakers should review different flexibility technologies to find optimal solutions for the deployment of flexibility technologies.

8.5. Conclusions of the Chapter

In the present chapter, the transition to the low-carbon future energy system is designed for three pathways: hydrogen pathway, electric pathway, and hybrid pathway, considering the electricity, heat, and transport sectors, from hydrogen integration to NETs integration.

The results indicate that the net-zero carbon target for GB is achievable in all three pathways by 2050. The hybrid pathway is the most cost-effective under given assumptions, while the cost of the hydrogen pathway is found to the highest cost compared to the other two pathways.

More specifically, the hydrogen pathway reduces the need for investment in the electricity sector but requires more investment in the hydrogen supply chain. The overall investment and operating costs associated with the hydrogen supply chain in the hydrogen pathway exceed the benefits of the lower investment in the electricity sector. The hydrogen integration reduces the requirement for investment in low-carbon electricity generation (£301.3 billion) but needs higher investment and operation costs in hydrogen infrastructure (£481.0 billion) compared to other pathways. A key factor contributing to the higher cost of the hydrogen pathway is that the energy conversion processes involved in the hydrogen pathway, such as hydrogen-fuelled generation, HB and HFCV, are lower than HP and EV, resulting in the lowest energy efficiency of the hydrogen pathway.

Electric pathway requires the highest investment in electricity networks (£73.6 billion), particularly at the distribution level (£40.9 billion), due to increased peak demand from heat and transport electrification. Hydrogen and hybrid pathways have lower network costs than the electric pathway. They can effectively reduce the need for distribution network reinforcement due to the use of NGB and HFCV to support peak heating demand and transport demand.

All three pathways mentioned above require the significant capacity expansion of low-carbon generation and RES to achieve the net-zero carbon target. The largest capacity increase is in the electric pathway, reaching 228.5 GW by 2050, about twice as much as in the hydrogen pathway (113.3 GW). Due to the requirement of various sectors decarbonisation and massive electrification, wind power becomes the backbone of the electricity sector, providing more than half of electricity demand from 2025. It is worth noting that in the hydrogen pathway, the share of hydrogen-fuelled generation in the total generation increased to 16.8%. The sum of nuclear and gas-ccs generation decreased to 3.5%, indicating that the optimal generation mix depends not only on the levelised cost of electricity of the generation technologies but also on all technologies' system integration costs.

There is a need to replace natural gas-based heating appliances in hydrogen and electric pathways for the heat sector transition. Due to the flexibility of hybrid heating technology, the NGB is still used in the electric pathway but with low heating production (operating during high peak heat demand driven by extremely low external temperatures). In the hybrid pathway, HB also can be coupled with HP to provide zero-emission hybrid heating. The proportion of hybrid HP-HB could reach 62.1% by 2050.

Consider the UK policy to ban the sale of petrol-powered vehicles from 2030. Decarbonisation of the transport sector is mainly determined by the capital cost and efficiency of vehicles. In the hybrid pathway, HFCV will still not compete with EV in the assumptions made in this study.

Stricter carbon emission targets increase the reliance on hydrogen integration in the hydrogen and hybrid pathway, and consequently, demand for hydrogen infrastructure increases. The integration of various energy sectors allows for cross-sector and low-cost flexibility, allowing the use of low-cost storage (e.g., H2S) options that perform the same functionality as electricity storage.

Across all pathways, the carbon emissions intensity follows the trajectory defined in this study. The decarbonisation speed of the heat and transport sectors is much lower than that in the electricity sector. This is partly due to the relatively high investment in low-carbon heating equipment and zero-emission vehicles. This is also due to the diversity of low-carbon technologies in the electricity sector, which are more well-established and can be applied relatively early to offset carbon emissions from other energy sectors. The NETs integration is vital to offset the challenging carbon emissions, and the DAC only be a cost-effective decarbonisation option after 2040.

The integration of additional flexibility technologies (i.e., energy storage and DSR) in the electric pathway reduces the system's net cost. It delivers an even lower cumulative undiscounted system cost (£2451.3 billion) than the hybrid pathway (£2494.3 billion). Meanwhile, the flexibility technologies can reduce the capacity requirement for low-carbon generation and DAC facility. It is worth mentioning that all the results are system-specific and depend on the assumptions taken.

Chapter 9. Conclusions and Future Work

This thesis describes a series of MES optimisation model to investigate various decarbonisation strategies for the future energy system, supporting the net-zero carbon target by 2050. Using the proposed MES optimisation models, the cost performance of decarbonisation strategies is compared. The optimal investment and operation plans are identified for the whole energy system in a coordinated manner, maximising the synergy across electricity, heat, and transport sectors. This final chapter summarises the thesis's key contributions and findings, addressing each of the proposed research questions below:

- RQ1: How to evaluate the different strategies for decarbonising the integrated electricity and transport sectors in Great Britain?
- RQ2: What is the role and impact of power-to-gas (P2G) integration in the integrated electricity and transport sectors?
- RQ3: What are the benefits and implications of integrating different hydrogen production technologies into integrated electricity, heat and transport sectors?
- RQ4: How to design the transition pathways for future energy systems in the context of MES to achieve the net-zero target by 2050?

The proposed future work is also discussed at the end of the thesis.

9.1. Summary of Conclusions

9.1.1. Evaluating Strategies for Decarbonising the Transport Sector in Great Britain

The developed single-year modelling framework for the whole system MES optimisation of MES investment is used to answer RQ1, RQ2, and RQ3 through several studies. The findings are summarised as follows:

1) The optimisation model can simultaneously optimise the capacity portfolio and coordinate operation of MES involving: electricity sector infrastructure (generation, electricity network), heat sector infrastructure (district heating infrastructure, end-use heating appliances), transport sector (EV and HFCV) and hydrogen infrastructure (hydrogen production capacity, hydrogen network, H2S), while minimising the overall system cost, considering carbon emissions constraints.

2) Operational flexibility and constraints affect investment decisions; therefore, investment and operation decisions should be optimised simultaneously.

3) Most of the electricity will be supplied by large-scale RES. It requires sufficient flexibility to enable the efficient utilisation of RES. Improving flexibility, e.g., from demand response, will also reduce the need for the firm but high-cost CCGT and OCGT.

4) Demand response and energy storage play an important role.

In Chapter 4, the economic performance of various decarbonisation strategies for the transport sector through the coordinated operation with the electricity sector is evaluated by using the single-year MES model. The studies demonstrate that:

1) Electrification of transport should be carried out with smart charging to reduce its impact (cost) on the electricity system. Depending on the assumptions used, the cost performance of both decarbonisation options is comparable.

2) Integration of hydrogen into the electricity system can provide an alternative, low-cost, low-carbon energy source.

3) There is the potential opportunity for both EVs and HFCVs to co-exist, but this depends on the vehicles' capital cost and fuel efficiency.

4) There is a synergy between the hydrogen used in the electricity and transport sector that can be potentially attractive to be explored further.

5) The use of advanced hydrogen production technologies can also reduce further the cost. The studies also demonstrate a strong interaction across electricity, gas and transport sectors; this indicates the need to coordinate policies and planning across these energy vectors.

As a result, the work was published in a conference paper presented in [82].

9.1.2. Integration of Power-to-Gas and Low-Carbon Road Transport in Great Britain's Future Energy System

In Chapter 5, the synergy across electricity and transport sectors is further explored to improve the value and utilisation of investment, especially in low-carbon technologies across the integrated MES system. The large-scale optimisation model is also developed on the basis of the modelling framework in Chapter 3, which considers the interactions across electricity, transport and hydrogen sectors and is used to determine the optimal solutions for investment and sector-coupling operation in the system, and also investigates the role and impact of P2G integration in the integrated electricity and transport sectors, thus addressing the RQ2. The studies demonstrate that:

1) EV's flexibility brings more economic benefits than other individual decarbonisation strategies.

2) The integration of hydrogen-fuelled generation can reduce the overall system cost by enabling more investment in renewable energy and reduce the need for the firm but high-cost low-carbon generation technologies, particularly nuclear and gas-ccs.

3) The combination of the integration of hydrogen into the electricity and road-transport sector and e-mobility can achieve higher cost savings compared to the individual applications. The savings are higher when the carbon constraint becomes tighter.

4) The integration of P2G can increase wind power capacity. HFCV can be combined with EV to reduce the system implication of increasing peak demand due to road transport's electrification.

5) The business case for HFCV from the system perspective becomes less when EV is smart. It indicates that the flexibility of EV (e.g., load-shifting capability and ancillary services) increases the value of EV and makes it more competitive.

6) From the transport sector perspective, the HFCV can achieve more overall cost-savings if the Smart EV is not available. However, the sensitivity study indicates the flexibility level of EV influences the penetration of HFCV. When the smart EV penetration level increases to 70%, the EV dominates the market.

As a result, the work was published in a journal paper [110].

9.1.3. Integration of Hydrogen into Multi-Energy Systems Optimisation

In Chapter 6, a series of case studies are carried out to investigate the economic benefits and impacts of integrating different hydrogen production technologies into integrated electricity, heat and transport sectors. The studies demonstrate that:

1) Most of the hydrogen should be produced from G2G due to cost reason; combining P2G with G2G can yield further cost savings since P2G improves the electricity system flexibility.

2) The G2G processes can significantly reduce the need for electricity generation capacity, and the P2G can increase wind power capacity integration. G2G processes can also increase hydrogen-fuelled generation investment cost-effectively, providing sufficient flexibility for the whole system without emitting carbon emissions. Conversely, hydrogen-fuelled generation is relatively low in the P2G scenario due to the higher cost of producing hydrogen.

3) The hydrogen will also provide an alternative option to decarbonise the heat sector and be combined with electrified heating methods. The hybrid HP-HB can take up 73% market share in the OPT scenario under the 10 Mt carbon target.

4) The deployment of HFCVs is sensitive to the cost of hydrogen production, and the lower cost of hydrogen production is driving more deployment of HFCV.

5) The capital cost of wind power and natural gas prices are two key factors that affect P2G and G2G facilities' penetration, respectively. The competitiveness of the P2G facility is highly sensitive to the variation of wind power capital cost. The rise of natural gas prices has significantly reduced the production of G2G.

Finally, As a result, the work was published in a journal paper presented in [111].

9.1.4. A Long-term Multi-Regional, Multi-Energy Systems Planning Towards the Future Low-Carbon Energy System of Great Britain

Long-term investment decisions should also be guided by considering short-term details to reflect the impact of system operation on long-term capacity planning. In Chapter 7, a novel multi-year modelling framework for the whole system optimisation of long-term MES investment is used to answer RQ4 through several studies. The findings are summarised as follows:

1) The multi-year MES model embeds unit commitment constraints in the electricity sector and operational constraints for other energy sectors in the long-term system planning.

2) The spatial and temporal resolution has significant impacts on system expansion planning. Typical weeks at the hourly level are selected by the k-medoids method to represent each planning year to capture short-term operation details while preserving computation tractability.

3) The proposed model in Chapter 7 also considers the technical lifetime of technologies. In order to get closer to the real energy system and provide reliable policy recommendations, the proposed multi-year MES planning model integrates carbon emissions constraints for different periods, multi-regional interconnected energy systems, and hourly energy scheduling.

As a comprehensive and flexible modelling framework, this multi-year MES transition model is applied to a series of comprehensive case studies in Chapters 8 to address RQ4 further. Chapter 9 assesses the three transition pathways and existing carbon reduction policies, using GB as a case study. The studies demonstrate that:

1) The hybrid pathway is the most cost-effective decarbonisation pathway, while the hydrogen pathway is the most expensive than the other pathways. However, each decarbonisation pathway's cost is relatively similar, but given the uncertainties involved, the ranking may change when different assumptions apply.

2) Existing fossil fuel generation capacity is being eroded by the rapid growth of RES generation, particularly wind power, which most importantly can reduce the operating cost of the electricity sector.

3) The sectors integration and electrification accelerate the decarbonisation of the whole energy system. The electricity generation becomes the backbone of the whole

system, which leads to lower overall energy supply cost. Rapid decarbonisation of the electricity sector complements direct electrification of the heat and transport sectors, which can shrink overall carbon emissions.

4) Hybrid heating technology will become the dominant option for decarbonisation in the heating sector.

5) The choice of decarbonisation option in the transport sector is relatively straightforward and depends mainly on the vehicle's capital cost and efficiency. According to the assumption of this thesis, the EV will dominate the future transport market.

6) Based on the utilisation rate of biomass raw material set in this thesis, the bioenergy supply can provide a maximum of approximately 50 Mt/year negative carbon emissions to offset the carbon emissions from other energy sectors, with the potential to provide more negative carbon emissions if increasing the utilisation rate of biomass raw material and imported biomass. The integration of DAC can also achieve sustainable carbon reductions if the capital cost of DAC is cost-effective.

7) The additional flexibility can bring cost savings for the overall system to transition to the net-zero target. The energy system's flexibility from technologies such as energy storage and DSR can reduce the capacity requirement for low-carbon generation and DAC facility to achieve the carbon targets.

Finally, this work results in a journal paper that has been submitted to [112].

9.2. Future Work

Based on the modelling experience and findings, a range of potential research areas that can be further developed is summarised and discussed as follows:

9.2.1. Understanding the Role and Value of Energy Storage for a Low-Carbon Energy System

Continue reduction in the battery energy storage cost, and development of various energy storage technologies (e.g., phase-change material, liquid air, compressed air, underground hydrogen storage) may open the opportunity for the substantial deployment of such technologies in future. The case for energy storage is driven by the increased connection of variable renewable energy sources. Short (hours) to long-duration (months) energy storage may be needed to facilitate the optimal low-carbon energy system development and to ensure the system resilient against a prolonged period of low-renewable sources. Energy storage can also reduce the system integration cost of renewables and enables more renewables to be deployed instead of nuclear or CCS.

The developed MES models can be further enhanced to incorporate different energy storage technologies and analyse the role and value of energy storage technologies either individually or in its optimised portfolio. The study will provide insight into the portfolio (capacity, location) for different energy storage technologies recognising the competition and the synergy across those technologies and other flexibility options. The future study can also investigate the business drivers for the various storage technologies, the system services that can be provided, and the commercial frameworks needed to remunerate the system benefits.

9.2.2. Investigating the Impact of Uncertainty on Future Energy System Planning and Operation

It is worth mentioning that all the results in this thesis are system-specific and depend on the given assumptions. The results are susceptible to the involved uncertainties such as technical data of each technology and future demand. In order to identify robust strategies for decarbonising various energy sectors, it is essential to investigate the impact of multiple sources of uncertainty on future energy system planning and operation.

Future work will address these limitations by considering the various uncertainties that arise across the system, determining robust solutions (e.g., least-regret approach), and understanding the impact of considerable uncertainty during the transition to a low-carbon future.

9.2.3. Scenarios Selection Approach for Reducing Computational Complexity in Future Energy System Planning

While taking into account a large number of operating conditions, the complexity of the investment planning model leads directly to a dramatic increase in computational burdens, especially in the long-term planning model. In Chapter 8, the k-medoids method is adopted to select representative weeks based on the input data (i.e., energy demand and RES profile).

To address the curse of dimensionality of large-scale systems, a cost-oriented representative day selection method that includes four main stages: clustering domain transformation, dimensionality reduction, cluster assignment, and representative day selection is adopted in [113], and the superior performance of the proposed method is demonstrated based on a GB electricity system. The tested generation investment planning problems with different complexity levels are designed to illustrate the increasing advantages of the proposed method over the conventional input-based method. The future work will apply the method to MES planning problems to demonstrate the effectiveness of this method on MES planning problems.

9.2.4. An Analysis of Cross-Energy Sector Flexibility for Future Energy System

In order to achieve the UK's decarbonisation targets in different periods, the UK's energy system will meet a variety of challenging investment decisions. Previous analysis in this thesis has highlighted that significant additional investment will be required across the system without planning for alternative providers of flexibility in the different transition pathways.

However, understanding flexibility in a market economy service system is a complicated task. There are many significant uncertainties, including projections of future energy systems, a large number of potential technology options, cost projections and so on. Given the wide variation in solutions for providing flexibility, it is vital to understand better flexibility across energy sectors, the scale of provision, and the costs and benefits associated with different transition pathways. Future work will investigate flexibility across different energy sectors and optimise the deployment of flexibility technologies.

9.2.5. A Comparison of Single-Year and Multi-Year Modelling Frameworks for Future Energy System Planning

In this thesis, the single-year and multi-year modelling frameworks are proposed to address future energy system planning problems. The single-year model framework aims to provide the optimal MES that meet the target for a specific future year without being limited by previous years' investments decisions. In contrast, the multi-year modelling framework casts over one or more decades, attempting to encapsulate the system's structural evolution and are used to investigate capacity expansion of energy system and transition issues.

Both models seek to solve the same problem but with different emphases, which raises a range of questions about the differences between the results (e.g., investment decisions and operation schedule) over the same period obtained by the two models subject to the same assumptions. The study will provide some insight into the impact of decisions taken during the transition period to 2050. Future work will compare these two models to address this open question.

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Appendix A. Key Assumptions and Input Data

In this appendix, the key assumptions that introduce the technologies adopted in each study and input data for all the energy sectors used in this thesis are given. All the cost data is provided for 2020, and these costs can be multiplied by the cost learning factors to give estimates of future costs. Lifetime represents both the technical lifetime over which the conversion technology operates and the economic lifetime over which the initial capital expenditure is paid off.

A.1. Key Assumptions

Table. A.1. Technologies adopted in each study.

		Chapter 4	Chapter 5	Chapter 6	Chapter 8
Electricity sector	Nuclear	✓	✓	✓	✓
	Gas-CCS	✓	✓	✓	✓
	H2-CCGT	✓	✓	✓	✓
	H2-OCGT	✓	✓	✓	✓
	H2-CHP	×	×	×	✓
	BECCS	×	×	×	✓
	BECHPCCS	×	×	×	✓
	CCGT	✓	✓	✓	✓
	OCGT	✓	✓	✓	✓
	Wind	✓	✓	✓	✓
	Farm PV	✓	✓	✓	✓
	Rooftop PV	✓	✓	✓	✓
	BES	×	×	×	✓
	DES	×	×	×	✓
Heat sector	Industrial HP	×	×	✓	✓

	Industrial NGB	×	×	✓	✓
	Industrial HB	×	×	✓	✓
	End-use HP	×	×	✓	✓
	End-use NGB	×	×	✓	✓
	End-use HB	×	×	✓	✓
Transport sector	FV	×	×	×	✓
	EV	✓	✓	✓	✓
	HFCV	✓	✓	✓	✓
Hydrogen sector	EL	✓	✓	✓	✓
	SMR CCS	✓	×	×	×
	ATR CCS	✓	×	×	×
	GHR CCS	×	×	✓	×
	GHR-ATR CCS	×	×	×	✓
	BHCCS	×	×	×	✓
	H2S	✓	✓	✓	✓
NETs	Biomass supply chain	×	×	×	✓
	DAC	×	×	×	✓

A.2. Parameters in the Electricity Sector

Table. A.2. Capital cost parameters of generation units [19, 114].

Generation	Capital cost (£bn/GW)	Fixed O&M (£/kW/year)	Discount rate (%)	Lifetime (year)
Nuclear	5.19	67.80	8.62%	50
Gas-CCS	2.15	41.60	6.02%	25

H2-CCGT	0.60	14.00	6.19%	25
H2-OCGT	0.40	5.30	5.87%	25
H2-CHP	0.91	30.60	6.19%	25
BECCS	2.72	41.60	8.62%	25
BECHPCCS	2.44	30.60	8.62%	25
CCGT	0.51	12.75	6.19%	25
OCGT	0.32	4.82	5.87%	25
Wind	2.42	95.83	5.64%	25
Farm PV	0.67	6.70	4.46%	35
Rooftop PV	0.72	7.60	4.46	30

Table. A.3. Operating cost and carbon emission parameters of generation units [19].

Generation	Fuel cost (£/MWh)	Start-up cost (£)	No-load cost (£/h)	Efficiency (%)	Carbon emission (g/kWh)
Nuclear	4.72	56710.00	108.90	35.00%	N/A
Gas-CCS	32.21	28075.90	1062.30	51.30%	36.06
H2-CCGT	N/A	21250.00	N/A	58.80%	0
H2-OCGT	N/A	19000.00	N/A	35.00%	0
H2-CHP	N/A	21250.00	N/A	36.00%	0
BECCS	N/A	21250.00	N/A	30.80%-36.80%	N/A
BECHPCCS	N/A	21250.00	N/A	36.00%	N/A
CCGT	27.39	28076.00	935.40	58.80%	314.63
OCGT	33.90	24461.00	7151.00	35.00%	528.57

Table. A.4. Operation parameters of generation units [19].

Generation	Minimum stable generation	Ramping rates	Maximum response provision	Maximum reserve provision
Nuclear	80%	10%	0%	0%
Gas-CCS	50%	50%	10%	50%
H2-CCGT	50%	60%	10%	50%
H2-OCGT	40%	100%	10%	60%
H2-CHP	50%	60%	10%	50%
BECCS	50%	50%	10%	50%
BECHPCCS	50%	60%	10%	50%
CCGT	50%	60%	10%	50%
OCGT	40%	100%	10%	60%
Wind	N/A	N/A	0%	0%
Farm PV	N/A	N/A	0%	0%
Rooftop PV	N/A	N/A	0%	0%

Table. A.5. Cost learning factor of generation units [114].

Generation	2025	2030	2035	2040	2045	2050
Nuclear	0.99	0.98	0.97	0.96	0.96	0.95
Gas-CCS	0.96	0.92	0.89	0.86	0.83	0.80
H2-CCGT	0.99	0.97	0.95	0.93	0.92	0.90
H2-OCGT	0.99	0.97	0.95	0.93	0.92	0.90
H2-CHP	0.95	0.90	0.88	0.85	0.84	0.82
BECCS	0.96	0.92	0.89	0.86	0.83	0.80
BECHPCCS	0.95	0.90	0.88	0.85	0.84	0.82

CCGT	0.99	0.97	0.95	0.93	0.92	0.90
OCGT	0.99	0.97	0.95	0.93	0.92	0.90

Table. A.6. Capital cost parameters of electricity transmission lines [100].

Transmission lines	Capital cost (£/MW/km)	Discount rate (%)	Lifetime (year)
Onshore transmission lines	1500	2.8%	40
Subsea transmission lines	1954	2.8%	40

Table. A.7. Capital cost parameters of EES [101].

	Capital cost (£/kW)	Duration (hour)	Fixed O&M (£/kWh/year)	Discount rate (%)	Lifetime (year)
BES	56.2	6	6.1	3.5%	40
DES	96.2	3	4.3	3.5%	15

A.3. Parameters in the Heat Sector

Table. A.8. Capital cost parameters of industrial heating technologies [100].

Heating technologies	Capital cost (£/kW)	Fixed O&M (£/kW/year)	Discount rate (%)	Lifetime (year)
Industrial HP	480	3.20	3.5%	10
Industrial NGB	80	2.96	3.5%	10
Industrial HB	80	2.96	3.5%	10

Table. A.9. Capital cost parameters of end-use heating technologies [100].

Heating technologies	Capital cost (£/unit)	Fixed O&M (£/unit/year)	Size (kW)	Installation cost (£/unit)	Discount rate (%)	Lifetime (year)

End-use HP	6000	220	10	1200	3.5%	10
End-use NGB	1500	120	20	1000	3.5%	10
End-use HB	1500	120	20	1000	3.5%	10

Table. A.10. Operation parameters of heating technologies [19, 100].

Heating technologies	Efficiency (%)	Carbon emission (g/kWh)
Industrial HP	380%	N/A
Industrial NGB	98%	188.78
Industrial HB	98%	N/A
End-use HP	160%-360%	N/A
End-use NGB	95%	194.74
End-use HB	95%	N/A

Table. A.11. Cost learning factor of heating technologies [114].

Heating technologies	2025	2030	2035	2040	2045	2050
Industrial HP	1.00	1.00	1.00	1.00	1.00	1.00
Industrial NGB	0.97	0.94	0.91	0.88	0.86	0.83
Industrial HB	0.97	0.94	0.91	0.88	0.86	0.83
End-use HP	0.95	0.90	0.83	0.75	0.68	0.60
End-use NGB	0.95	0.90	0.83	0.75	0.68	0.60
End-use HB	0.95	0.90	0.83	0.75	0.68	0.60

Table. A.12. Capital cost parameters of district heating networks [115].

Type of regions	Capital cost of heat	Capital cost of internal	Capital cost of heat	Capital cost of hydraulic interface	Discount rate (%)	Lifetime (year)

	network (£/MWh)	pipelines (£/MWh)	meters (£/MWh)	units (£/MWh)		
Urban	263	492	170	253	2.8%	40
Suburban	404	492	170	253	2.8%	40
Rural	1094	492	170	253	2.8%	40

A.4. Parameters in the Transport Sector

Table. A.13. Capital cost (£/unit) parameters of vehicles [116].

Type of vehicles	2020	2025	2030	2035	2040	2045	2050	Discount rate (%)	Lifetime (year)
FV	15630	15884	16138	16316	16493	16595	16697	3.5%	10
EV	22595	20412	18228	17998	17768	17582	17395	3.5%	10
HFCV	43260	33002	22744	21528	20311	20003	19695	3.5%	10

Table. A.14. Fuel consumption (kWh/km) of vehicles [116].

Type of vehicles	2020	2025	2030	2035	2040	2045	2050
FV	0.53	0.49	0.44	0.42	0.39	0.38	0.36
EV	0.17	0.17	0.17	0.15	0.14	0.14	0.14
HFCV	0.25	0.24	0.22	0.22	0.22	0.21	0.19

Table. A.15. Carbon emission (gCO2/km) of vehicles [116].

Type of vehicles	2020	2025	2030	2035	2040	2045	2050
FV	129.80	118.35	106.90	101.10	95.30	91.40	87.50
EV	0	0	0	0	0	0	0
HFCV	0	0	0	0	0	0	0

A.5. Parameters of Hydrogen Integration

Table. A.16. Capital cost parameters of hydrogen production technologies [36, 117].

Hydrogen production	Capital cost (£/kW)	Fixed O&M (£/kW/year)	Discount rate (%)	Lifetime (year)
EL	600	48.5	8.62%	30
GHR-ATR	554	24.4	8.62%	40
BHCCS	4902	N/A	8.62%	30

Table. A.17. Operation parameters of hydrogen production [36, 117].

Hydrogen production	Efficiency (%)	Carbon emission (g/kWh)
EL	74%	8.4
GHR-ATR	89%	24.4
BHCCS	40%	N/A

Table. A.18. Cost learning factor of hydrogen production technologies [30, 114].

Hydrogen production	2025	2030	2035	2040	2045	2050
EL	0.88	0.81	0.79	0.78	0.77	0.76
GHR-ATR	0.91	0.87	0.80	0.75	0.70	0.66
BHCCS	0.84	0.67	0.67	0.67	0.67	0.67

Table. A.19. Capital cost parameters of hydrogen transmission pipelines [100].

Transmission pipelines	Capital cost (£/MW/km)	Discount rate (%)	Lifetime (year)
H_2 transmission pipelines	265	2.8%	40

Table. A.20. Capital cost parameters of H2S [100].

	Capital cost (£/kW)	Duration (hour)	Fixed O&M (£/kWh/year)	Discount rate (%)	Lifetime (year)
H2S	3.3	6	0.34	3.5%	40

A.6. Parameters of NETs Integration

Table. A.21. Annual biomass raw material availability (Mt/year) for 2020-2030 [37].

Biomass raw material	SCOT	EW-N	EW-M	EW-S	LON
Miscanthus	20.38	15.44	23.24	18.78	5.35
Poplar	22.41	15.44	23.24	18.78	5.35
Waste wood	0.10	0.12	0.34	0.22	0.24
MSW	0.99	1.11	3.20	2.02	2.21
Crop residue	1.09	1.13	0.66	2.49	1.38
Forest residue	0.15	0.05	0.08	0.03	0.00

Table. A.22. Annual biomass raw material availability (Mt/year) for 2030-2040 [37].

Biomass raw material	SCOT	EW-N	EW-M	EW-S	LON
Miscanthus	20.70	16.03	24.57	19.30	3.44
Poplar	22.06	15.00	23.21	18.46	5.27
Waste wood	0.11	0.08	0.40	0.23	0.25
MSW	1.04	0.76	3.76	2.12	2.32
Crop residue	1.09	0.96	0.83	2.49	1.38
Forest residue	0.15	0.05	0.08	0.03	0.00

Table. A.23. Annual biomass raw material availability (Mt/year) for 2040-2050 [37].

Biomass raw material	SCOT	EW-N	EW-M	EW-S	LON
Miscanthus	21.02	16.26	24.96	19.60	3.50
Poplar	21.74	14.78	22.86	18.18	5.18
Waste wood	0.11	0.08	0.42	0.24	0.26
MSW	1.09	0.79	3.93	2.22	2.42
Crop residue	1.09	0.96	0.83	2.49	1.38
Forest residue	0.15	0.05	0.08	0.03	0.00

Table. A.24. Parameters of biomass raw material [37].

Biomass raw material	Unit supply cost (£/t)	Pellet conversion rate (%)
Miscanthus	21.02	16.26
Poplar	21.74	14.78
Waste wood	0.11	0.08
MSW	1.09	0.79
Crop residue	1.09	0.96
Forest residue	0.15	0.05

Table. A.25. Parameters of biomass pellets [37].

Biomass raw pellets	Energy density (GJ/t)	Carbon content (%)	Pellet operation cost (£/t)
Miscanthus pellets	18.41	44.10%	17.86
Poplar pellets	18.50	43.69%	26.70
Waste wood pellets	18.70	40.00%	17.55
MSW pellets	12.50	35.46%	18.14

Crop residue pellets	18.70	44.10%	18.14
Forest residue pellets	15.12	40.00%	18.14

Table. A.26. Economic and operational parameters of DAC technology [39].

	2020	2025	2030	2035	2040	2045	2050
Capital cost (£/tCO_2/year)	734	537	340	289	239	219	200
Operation cost (%/capital cost)	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
Electricity demand (kWh/tCO_2)	1535	1535	1458	1458	1385	1385	1316