Multi-scale modelling of integrated energy supply systems

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Abstract

Local energy systems are changing with the use of more distributed generation as well as the decarbonisation of heat and transport, but the impacts of these local changes on national scale energy supply systems are not well understood. The existing whole energy system models lack the spatial granularity to represent local energy systems and their interactions with gas and electricity transmission networks. This key limitation was addressed by the new CGEN+Energy Hubs model.

The CGEN+Energy Hubs Model enables multi-time period operational analysis of integrated national and local energy supply systems. The CGEN+Energy Hubs model was developed by extending a well-established Combined Gas and Electricity Network model (CGEN) by adding the representation of local energy systems. Energy Hubs were used to represent local energy systems in different geographic areas of GB. The CGEN+Energy Hubs model also extended CGEN by including functions for bi-directional electricity interconnector flows, intermittent renewable generation, demand response, distributed injection of hydrogen and biogas, and vehicle to grid electricity supply.

The application of the CGEN+Energy Hubs model was demonstrated using contrasting Energy Supply Strategies. The Energy Supply Strategies were defined to explore options to decarbonise heat supply in GB: i.e. 1) low-carbon electricity in the Electric Strategy 2) biomass and solid-waste fuelled CHP in the Heat Network Strategy, 3) hydrogen and biogas in the Green Gas Strategy, and 4) Unconstrained, which employs cost optimisation to choose the heating technology.

The Energy Supply Strategies were first applied to the Oxford-Cambridge Arc region to investigate how each strategy would cost-effectively reduce CO_2 emissions from the Arc's energy system. The Electric Strategy was shown to be able to meet the CO_2 emissions target in 2050 at the lowest annualised costs per dwelling (investment and operation). The study showed that additional investment is needed to increase the capacity of transmission electricity supply, distributed generation, and the electricity distribution network.

The Energy Supply Strategies were then applied to all Energy Hubs in GB simultaneously. The Electric Strategy was again shown to be able to deliver the net-zero CO_2 emissions target in GB at the lowest annual operating costs. It was shown that CCGT generator capacity is required to mitigate the impact on the electricity transmission network due to the variability of renewable generation. Battery storage systems are proposed to replace CCGT plants and further reduce the use of natural gas.

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Nomenclature

Abbreviations and Acronyms

BECCS	Bioenergy with Carbon Capture and Storage
BEIS	Department for Business Energy and Industrial Strategy
CCS	Carbon Capture and Storage
CGEN	Combined Gas and Electricity Network model
EV	Electric Vehicles
GCV	Gross Calorific Value
GDP	Gross Domestic Product
GHG	Green House Gases
HGV	Heavy Goods Vehicles
HPR	Heat to power ratio of a CHP unit
LAD	Local Authority District
LNG	Liquified Natural Gas
NISMOD	National Infrastructure Systems Model
SMR	Steam Methane Reformation
UKCS	United Kingdom Continental Shelf

Constants

R	Gas constant (518 J/kg.K)
Z	Gas compressibility factor

Subscripts

a	Gas terminal
b	Electricity busbar
c	Compressor
d	Demand
e	Electrical energy
g	Natural gas energy
h	Heat energy
h_2	Hydrogen energy

k	Electricity generation plant
l	Electricity transmission line
n	Gas node
ps	Pumped hydropower station
m	Gas pipe
t	Time
u	Gas storage facility
τc	Compressors run by natural gas-fired prime movers
s	Sector (residential, commercial, or industrial)
bio	Bioenergy
w	Energy from waste

Superscripts

av	Average value
eh	Supply/consumption connected to an Energy Hub
exp	Export electricity via interconnector
$G2V$	Grid to vehicle
i	Gas Injection
imp	Import electricity/gas via interconnector
ind	Industrial processes
max	Maximum value possible
min	Minimum value possible
n	The standard conditions
$powerGen$	Power generation
res	Natural gas resource
sp	Spot price
$store$	Stored energy level
$tran_K$	Transmission to Energy Hub K
$tran$	Supply/consumption connected to a transmission network
ue	Unserved electricity demand
ug	Unserved gas demand
$V2G$	Vehicle to grid
w	Gas withdrawal

Parameters

h	Height
A	Area
C	Cost (£)

D	Diameter
Ef	Emissions factor for CO_2 equivalent
H	Heat value at normal conditions
I	Irradiance
L	Length
M	Matrix
MDT	Minimum downtime of a thermal power station (h)
MUT	Minimum uptime of a thermal power station (h)
PR	Performance ratio of a PV panel
RD	Maximum power ramp down (MW/h)
RU	Maximum power ramp-up (MW/h)
T	Temperature
f	The friction factor of a pipe
$r\omega$	Percentage of wind and PV generation contributing to up spinning reserve requirements
t	Timestep (h)
v	Wind speed
α	Polytropic exponent (1.27)
β	Gas turbine linear fuel coefficient of a compressor (0.084 m3/MJ)
η	Efficiency
ρ	Density, assuming standard conditions.

Variables

B	Biomass (kg)
E	Energy (MWh)
Em	Equivalent CO_2 emissions
LP	Gas linepack (mcm)
P	Power flow (MW)
Q	Gas flow (mcm)
S	Gas storage level (mcm)
V	The volume of a pipe (m3)
W	Municipal solid waste mass (kg)
p	pressure (bar)
r	Spinning reserve (MW)
γ	On/Off state of a thermal electric power station (1/0)
τ	Amount of gas trapped by a compressor (mcm)
∂LP	Change in gas linepack (mcm)

1. Introduction

1.1. Background

In the UK, electricity and natural gas supply systems are traditionally planned and operated independently of each other. Electricity is mainly generated from large, centralised power stations using fossil fuels and natural gas is supplied via reception terminals as imports (LNG and Norwegian supplies) and from North Sea gas fields (UKCS). Electricity and natural gas from these centralised sources are transported via networks to residential, commercial, and industrial consumers.

Fossil fuels such as oil, natural gas, and coal dominated primary energy supplies in 2017 accounting for a total of ~1200TWh (BEIS, 2018a). Fossil fuels are mainly used for industrial applications, electricity generation, transportation, and heating. Fossil fuels consumed across these sectors in the UK accounted for annual emissions of 503MtCO_2e in 2017 (National Grid, 2019a).

In 2019, the UK government set an ambitious target to reduce all greenhouse gas emissions to "net-zero" by 2050, surpassing the previous target to reduce emissions below 80% from 1990 levels (CCC, 2019a). Therefore, significant changes are required to decarbonise both the end-use and supply of energy. The National Grid and Committee on Climate Change (CCC, 2019b; National Grid, 2019a) have identified a number of ways in which net-zero emissions can be achieved. These are discussed in detail in Chapter 2, and can be summarised as:

- The use of fossil fuels for heating and industrial applications are replaced by low-carbon electricity, hydrogen, and bioenergy.
- Electric and hydrogen fuel cell vehicles are used for road transport instead of vehicles with internal combustion engines.
- Low-carbon electricity is generated from onshore/offshore wind farms, and nuclear power stations.
- Decentralised low-carbon electricity generation from onshore wind and solar PV, and the use of battery storage systems to store excess renewable electricity is needed.
- Decentralised production of biomethane and BioSNG to replace natural gas is anticipated.
- Hydrogen is produced by electrolysis using excess electricity from renewables and using natural gas in Steam Methane Reforming (SMR) equipped with carbon capture and storage.

These developments will create a rapid transition of energy supply systems from mainly centralised and carbon-intensive systems towards decentralised and decarbonised systems. This would require the planning and operation of new infrastructure systems (BEIS, 2019a; NIC, 2018a). For example, carbon capture, transportation and storage infrastructure are essential to decarbonise industry and hydrogen production using natural gas. Dedicated hydrogen transportation networks will be needed to supply hydrogen for heating, transport, and industrial processes.

1.2. Interdependencies in energy supply systems

Interdependencies in energy supply systems are typically established by using energy conversion technologies (Mancarella, 2014a). For example, natural gas used for electricity generation creates an interdependency between natural gas and electricity supply systems. Depending on the connection of the energy conversion technology, the interdependency occurs at the national (connected to transmission networks) or local level (connected to distribution networks).

At the national level, the electricity and natural gas transmission networks are coupled with large gas-fired generators (CCGT/OCGT) (Qadrdan, 2012a). This existing interdependency by the use of natural gas for electricity generation will reduce as total electricity generated by large gas-fired generators is projected to reduce in the coming years (National Grid, 2019a). However, there will be new interdependencies given the transition towards producing hydrogen at a large scale using steam methane reformation and electrolysis. The use of a separate hydrogen transmission network is being considered (CCC, 2018a), which once implemented would couple electricity, natural gas and hydrogen transmission networks via hydrogen production facilities.

Figure 1.1 shows the interdependencies between different local energy supply systems. The interdependencies in a local energy system are much more complicated compared to the interdependencies of national gas and electricity transmission systems. The existing interdependencies between natural gas and heating will reduce as the use of natural gas is replaced by low-carbon alternatives (BEIS, 2019b). Consequently, new interdependencies are emerging between electricity, hydrogen, bioenergy, and heating systems.

These interdependencies in energy supply systems are of emerging importance in the energy system design, planning and operation under future scenarios such as the decarbonisation of heat and transport (CCC, 2018b; UKERC, 2019a; Watson et al., 2017).

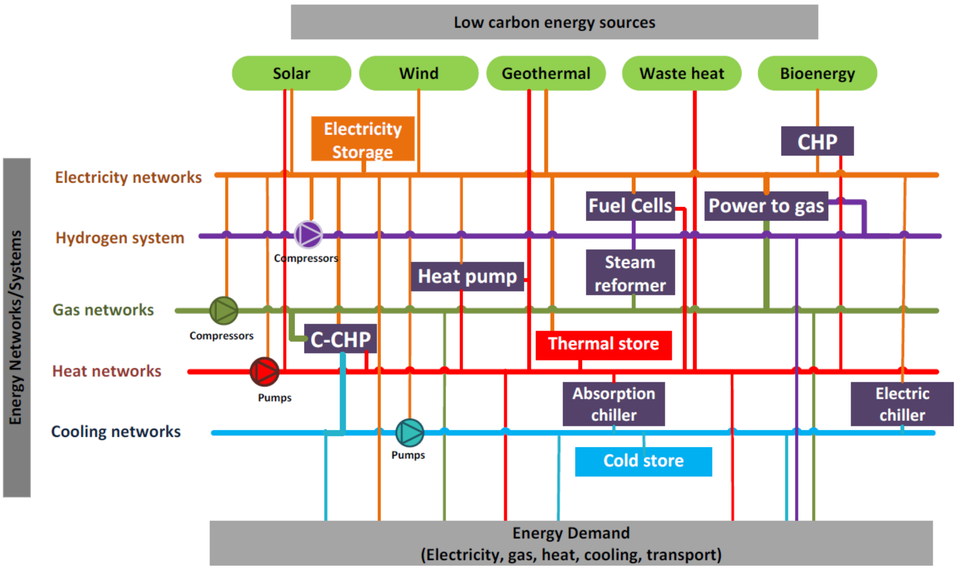

Figure 1.1 – Interdependencies between different local energy supply systems (Abeysekera, 2016)

1.3. Opportunities and challenges in integrated energy systems

There are several benefits but also challenges of integrating energy systems. There are multiple supply paths in an integrated energy system which provide an opportunity to optimise the operation of the energy system with combined objectives to reduce carbon emissions at the lowest operating costs (Liu and Mancarella, 2016). Several studies (Cesena and Mancarella, 2016; Mancarella and Chicco, 2013a) have shown that integrated energy systems can provide flexibility to the electricity system. There is a potential to increase the generation and utilisation of renewable electricity by integrating the electricity network with other energy supply systems (e.g. hydrogen production and supply) (Niemi et al., 2012). Further benefits of integrated energy systems are discussed in (Abeysekera, 2016; Mittal et al., 2015; Rees, 2012).

Integrated local energy systems have been identified to play a key role in meeting the net zero emissions target by utilising low-carbon energy supply resources, technologies and storage systems (UKERC, 2019a). However, the optimal mix of technologies and resources is likely to be different from one local energy system to another. Given the complexity of interdependencies within local energy systems, the system operator needs detailed insights on how these local interdependencies would impact the operation of national gas and electricity networks.

Existing studies of energy systems often investigate national or local integrated energy systems separately. In addition, most of the existing whole energy system modelling tools are single node and lack spatial and temporal detail to represent integrated local energy systems. The computation requirements are of concern in modelling both national and local integrated energy systems. The research presented in this thesis contributes to bridging the gap by studying integrated national and local energy systems.

1.4. Research Objectives

The main objectives of this thesis are,

a) To present the rationale and development of an integrated modelling tool with the ability to represent dispersed local energy systems in a national gas and electricity network model
b) To demonstrate how such a tool can provide insights regarding the impacts of local energy supply strategies on the operation of GB gas and electricity networks.

A new integrated modelling tool, the CGEN+Energy Hubs Model provides a multi-time period operational analysis of integrated national and local energy supply systems in GB. The CGEN+Energy Hubs Model builds on a well-established Combined Gas and Electricity Network model (CGEN) (Chaudry et al., 2008). The established CGEN model was extended by integrating local energy systems represented as the Energy Hubs.

The Energy Hub concept (Geidl, 2007) essentially captures the interdependencies between local electricity, natural gas, heat and hydrogen supply systems through energy conversion technologies but does not model detailed distribution networks. Consequently, the use of Energy Hubs reduces the computational requirement compared to using a local energy system model with detailed distribution network representations. This also allowed the modelling of additional aspects of the Energy Hubs: i.e. demand-side response, distributed injection of hydrogen and biogas, and vehicle to grid electricity supply.

During the model development process, improvements were made to the established CGEN model. Renewable electricity generation modelling was improved to take into account spatial variability, and climate change impacts on wind speeds and solar irradiance. The modelling of electricity interconnectors was improved to consider bi-directional power flows. Also, the characterisation of different natural gas supply resources (UKCS, LNG, interconnector imports and shale gas) were added.

To demonstrate the application of the CGEN+Energy Hubs model four contrasting Energy Supply Strategies were defined: i.e 1) Electric, 2) Heat Networks, 3) Green Gas and 4) Unconstrained. These Energy Supply Strategies are based on options to decarbonise heating in GB. Additional assumptions were included for the use of low-carbon electricity and hydrogen in industry and transport. An initial assessment was made on the use of Energy Hubs to model local energy systems and the efficacy of Energy Supply Strategies to cost-effectively reduce CO_2 emissions from the Oxford-Cambridge Arc region was investigated. Furthermore, the impact on national gas and electricity networks were investigated by simultaneously applying the Energy Supply Strategies to all the Energy Hubs in GB.

1.5. Thesis Outline

Figure 1.2 outlines the thesis and the description of the work carried out are summarised below.

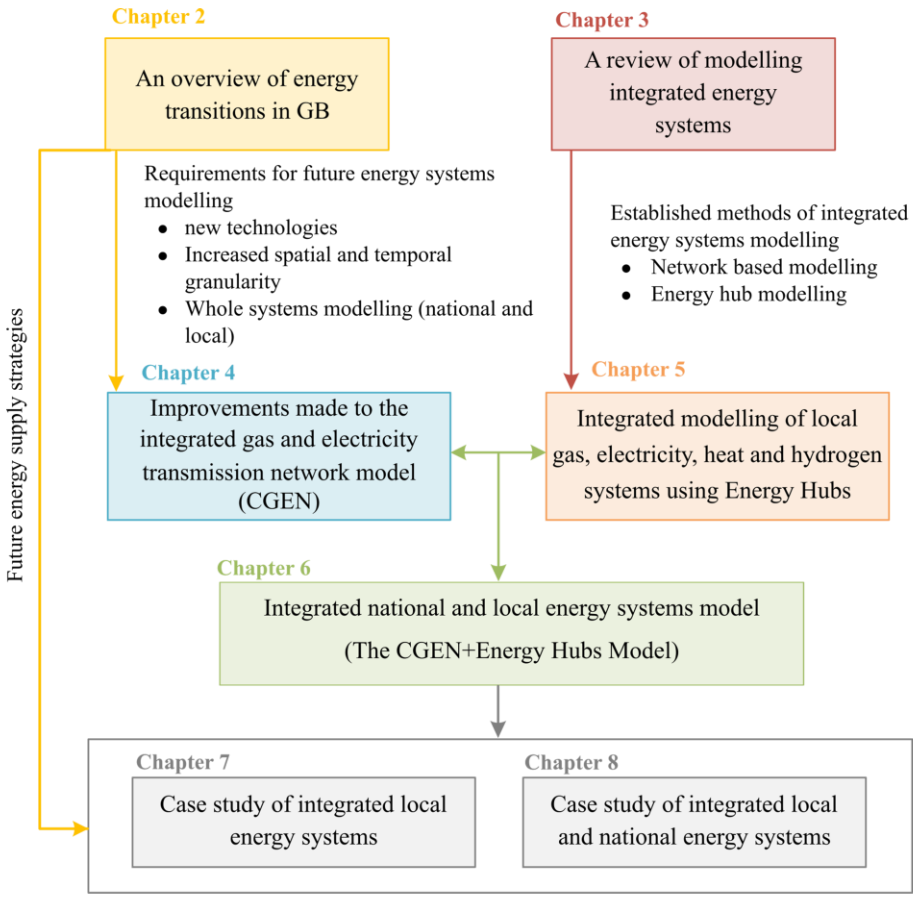

Figure 1.2 – Outline of the thesis

After the Introduction, Chapter 2 is an overview of the transition in the GB energy system towards decarbonising end energy use and the supply of energy.

Steady-state modelling, simulation and optimisation methods for integrated energy systems were reviewed in Chapter 3. The review was extended to existing modelling tools and to identify their limitations and the research gaps.

Chapter 4 describes the developments made to the established CGEN model. Improvements were made to the spatial representation of the gas and electricity transmission networks in the established CGEN model to integrate local energy systems. In addition, improvements were made to model bi-directional electricity interconnectors, intermittent renewable generation, and characterisation of natural gas supply resources.

In Chapter 5, an Energy Hub model was developed to provide an aggregated view of energy supply and demand within a local energy system. Interdependencies between electricity, natural gas, heat, and hydrogen supply systems were modelled. In addition, energy demand for transport, demand-side management, intermittent renewable generation, vehicle to grid electricity supply and distributed injection of green gases were modelled into the Energy Hub.

The CGEN+Energy Hubs Model was developed in Chapter 6. Energy Hubs were used to model local energy systems across GB and were integrated with the natural gas and electricity transmission networks. The CGEN+Energy Hubs model was integrated with a National Infrastructure Systems Model (NISMOD) to model interdependencies with energy, water supply and transport systems.

In Chapter 7, a case study was performed to assess how different local Energy Supply Strategies could affordably reduce CO_2 emissions within the Oxford-Cambridge Arc region. Four contrasting Energy Supply Strategies were defined: i.e. 1) Electric, 2) Heat Networks, 3) Green Gas and 4) Unconstrained, based on options for heat supply using low-carbon electricity, heat network solutions green-gases (hydrogen and biogas) and cost optimisation techniques. Case study results for the Oxford-Cambridge Arc region were used to demonstrate the use of Energy Hubs to study local energy systems that are subjected to heat decarbonisation.

In Chapter 8, the CGEN+Energy Hubs Model was used to investigate the impacts of local Energy Supply Strategies on gas and electricity transmission networks. The Energy Supply Strategies defined in Chapter 7 were modified to move from 80% reduction to net-zero in CO_2 emission target. The modifications replaced the use of fossil fuels for heating, industry and transportation with low-carbon electricity and hydrogen. The modified Energy Supply Strategies were applied simultaneously to all Energy Hubs in GB. The results demonstrate the modelling of dispersed local energy systems to provide insights regarding the impacts of local Energy Supply Strategies on the operation of gas and electricity transmission networks.

2. An overview of energy transitions in GB

2.1. Introduction

The GB energy system is transforming into a decarbonised and decentralised energy system. Rapid changes are underway in how energy is managed across electricity, gas and heat supply systems. The GB electricity system has operated as a traditional centralised system where electricity is generated from large-scale, carbon-intensive assets such as natural gas and coal-fired generation plants. The natural gas system has been utilised mainly for heat supply via gas boilers in residential and commercial buildings, and in gas-fired power generation plants which respond to the variations in electricity supply and demand. Transitions are taking place that results in a more complex and dynamic system based on decentralised, low-carbon energy sources, flexible grid infrastructure and greater connectivity between energy markets. An overview of these energy transitions, limitations and challenges are presented.

2.2. Climate change mitigation targets

In 2015, the Paris Agreement was signed by 196 States within the United Nations Framework Convention on Climate Change (UNFCC, 2015). The long-term objective of the agreement is to keep the increase in global average temperature well below 2°C and limit the increase to 1.5°C. Under the agreement, each country must determine and regularly report on their contribution to mitigating all greenhouse gas (GHG) emissions.

The UK government adopted the Climate Change act in 2010 (Parliament of the United Kingdom, 2008), to set targets for the reduction of greenhouse gas emissions by 80% of 1990 levels by the year 2050. However, in 2019, a more ambitious target was set in law to further reduce greenhouse gas emissions to “net-zero” by 2050 (CCC, 2019a). Hence, significant measures are demanded across different sectors by 2050 as outlined in Table 2.1.

Table 2.1 – Measures required to meet the ambitious "net-zero" emission target (CCC, 2019a) *compared with the previous target*

Sector	Measure	Current uptake (2017)	Uptake required in 2050	
			Prev. Target: 80% reduction in GHG emissions	New Target: "Net-Zero" GHG emissions
Power	Share of low-carbon generation	50%	97%	100%
	Low- carbon generation (TWh)	155	540	645
Building	Share of low carbon heat supply residential buildings	4.5%	80%	90%
	Share of low carbon heat supply non-residential buildings		100%	100%
Industry	Carbon Capture and Storage	0%	50%	100%
	Share of low-carbon heat supply	<5%	10%	85%
Surface Transport (Share of the fleet)	Battery electric cars and vans	0.2%	80%	100%
	Electric and hydrogen HGVs	0%	13%	91%
Aviation	gCO_2 per passenger km	110	70	55
	Sustainable biofuel uptake	0%	5%	10%
Shipping	Ammonia uptake	0%	5%	10%
Land use and Forestry	Afforestation (% of UK land area)	13%	15%	17%
	Peatland restoration (% area in good condition)	25%	n/a	55%
Engineered CO_2 removal ($MtCO_2$)	Bioenergy and CCS	0	20	51
	Direct air capture (DACS)	0	n/a	1

2.3. An overview of the energy system transitions

Transitions due to the climate change mitigation targets have the focus to decarbonise both end-use and supply of energy. Significant transitions are expected in the heat supply and transport sectors, which are the leading contributors to the UK's annual emissions. These end-use changes are supported by the decarbonisation of the electricity and natural gas supply systems in combination with the use of bioenergy and hydrogen.

2.3.1. Low carbon heat supply

The heat supply is the single biggest contributor to UK emissions. In 2016, heat supply accounted for 37% (174 $MtCO_2e$) of total emissions from space heating, industrial processes, cooking and hot water (BEIS, 2018b). Approximately, 85% of domestic and 65% of non-domestic buildings, and 40% of the industry use natural gas as a fuel for heat. A substantial reduction in heat supply related emissions is needed to meet the "net-zero" emissions target.

Improved technological efficiency and thermal insulation in buildings will help to reduce the overall energy consumption for heating. The efficiency and insulation improvements mean that by 2050, homes could use up to 26% less energy for heating compared to today (National Grid, 2019a). This has been identified as urgent no regret actions that can remove barriers to deploying low carbon heating solutions at scale (UKERC, 2019a).

Low-carbon fuel and new technology options are available to decarbonise the heat supply in residential, commercial, and industrial sectors. Examples include the use of electricity from low-carbon sources to produce heat via heat pumps, the use of green gas mixtures in existing gas boilers and CHP units, and hydrogen-fuelled heating systems.

Previous studies have compared the economics of different technological options, such as heat pumps, hybrid heat pumps and district heating networks. The use of electric heating and installation of heat pumps with existing residential gas boilers as a hybrid system has shown economic advantageous over district heating networks (Zhang et al., 2018). However, electric heating technologies will significantly increase the electricity demand and will require expansion in electricity generation capacity and network reinforcements (Liu et al., 2016). The use of heat pump and gas boiler systems as a hybrid setup will help to reduce the need to expand electricity generation capacity which is only used on a few colder days each year (Chaudry et al., 2015).

District heating applications may play an important role in urban areas. As the natural gas network continues to decarbonise with biogas and hydrogen injection, there will be a reduction of carbon emission from CHP units and large gas boilers used in district heating applications. Waste heat from an industrial or a power generation plant has been shown to be a cost-effective and low-carbon option to be used in newly built district heating systems (Papapetrou et al., 2018). When the heat source of an existing heat network is switched to a low-temperature waste heat source, the heat pipe network size may be limited in delivering the hot water volume flow rates required to provide the same thermal energy to consumers as of using a high-temperature heat network (Millar et al., 2020).

Scenario studies discuss the use of hydrogen as a fuel in hybrid heat pumps, boilers and fuel cells for low carbon heat supply (Dodds et al., 2015). A large uptake in hydrogen-fuelled heating systems will increase hydrogen production at scale. The carbon savings in heat supply may be offset by the carbon emissions in large scale hydrogen production with methane reformation and coal gasification without carbon capture and storage (CCC, 2018a).

2.3.2. Energy use in transport

Petrol and diesel have been the main energy source for transportation. In 2016, emissions from the transport sector accounted for 27 % (126 $MtCO_2e$) of total UK emissions (BEIS, 2018b), of which over 90% was from road transport. A shift towards electrification and the use of alternative low carbon fuels (biofuels and hydrogen) in the transport sector is essential to meet the emission targets by 2050.

Reports (National Grid, 2019a) and (CCC, 2019a) envisage that carbon emissions from light road transport are nearly zero by 2050. There will be a rapid uptake in electric cars and vans beyond the 2020s. The National Infrastructure Commission (NIC) projects a need for 210,000 public charging stations to supply the transport electricity demand across motorways, depots, towns and cities (NIC, 2016). Over the coming years, the electrification of rail lines is expected to grow. Alternative low-carbon options such as the use of biofuels and hydrogen are being trialled (National Grid, 2019a).

The growing concerns on energy use in transport are related to electric vehicles (EVs) and their charging demand. Timing, location, and frequency of EV charging vary and depend entirely on consumer behaviour. The National Grid Community Renewables scenario projects that an unmanaged behaviour of EV charging would add 24GW to the electricity peak demand (Figure 2.1). The annual electricity demand for transportation is also expected to grow rapidly to 100TWh by 2050. Management of EV charging through consumer participation mechanisms such as smart charging, vehicle to grid (V2G) and vehicle to home[1] (V2H) can help reduce the increase in electricity peak demand.

There are technical limitations to use electricity in heavy goods vehicles. Therefore, there is a much slower progression in decarbonising heavy goods vehicles using electricity (DfT, 2018). An alternative is to use hydrogen in heavy goods vehicles, but this requires new refuelling infrastructure across motorways and depots. The National Grid projects that annual transport demand for hydrogen would grow up to 50TWh by 2050 (National Grid, 2019a).

[1] V2H – Vehicle to Home, utilising EV battery as an electric storage unit to balance the electricity demands within residential premises.

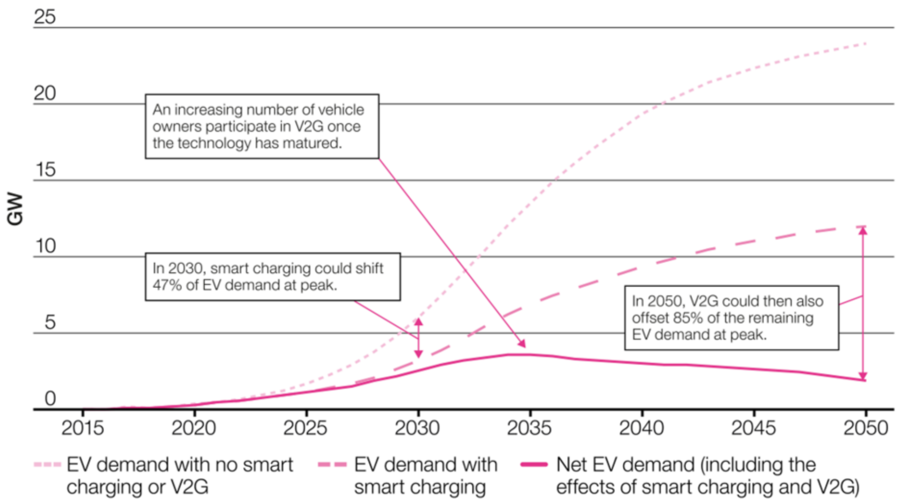

Figure 2.1 – Total EV charging demand at system peak (National Grid, 2019a)

2.3.3. Flexibility in electricity demand

Electricity demand flexibility is important to balance intermittent low-carbon generation with the increasing demand for transportation and heating. Flexibility is provided, for example in the residential sector by moving electricity demand for EV charging and washing machines to times when there is a plentiful supply of low-carbon electricity. This allows for greater growth of low-carbon electricity generation and reduces the amount of network infrastructure required to meet demands during the peak period (National Grid, 2019a).

Rollout of smart meters, smart appliances and battery storage systems are expected to facilitate demand flexibility. Approximately 30% of industrial and commercial consumers are already providing demand flexibility, and plans are underway to engage the reset of the consumers (Ofgem, 2016). In the residential sector, there is a growing interest to utilise the EV batteries for secondary purposes such as managing personal electricity demands via V2H; Vehicle to Home and even support the electricity grid for balancing purposes via V2G; Vehicle to Grid (Küfeoğlu et al., 2019). Clusters of consumers engage in demand flexibility via aggregators; organisations that coordinate consumers' flexibility (demand and generation) and offer services to where and when it is needed. Typical electricity demand patterns are therefore changing due to the active participation of consumers to shift their demand via smart technologies.

2.3.4. Large scale low-carbon electricity generation

Low carbon electricity generation from renewable energy sources (wind, solar irradiance, and tidal stream) are growing to replace carbon-intensive electricity generation. Offshore wind farms are projected to dominate future electricity generation by renewable sources due to the reductions in costs (turbine costs) and support from government incentives (National Grid, 2019a). However, intermittent electricity generation challenges the operation of conventional power systems leading to concerns regarding the security of supply.

Electricity generation plants with rapid ramp-up/down capabilities are required in the power system to compensate for the differences in electricity supply and/or demand, particularly with the variability of renewable electricity generation. Even though hydropower plants have a rapid ramping capability, in GB they are limited in capacity (DECC, 2014). The use of natural gas-fired power stations links the operation of natural gas and electricity transmission networks (Chaudry et al., 2008; Rubio Barros and Ojeda-Esteybar, 2008). Rapid ramping of these generators is likely to cause an increase in maintenance, lower capacity factors and lower operating efficiencies (Qadrdan et al., 2010a). As natural gas is being consumed to generate power, large swings in gas linepack are expected within the natural gas transmission network (Qadrdan, 2012b). Plans are underway to equip gas-fired generators with CCS in line with the low carbon electricity generation incentives. Decarbonisation of peak generation plants by using hydrogen is also proposed (CCC, 2019a).

The majority of the existing nuclear fleet is set to retire by 2030 and a new nuclear fleet of capacity up to 16GW is planned (National Grid, 2019a). The addition of large scale power stations requires reinforcement and expansions of the electricity transmission network (Qadrdan, 2012b).

The “net-zero” emission target requires the conversion of existing dedicated biofuel (biomass and biogas) power generation to be equipped with CCS. It is projected that by 2050, 43TWh of electricity is to be produced using 117TWh of bioresources, with an overall removal of 37MtCO_2e emissions from the atmosphere (CCC, 2019a; National Grid, 2019a).

2.3.5. Decentralised low-carbon electricity and gas supply

A decentralised energy system enables the utilisation of low carbon resources such as wind, solar irradiance, waste, and bioenergy to meet energy demands locally. Also, consumers are more likely to take an active part in managing their energy needs with the rollout of smart meters and smart appliances, and via schemes such as demand response, peer to peer energy trading and vehicle to grid services.

In the Community Renewables and Consumer Evolution scenarios, National Grid has projected a rapid increase in decentralised generation capacity to produce more than 50% of national electricity generation by 2050 (National Grid, 2019a). Much of the distribution-connected electricity supply will be renewables (solar PV and onshore wind) and hence the generation patterns will become more weather dependent. There will be an increase in the utilisation of low carbon fuels such as bio-methane through gasification and hydrogen in fuel cells to generate electricity. Biofuels will also be used in Combined Heat and Power units where most of these units will also supply heat into district heating networks. The decentralised generators will have a greater role in providing flexibility and other ancillary services (e.g. frequency response and voltage regulation) to the Electricity System Operator (ESO). The flexibility will be largely used in electricity supply-demand balancing with variable renewable generation.

There will be a growth in green gas connections to the existing gas distribution networks, where gases are produced from crops, agricultural residues, organic materials and domestic waste (Cadent, 2016). Anaerobic Digestion (AD) is already a mature technology that has been used to produce biomethane. BioSNG is produced from non-recyclable waste which is otherwise used as a landfill. Green gas production, therefore, brings in both economic and environmental benefits. However, the scale of deployment is limited due to the availability of feedstock and lack of policy incentives (UKERC, 2019a). With diverse sources of gases, distribution connected gas supply is projected to rise to 109 TWh/year, which is 30 – 50 % of the annual gas supply by 2050 (National Grid, 2019a).

Hydrogen (2% to 20% by volume) blended into the existing gas network (distribution) could also offer a way to reduce the carbon intensity of the gas mixture. Demonstrations are taking place to investigate the potential of blending hydrogen into the natural gas supply (Cadent, 2017). This has been shown initially to require no changes to consumer appliances.

There is a need to establish gas quality measures for gas mixtures from injections of green gases; bio-gas, hydrogen and biomethane to the existing natural gas network (Abeysekera et al., 2016; Peng et al., 2016).

2.3.6. Hydrogen supply

There will be widespread use of hydrogen in the industry, heat supply and transport sectors (CCC, 2019a; National Grid, 2019a). This requires hydrogen production at scale by low carbon electricity or using methane reformation with carbon capture and storage (CCC, 2018a). The National Grid projects that a significant deployment in the use of hydrogen across all sectors would require an annual production of hydrogen up to 324TWh/year by 2050 (National Grid, 2019a).

Hydrogen can be produced by steam methane reformation, partial oil oxidation, coal gasification and electrolysis. However, compared with other methods, steam methane reformation with carbon capture and storage and electrolysis are both shown to be low carbon and cost-effective methods of producing hydrogen at scale (CCC, 2018a).

Electrolysis plants powered by renewable electricity generators (wind and PV) can use excess electricity (when generation exceeds demand) which would otherwise be curtailed, to produce hydrogen. However, studies discuss that the intermittency in renewable generators may limit the availability of excess electricity to produce hydrogen (Hanley et al., 2018). Hydrogen demand for industry, heating and transport will increase and continuous production of hydrogen at scale will be required. Methane reforming has been shown to be commercially competitive to produce hydrogen at scale compared with electrolysis (Parra et al., 2019). However, methane reforming facilities need to have carbon capture and storage to mitigate carbon emissions during the production process.

There is an unresolved challenge on the delivery of hydrogen. Options include – decentralised hydrogen production at a small scale near sources of demand (industrial), blending hydrogen with natural gas, and a dedicated pipeline system for hydrogen (BEIS, 2018b; CCC, 2018a). The impacts on the pipe material by injecting hydrogen into the natural gas transmission network was studied by National Grid (National Grid, 2019b). Physical tests and trials are underway to enable the construction and physical operation of a 100% hydrogen network (SGN, 2019), and blending hydrogen (20% by volume) into the existing natural gas distribution network (Cadent, 2019).

The use of 100% hydrogen requires significant changes to appliances at the consumer level. Initiatives are taking place to assess the technical feasibility of replacing natural gas systems to use hydrogen for heating in residential and commercial buildings (BEIS, 2019c). Expansions to the UK's hydrogen re-fuelling infrastructure is proposed to deploy hydrogen fuel cell vehicles (OLEV, 2019).

2.4. Limitations and challenges of options to decarbonising the UK energy system.

The analyses from the Committee for Climate Change (CCC, 2019a) and the future energy scenarios from National Grid (National Grid, 2019a) show that the use of low carbon electricity, green gases, bioenergy and hydrogen are all essential to decarbonise the UK energy system. Several reports (BEIS, 2019a; UKERC, 2019a) have highlighted the limitations of these options in terms of practical delivery and carbon reduction potential. These limitations are summarised as,

- Section 2.3.1 - technology readiness and supply chain constraints
- Section 2.3.2 - residual environmental impacts
- Section 2.3.3 - capital costs
- Section 2.3.4 - government policy and incentives
- Section 2.3.5 - public acceptance

2.4.1. Technology readiness and supply chain constraints

The use of hydrogen in boilers to produce heat and in fuel cells to produce heat and electricity are important options in heat decarbonisation. However, hydrogen boilers and fuel cells are still being demonstrated across several projects to replace the existing natural gas heating systems in residential and commercial buildings (BEIS, 2019c).

Hydrogen production and transportation infrastructure in the UK are limited (CCC, 2018a). Hydrogen production via electrolysis has yet to demonstrate its technical viability and commercial competitiveness at a large scale (BEIS, 2019d). The use of electrolysis would need investment in electricity transmission infrastructure to access a significant amount of excess renewable electricity. Hydrogen transportation options are being trialled for their technical viability. These trials include the operation of a pure hydrogen network (SGN, 2019) and blending hydrogen into the existing natural gas network (Cadent, 2019). Hydrogen-fuelled end-use technologies, the cost-effective production of hydrogen and its safe delivery would all need rapid development during the next decade to meet the expected use of hydrogen by 2050.

An assessment from BEIS (BEIS, 2019e) reports that the technology readiness of pre-combustion carbon capture technologies is lower than for the post-combustion carbon capture technologies. National Grid envisages pre-combustion carbon capture to reduce emissions from large-scale hydrogen production using methane reforming. Direct air carbon capture and storage has the potential to capture carbon dioxide in the atmosphere but is at an early stage of development in the UK (National Grid, 2019a). Also, it is a highly energy-intensive process that will require a significant electricity demand if deployed at scale.

The CCC in their assessment of bioenergy (CCC, 2018c) discusses the need for a sustainable feedstock supply chain to generate low-carbon electricity and produce green gases (biosynthetic natural gas, biohydrogen, biomethane). Bioenergy with carbon capture and storage will help to offset the residual emissions from hydrogen production such that the “net-zero” emissions target is achieved by 2050 (National Grid, 2019a). The bioenergy resource that is available in GB is limited by what can be grown or imported (BEIS, 2019f). In addition, bioenergy is not currently cost-competitive with fossil fuels and there is uncertainty over long-term biomass resource availability.

2.4.2. Residual environmental impacts

In most future energy scenarios, consideration of the environment and ecosystem services are limited to climate regulation, food, water resources, and air quality. However, solving the carbon problem will be at the expense of creating residual environmental impacts such as biodiversity loss and environmental degradation unless there is a close link between energy and wider ecosystem impacts (Holland et al., 2018). (Hooper et al., 2018) discuss that land-use change (e.g. for bio-energy crops) and sea use change (e.g. for offshore wind farms) are one of the greatest causes of environmental degradation. A review of UK energy policy (UKERC, 2019a) highlights that the plans to meet net-zero CO_2 emissions should also assess and mitigate the negative impacts on ecosystems.

The environmental impacts of shale gas exploration have been a controversy since the discovery of shale gas resources in the UK. The UK will need additional natural gas supplies if hydrogen is to be produced at scale using steam methane reforming. Up to 30bcm/year of shale gas[2] is assumed in the National Grid “Consumer Evolution” scenario (National Grid, 2019a). This requires extensive exploration and production of shale gas using hydraulic fracturing. The impacts of this process include fugitive methane emissions during drilling, waste management (chemicals), possible risk of contaminating groundwater

[2] Natural gas that is found in shale rock. It is extracted by injecting water, sand and chemicals into the shale rock to create cracks or fractures so that the shale gas can be extracted. This process is called “Hydraulic Fracturing” or “Fracking”.

and physical effects. With the current level of public concern, the future availability of shale gas remains uncertain.

The use of hydrogen to replace natural gas for heating would not be a completely zero-emission solution, due to the residual emissions created by a large production of hydrogen using fossil fuels with CCS (95% of CO_2 captured in the process). The limited surplus of low-carbon electricity for use in electrolysers would not be enough to meet the increasing hydrogen demand for heating, thus requiring natural gas reforming with CCS to produce hydrogen. If steam methane reforming is used widely, the overall emissions savings may be insufficient to meet long-term emission targets (CCC, 2018a).

2.4.3. Capital costs

The Committee for Climate Change in their net-zero analysis (CCC, 2019a) shows that there would be an additional £15-20 billion capital investment by 2050 to decarbonise the heat supply in buildings, establish carbon capture and storage infrastructure and low-carbon hydrogen production at scale. The CCC analysis recommends innovation and thus reduce capital costs in these areas, which would otherwise occupy an extra 1-2% of the UK GDP.

The National Grid reports that the technologies available to decarbonise heating in GB, such as heat pumps and hydrogen boilers entail large upfront costs for the consumers compared to the existing natural gas boilers (National Grid, 2019a). The upfront costs of heat pumps come from the costs for the main unit, ancillary parts and installation. Only 17,000 heat pumps were installed in 2017 which was 1% of the number of new gas boilers installed in the same year (BEIS, 2019b). BEIS in their assessment of low-carbon heat technologies reports that cost reductions for heat pumps by 20% would be possible if they reach "mass-market adoption" and reduce unit costs through economies of scale. As heat pumps work at low temperatures, existing buildings with low-thermal efficiency may require improving the level of insulations before installing a heat pump, and thus incur additional costs.

Some components of hydrogen boilers can be adapted from existing technologies (e.g. burners from natural gas boilers and flame failure detection system from the industry). Hence, the capital cost for a hydrogen boiler unit can be reduced (BEIS, 2019b). However, these have not yet been put into a packaged system that is suitable for large-scale adoption. The ongoing hydrogen heating trials are yet to provide insights into where the innovation is needed and hence reduce capital costs to deploy at scale (CCC, 2018a).

A key barrier to the wider uptake of district heating is the high initial capital investment. The largest share of the capital investment (more than 60%) is required for the civil engineering work of excavating and reinstating trenches for hot water pipes, and the connection to the consumers (BEIS, 2018c). The remainder of the costs is for the energy centre which can use gas CHP units, energy from waste facilities or large-scale heat pumps. A study from the Energy Technology Institute (ETI, 2017a) suggests that low-temperature heat networks and trenchless technologies would help to reduce the overall heat network capital costs. However, these need further innovation and demonstration, if heat networks are to play a major role in decarbonising urban areas in the UK (BEIS, 2019b).

High upfront costs are projected for implementing carbon capture technologies and connecting to CO_2 transportation and storage infrastructure (Daggash et al., 2019). A BEIS study on Carbon Capture technologies (BEIS, 2018d) states that the capital costs of pre-combustion carbon capture are higher than post-combustion carbon capture, due to the costs of additional feedstock handling and chemical treatment facilities. The CCC in their net-zero analysis (CCC, 2019a) states that industrial carbon capture demonstration programmes are important for driving innovation and for mitigating the high capital costs of CO_2 capture technologies and CO_2 transportation infrastructure.

The capital costs of novel reformer technologies for hydrogen production, such as Auto Thermal Reformers (ATR) and Gas Heated Reformers (GHR) are higher than conventional Steam Heating Reformers (BEIS, 2019e). Despite their high capital costs, the novel reformer technologies are shown to be able to produce purer hydrogen and capture CO_2 in larger quantities.

2.4.4. Government incentives and policy support

Several reports (BEIS, 2019a; CCC, 2019a; NIC, 2018b) suggest that there needs to be an integrated policy and regulatory design, and implementation across government departments such as the Department of Business Energy and Industrial Strategy, Department for Transport and Ministry of Housing Communities and Local Government. This is mainly because the solutions for a net-zero future are cross-sectoral. For example, the use of hydrogen to reduce emissions is applicable in the heat supply, industry and transportation sectors. Therefore, if hydrogen is to be used to decarbonise each sector, investment and policy decisions by all related departments would need to be compatible (CCC, 2019a).

The UK Energy Research Centre in their recent report (UKERC, 2019a) discusses the need for an urgent review of the Renewable Heat Incentive, the Heat Networks Investment Project, and other initiatives that are due to close in the early 2020s. A redesign of these policies to deliver low-carbon heating technologies with a focus on heat pumps, biomethane and hydrogen, and district heating is recommended. The incentives on district heating would need to allow the use of fossil fuels, to begin with, develop the network and later encourage a smooth transition to a low-carbon heat source (National Grid, 2019a).

Strong incentives and policy supports are required to obtain benefits from vehicle to grid services utilising the EV batteries (Shi et al., 2019). A report from BEIS (BEIS, 2018e) discusses the value of linking smart EV charging to existing residential demand-side management schemes. It was shown that both DSM (including smart charging) and V2G schemes are beneficial in supply and demand balancing of a low-carbon electricity system that is predominantly driven by renewables.

Government incentives are needed to grow the market share for anaerobic digestion plants. Consequently, further innovation and deployment of anaerobic digestion plants could lead to large scale and cost-effective production of biomethane. The UK government support to regulate the distributed injection of biomethane and hydrogen (blending) can help to decarbonise heat supply (CCC, 2018c).

Incentives and policy support are required for rapid decarbonisation of the industrial sector, notably in demonstrating and deploying electrification, hydrogen, and carbon capture and storage technologies (UKERC, 2019a). Strong policy support to use low-carbon electricity for low-temperature industrial heating and the use of hydrogen for higher-temperature combustion have significant potential to reduce emissions. BEIS in their report (BEIS, 2019g) highlight that the industrial sector is not compensated for the technical and reputational risk of delivering lower quality products as a result of failed innovations or the unforeseen impacts of using technologies with low technology readiness level. Thus, the industrial sector is taking a "wait and see" approach that slows down the adoption of low-carbon technologies and products.

Unless there is clear policy support to remove the uncertainties in the development of carbon capture and storage in the UK, investment in large scale hydrogen production from methane reforming and coal gasification are unlikely (BEIS, 2019d). If there is to be widespread use of hydrogen, incentives would help to develop seasonal hydrogen storage in salt caverns and short-term storage as line-pack in transportation pipelines (CCC, 2018a).

2.4.5. Public acceptance

Public acceptance is vital for the switch to low-carbon heating technologies (CCC, 2019a). However, not all options come with an easy and cost-effective replacement for the exiting gas boiler systems. To provide the same level of comfort to a building occupier as a gas-fired boiler, a heat pump, in general, needs to be combined with significant improvements in building insulation and additional equipment to deliver low-temperature heat (larger pipework and potentially underfloor heating) (ENA, 2019). Insulation improvements such as underfloor insulation or solid wall insulation cladding can be both highly disruptive and expensive. The use of "Hydrogen ready" boilers would be similar to a like for like replacement and would have a fairly limited difference in both cost and disruption to installing a new natural gas boiler (UKERC, 2019b). However, National Grid (National Grid, 2019a) projects that using hydrogen as a fuel would be expensive compared to both electricity and natural gas.

Given the disruptions to the households and the high costs (capital and fuel) of low-carbon heating technologies compared to natural gas boilers, consumers are reluctant to change their existing heating systems (Carmichael, 2019). The understanding of the public is, therefore, necessary on why and what changes are needed to change their heating system and to see the benefits in the long-term to a wider energy system (BEIS, 2019b).

Skills support is needed for designers, builders and installers for low-carbon heating technologies, energy and water efficiency, ventilation and thermal comfort (UKERC, 2019a). This helps the installations of heat pumps and hydrogen boilers to be of high standards and fail-proof. With sufficient skill, the public would be encouraged to make changes to their existing heating systems and use low-carbon heating technologies (BEIS, 2019b; Carmichael, 2019).

Several reports (CCC, 2019a; National Grid, 2019a) list out actions that the public can take to reduce their carbon footprint of day to day activities. One way is by making changes in travelling methods such as walking and cycling, switch to EVs and minimise air travel. In houses, people can improve energy efficiency by using LED bulbs and smart appliances, and by controlling temperature hot water temperature in the heating system. A collective effort from the public could make a significant leap in emissions savings.

2.5. Summary

There is a rapid transition in the GB energy system to achieve the “net-zero” emissions targets by 2050. This requires the use of low-carbon electricity and “green gases” such as biomethane and hydrogen across industry, heating, and transport sectors. Low-carbon electricity generation is to be dominated by renewables (offshore wind) and any remaining fossil-fuelled plants are to be equipped with carbon capture technologies. A rapid increase in decentralised electricity generation is expected where the majority is onshore wind and PV plants. Options to decarbonise the natural gas supply system include decentralised injection of biomethane and hydrogen. In the heat supply sector, the use of natural gas boilers will be replaced by alternatives such as hydrogen boilers, waste heat driven district heating systems and heat pumps driven by low-carbon electricity. Widespread use of hydrogen for transport, heating and industrial processes requires large scale hydrogen production by methane reformers and electrolysers. The development of CCS infrastructure is essential to mitigate the residual emissions of hydrogen production, industrial processes, and electricity peaking plants.

The limitations and challenges of low-carbon options to decarbonise the GB energy system need to be addressed such that the statutory emission target is achieved by 2050. Government financial incentives and policies would help innovation, remove costs and market barriers of low carbon technologies, and encourage the public to reduce their carbon footprint. The decision-making processes have been supported with evidence provided by analysis of future energy systems.

The modelling and analysis of energy systems have been traditionally independent. However, it is evident from the current energy transition that future electricity, natural gas, heat and hydrogen supply systems will be interdependent. The integrated modelling of different energy supply systems, as well as the transport sector, will be needed to provide evidence on impacts, cost and environmental benefits of different low carbon options to decarbonise the GB energy system.

3. A review of modelling integrated energy systems

The state of the art of modelling methods used in the design, planning and operation of integrated electricity, natural gas and heat supply systems is presented. The review covers the prevailing tools used for integrated energy systems modelling and concludes with a summary of the limitations and research gaps that have been identified.

3.1. Introduction

The transition to becoming "net-zero" in carbon emissions will create an energy system where electricity, natural gas, heat, and hydrogen supply systems are interdependent as shown in Figure 3.1.

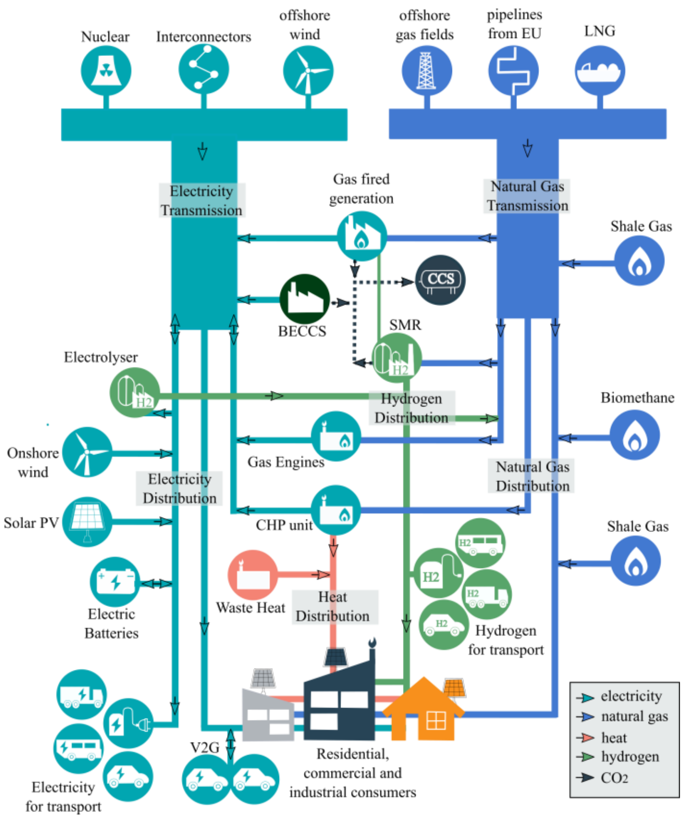

Figure 3.1 – An example of future integrated electricity, natural gas, heat and hydrogen supply systems

As shown in Figure 3.1, the existing interdependencies between electricity, natural gas and heat supply systems are likely to increase with the growing use of hydrogen and bioenergy. Hydrogen production from electricity and natural gas creates new interdependencies between electricity, natural gas, and hydrogen supply systems. Several reports (CCC, 2019a; National Grid, 2019a; UKERC, 2019a) discuss that these interdependencies would help to deliver against all aspects of the "trilemma"- affordability, reliability and sustainability of future energy systems.

3.2. Steady-state modelling and simulation of integrated energy systems

Modelling of energy supply systems in their steady-state has been traditionally considered for electricity, natural gas and heat supply systems individually. Steady-state power flow, natural gas flow, and hydraulic-thermal calculation methods have been used to model and simulate electricity, natural gas and heat supply systems under steady-state conditions.

However, these different energy systems are coupled with energy conversion technologies such as gas-fired generators, gas boilers, heat pumps and combined heat and power units. The coupling of different energy systems makes them interdependent. Hence, integrated simulations are needed to investigate the benefits and impacts of an integrated electricity, natural gas and heat supply system (Mancarella, 2014b).

The solutions for integrated electricity, natural gas and the heat supply system are obtained by two methods. One is a decomposed method that solves independent power flow, gas flow and hydraulic-thermal equations sequentially. Second is an integrated method that solves the combined power flow, gas flow and hydraulic-thermal equations simultaneously (Liu, 2013).

3.2.1. Network-based modelling and simulation of integrated energy systems

The power flow, gas flow and hydraulic-thermal modelling use energy networks. The networks are represented by nodes and branches drawn as line segments connecting the nodes. Nodes represent the locations of demands and supply for each network. The branches represent gas pipelines, hot water pipelines and electricity distribution lines. An example of integrated electricity, natural gas and district heating network is shown in Figure 3.2.

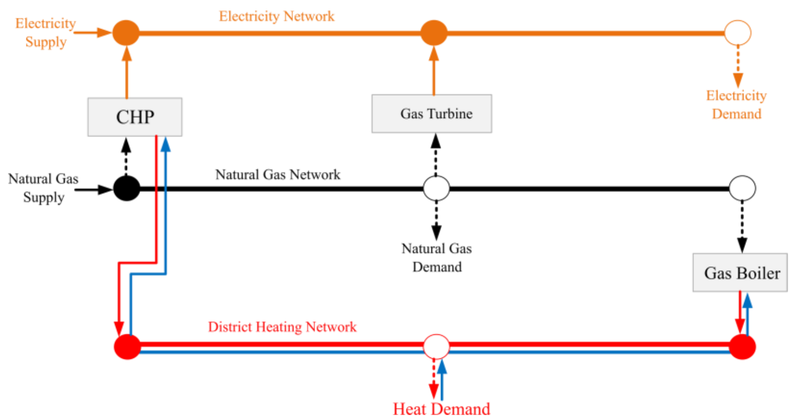

Figure 3.2 – An example of integrated electricity, natural gas, and district heating network

In Figure 3.2, the filled circles represent supply nodes and solid arrows denote the supply of electricity, gas and heat. The non-filled circles represent demand nodes and dashed arrows denote the demand for electricity, natural gas, and heat. The blue line denotes the return line in the heat network. The networks are coupled through a CHP unit, a gas turbine, and a gas boiler.

The modelling of the natural gas network uses the mathematical equations governing gas flow in pipes, and nodal gas flow balance (Osiadacz, 1987). Under steady-state, changes in temperature and velocity of natural gas against time and pipe dimensions are assumed to be constant. The parameter to compute in the natural gas network is the gas pressure at all gas network nodes. The nodal gas pressure allows the calculation of natural gas flow rates in gas pipes.

The steady-state modelling of the electricity network using the AC power flow stipulates that, at each node, the power injected by generators, the power demand, and power flow through the lines connected to the node must add up to zero. This is applied to both active and reactive power (Wood and Wollenberg, 1996). The steady-state DC power flow modelling simplifies the AC power flow formulations by assuming that, (i) the voltage angle differences are very small between nodes, (ii) the nodal voltage magnitudes are constant, and (iii) line resistance is very small compared to line reactance (McDonald and Wang, 1994).

The district heating network is modelled using hydraulic equations that describe the water mass flow rate through pipes (supply and return) and water pressure at each node. The thermal modelling of the heat network uses the water mass flow rate to calculate thermal power, and temperature of the water flow in supply and return pipes.

The coupling components of the integrated system are modelled as a simple energy conversion across a conversion efficiency (Abeysekera and Wu, 2015; Liu and Mancarella, 2016). For example, a gas turbine converts natural gas energy to electrical energy through the electrical efficiency of the gas turbine. This couples the natural gas demand for power generation at the connected natural gas network node, and the electrical power output at the electricity network node. The combined steady-state simulation of the integrated electricity, natural gas and heat network system formulates a combined set of equations to compute the steady-state parameters in each network considering the energy exchanges introduced through network coupling (Abeysekera, 2016).

In the first integrated solution method, the electrical power flow, natural gas flow and hydraulic-thermal equations are solved sequentially. The solutions of state variables of one system are used through the coupling relationships to solve the unknown variables of the coupled system. For example, the power flow analysis provides the electricity output of a gas turbine, and it is then used to calculate the unknown gas demand at the connecting node of the gas network. The sequential solution to a coupled electricity and natural gas network system was used in (Rubio-Barros et al., 2010). In (Liu, 2013) the sequential solution was applied for a coupled electricity and district heating network.

The second integrated solution method requires the power flow, gas flow and hydraulic-thermal equations to be solved simultaneously (Abeysekera, 2016). The coupling relationships are used, for example, to define the power output of a gas turbine in the electrical power flow equations as a function of the natural gas demand at the connecting node of the natural gas network. The combined equations are then solved simultaneously using the Newton-Raphson method. In (Martinez-Mares and Fuerte-Esquivel, 2012), the Newton-Raphson method was used to obtain an integrated solution to a combined electricity and natural gas network. Combined power flow and hydraulic-thermal equations were solved simultaneously using the Newton-Raphson method (Liu et al., 2016). A similar approach was used to solve combined electricity, natural gas and district heating network systems (Abeysekera and Wu, 2015; Liu and Mancarella, 2016).

Instead of steady-state, dynamic modelling and simulation are commonly used to model the natural gas system. This allows the calculation of gas storage capacity within the transport pipelines, also known as linepack.

3.2.2. Energy Hub modelling and simulation of integrated energy systems

The “Energy Hub” concept was introduced by (Geidl, 2007) as a generic framework for steady-state modelling and simulation of integrated energy systems. Figure 3.3 shows the energy hub modelling of an example integrated electricity, natural gas and district heating network system.

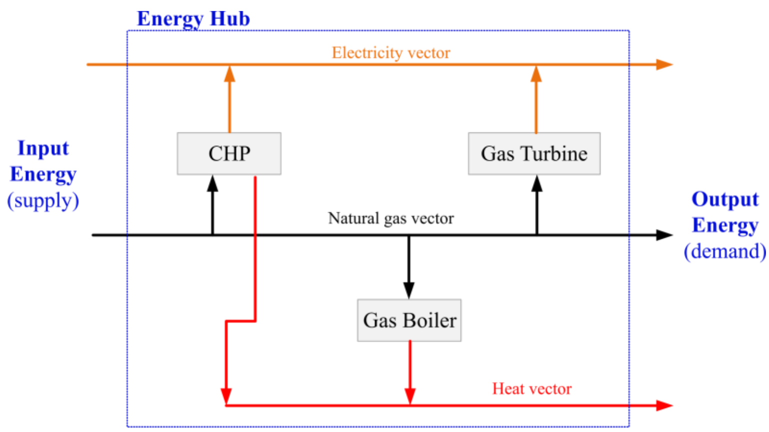

Figure 3.3 – Energy hub representation of integrated electricity, natural gas and district heating system with a CHP unit, gas turbine, and a gas boiler as coupling components

An energy hub models the energy supply and conversion to meet energy demands in a steady state. As shown in Figure 3.3, input electricity and natural gas are used in combination with the outputs from the CHP unit, gas turbine and gas boiler to meet electricity, natural gas and heat demand. Energy conversion from one form to another is characterised by the energy efficiency of the technology (Geidl and Andersson, 2007a). Within an energy hub, it is assumed that losses occur only in conversion elements (Geidl, 2007).

The mathematical formulation of an energy hub is the equations for steady-state supply and demand balance of electrical, natural gas and heat energy. The individual energy balance equations are combined with energy conversion relationships and solved simultaneously (Arnold and Andersson, 2008).

Energy hub modelling has been applied to model integrated energy systems in buildings (Brahman et al., 2015), community-level (Ma et al., 2017) and national level (Krause et al., 2011). In addition to the supply and conversion of energy, energy storage units such as batteries, gas storage units and hot water tanks are modelled depending on the application.

3.3. Optimisation of integrated energy systems

A simulation model of an integrated energy system emulates the behaviour of the system under certain assumptions. In contrast, an optimisation model searches for the optimal operating conditions or the optimal design of an integrated energy system within a feasible solution space to meet a certain objective (Lund et al., 2017).

An optimisation model is therefore characterised by an objective function and a set of equality and inequality constraints. Commonly chosen objectives include minimisation of energy costs (total operating costs and/or investment costs), or minimisation of total emissions of the integrated energy system (Mancarella et al., 2016).

3.3.1. Optimisation with network-based constraints

The equality constraints for the integrated network optimisation are derived from the steady-state electricity power flow, gas flow and hydraulic-thermal equations (Biskas et al., 2016). Inequality constraints define the minimum and maximum limits of a system variable (e.g. maximum power generation limit, maximum and minimum gas pressure). These constraints are typically derived for a single timestep.

Multi-time period optimisation models have been developed to study natural gas storage within pipelines (linepack) and storage facilities in the natural gas network, and unit-commitment of electricity generators in the electricity network. The storage variables and unit-commitment variables combine successive time periods (e.g. an hour of the day) of the optimisation problem. To model the gas storage, multi-time period steady-state modelling (Chaudry et al., 2008) or multi-time period transient-state modelling (Liu et al., 2011) methods have been used.

3.3.2. Optimisation with energy hub constraints

In the case of energy hub modelling, the equality constraints are derived from the energy supply-demand balance equations for electricity, natural gas and heat. The minimum and maximum limits of input energy to the energy hubs and energy outputs of coupling components provide the inequality constraints (Geidl, 2007).

When the optimisation of storage elements and the use of unit commitment is needed, multi-time period optimisation of energy hubs is performed. Multi-time period optimisation of energy hubs with storage elements was presented in (Arnold and Andersson, 2008) and unit commitment was used in (Jin et al., 2016).

3.3.3. Solving the optimisation problem

The mathematical optimisation model is typically developed in software packages and is solved using built-in optimisation solution tools or algorithms.

Complex optimisation problems are often simplified using mathematical techniques before implementing them using software tools. These different mathematical techniques of solving the optimisation problems enable the user to approach a difficult or complex problem through a simpler and relaxed problem. Relaxation methods such as Lagrange relaxation and benders relaxation offers simple subproblems which can be solved in parallel and faster than the original problem. The Lagrangian relaxation method was used in (Liu et al., 2010) to provide approximate linear constraints to the original non-linear integrated electricity and natural gas optimisation problem. Decomposition techniques are often used to separate multi-objective optimisation problems to create single objective subproblems. For example, the Benders decomposition method was used in (Alabdulwahab et al., 2015; Zhang et al., 2015) to simplify a large linear investment and operational model of an integrated gas and electricity system. The decomposed master investment problem and operational subproblems were solved iteratively until an optimal solution was obtained.

As software tools to develop the optimisation problems, GAMS was used in (Munoz et al., 2003; Quelhas et al., 2007) to model integrated electricity and natural gas system, and the CPLEX iterative algorithm was used to solve the optimisation problem. FICO Xpress (formerly known as Dash Xpress) and its Sequential Linear Programming (SLP) solver were used in (Chaudry et al., 2008; Qadrdan et al., 2010b) to study an integrated electricity and natural gas network. The use of software tools such as GAMS and FICO is becoming quite popular to build optimisation problems and are equipped with different solvers to solve complex non-linear optimisation problems. This often replaces the need to use relaxation and decomposition techniques to simplify complex optimisation problems.

3.4. Analysis of integrated energy systems

Integrated simulation and optimisation modelling methods are typically applied to perform operational analysis and expansion planning of integrated energy systems (Erdener et al., 2014). Table 3.1 provides examples of the research questions in each area of study.

Table 3.1 – Example research questions considered in the analysis of integrated energy systems (Abeysekera, 2016)

Analysis		Example research questions
Operational analysis	Operation scheduling/optimisation **(3.4.1)**	What is the optimal way to operate integrate energy systems to meet an objective (e.g. cost minimisation, CO_2 minimisation)?
	Operational interdependencies **(3.4.2)**	What are the operational interdependencies that may occur from the integration of energy systems?
	Flexibility provision by demand response and ancillary services **(3.4.3)**	What are the potential opportunities to provide real-time demand response and ancillary services through the integration of energy systems?
Design and Expansion Planning **(3.4.4)**	Greenfield design	What are the most cost-effective structure and sizing of the system components to meet the multi-energy demands?
	Expansion planning	What is the optimal way to invest in the expansion of energy infrastructure considering future multi-energy demands?

3.4.1. Operation scheduling of integrated energy systems

Operational scheduling provides reliable and cost-effective operation of the integrated energy system. Traditional concepts in the electricity system such as unit commitment, economic dispatch and optimal power flow have been applied for the operation scheduling of integrated energy systems.

Unit commitment determines an optimal start-up and shut-down schedule for electricity generation plants to meet the forecasted demand profile subject to constraints in the electricity network. Economic dispatch determines the optimal output of scheduled electricity generators at the lowest possible cost. The optimal power flow combines the economic dispatch calculations with steady-state power flow equations and solves them simultaneously. Mathematical optimisation with network-based constraints and energy hub constraints are both commonly used for these studies.

The unit commitment of electricity generators in integrated electricity and natural gas system was developed in (Fu et al., 2005a; Li et al., 2008). The unit commitment of electricity generation was subjected to constraints in the electricity system such as minimum spinning reserve, minimum start-up/shut-down times and ramp rates of generation technologies. AC power flow constraints such as bus voltage limits, active and reactive power limits of generators were used in the unit commitment model developed by (Fu et al., 2005b). Illustrative examples were discussed regarding the use of the unit-commitment models on the operation of a vertically integrated utility. The impact of the uncertainties in wind power forecasts on the unit commitment of natural gas-fired plants was studied in (Xydas et al., 2017).

The impact of natural gas prices on the scheduling of gas-fired power generators was investigated by (Shahidehpour et al., 2005). The authors also discussed the impact on electricity prices due to running gas-fired plants with high gas market prices. A dynamic natural gas network model was used in (Zheng et al., 2017; Zlotnik et al., 2017) to develop the coordinated daily operation of natural gas linepack and electricity generation from gas-fired generators. The study showed that the coordinated operation was able to minimise the total operating costs of the integrated electricity and natural gas networks compared to an independent operating strategy.

Unit commitment in an energy hub was described in (Ramirez-Elizondo et al., 2010). The objective was to minimise the cost of external electricity and gas grid supply by optimally scheduling the CHP units, gas boilers, and electricity and heat storage units within the energy hub. The applicability of the optimal scheduling techniques for peak demand shaving and improved use of storage systems were discussed. Scheduling of a network of energy hubs was developed in (Maroufmashat et al., 2015). In this study, the unit commitment of each energy hub was used to minimise the total operating cost of the energy hub network. The study showed that the optimal scheduling was able to reduce natural gas consumption, and consequently reductions in emissions and economic benefits.

The economic dispatch and optimal power flow methods for integrated energy systems were introduced with the energy hub concept (Geidl and Andersson, 2007b). The cost-optimal output of energy supply (external power and gas grid) and conversion technologies (CHP and gas boiler) in the energy hub was obtained to meet electricity, natural gas, and heating demands. The use of economic dispatch and optimal power flow for a community level integrated electricity, natural gas and district heat network system was presented in (Ramirez-Elizondo and Paap, 2009) and (Beigvand et al., 2017). An optimal power flow model for an integrated gas and electricity networks was developed in (Chaudry et al., 2008; Clegg and Mancarella, 2014).

3.4.2. Interdependencies in the operation of integrated energy systems

Today, the interdependencies between electricity, natural gas and heat supply systems are primarily due to the use of natural gas in electricity generation and heat supply. These interdependencies are likely to increase with the use of hydrogen and bioenergy in future low-carbon energy systems. Integrated energy systems modelling has been used to analyse these interdependencies between different energy systems. Electricity and natural gas network-based optimisation models are commonly used to investigate detailed interdependencies of integrated energy systems.

The impacts of variable renewable generation on the natural gas supply system was studied in (Qadrdan et al., 2010b; Qiao et al., 2016). The variability in wind generation caused rapid ramping in gas-fired generator outputs. Hence, impacts were shown on the gas linepack, gas supply and the operation of compressor stations in the gas network. The dynamic variations in pressure of the natural gas network due to the rapid ramping of gas-fired power generators were studied in (Chertkov et al., 2015; Zhou et al., 2017).

Qadrdan (2017a) compared the feasibility of gas-fired plants, electricity storage and power-to-gas systems to balance the variability in wind power output. Electricity storage was shown to provide the highest reduction in combined electricity and gas network operating costs. Several studies (Clegg and Mancarella, 2015; Qadrdan et al., 2015a) examined the interdependencies caused by power-to-gas units on the integrated electricity and natural gas network operation. These studies further demonstrated the technical, environmental, and economic operational aspects of power to gas in the case of Great Britain’s system.

Interdependencies on the operation of local electricity, natural gas and heat networks with the co-generation of electricity and heat using CHP units were investigated (Ma et al., 2017). The authors demonstrated that the integrated system allows more renewable energy penetration and increased utilisation of energy storage systems. In (Liu and Mancarella, 2016), interdependencies between electricity, natural gas and heat networks were studied for different levels of CHP and heat pump penetration. Sankey diagrams were used to show the interactions between the three networks both qualitatively and quantitatively. The impacts on district heating and natural gas network operation due to a large penetration of variable renewable electricity generation were investigated by (Kusch et al., 2012; Vandewalle et al., 2012). The benefits of operating energy storage (battery and thermal) across integrated electricity, natural gas and district heating network system were demonstrated to ensure energy supply security.

3.4.3. The potential to provide flexibility to the electricity system by integrated energy systems

The flexibility of the electricity system refers to the ability of electricity generation and consumption to adjust and maintain within a given period (Bell and Gill, 2018). In integrated energy systems, the flexibility to the electricity system is provided by the storage in the gas network (linepack), or by the provision of real-time demand response by using the interdependencies between electricity, gas and heat supply systems (Carbon Trust and Imperial College, 2016).

An investigation of the ability of the gas network to provide electricity system balancing via rapid-ramping of natural gas-fired generators was carried out by (Ameli et al., 2017). The flexibility of the gas network was provided by gas-linepack and via bi-directional compressor stations allowing the system operator to redirect gas flows through the network. The evaluation of integrated gas and electricity network flexibility accounting for the changes in the heating sector was presented in (Clegg and Mancarella, 2016). The gas network flexibility was assessed by linepack availability across different regions of the gas network, and its consumption by gas-fired generators. National Grid (2019) reported that the flexibility of the operation of the gas network may change in the future over the choice of low carbon heat supply technologies and the use of natural gas to produce hydrogen generation.

Mancarella and Chicco (2013) developed a framework to assess the provision of real-time demand response from the integration of energy systems. An “electricity shift potential” was introduced as an indicator of the possible reduction of electricity flowing from the external grid to the integrated energy system. A similar study was carried out in (Martínez Ceseña *et al.*, 2016) to assess the provision of real-time demand response to the external power grid by an integrated district energy system with CHP units and thermal storage. In this study, the demand-response provided to the external power grid was quantified under uncertainties in electricity and natural gas prices.

3.4.4. Planning of integrated energy systems

The planning of an integrated system requires the optimal combination of energy supply, conversion, and storage technologies as well as the network infrastructure required to meet the estimated demands in future. Traditionally, the design and expansion planning has been performed for electricity, natural gas, and heat supply systems independently. The increasing interdependency between different energy systems requires integrated planning such that optimal investment decisions are made (CCC, 2019a). Almost all planning problems of integrated energy systems are designed as optimisation problems with both network and energy hub-based constraints. The objectives often found in the literature are to minimise the total investment costs are to minimise the overall CO_2 emissions over the planning time horizon.

Chaudry (2014) presented a model to analyse GB gas and electricity infrastructure expansion requirements to achieve a low carbon energy system. The same model was used by Qadrdan (2017) and investigated the impact of demand-side response on the expansion planning of GB electricity and gas transmission networks. The study showed that due to the shaving of electricity peak demand via demand response, the investment in natural gas-fired generation capacity was significantly reduced. Consequently, natural gas imports were reduced due to the reduction in gas use for power generation. Expansion planning of integrated gas and electricity transmission system was presented for Brazil (Unsihuay-Vila et al., 2010) and Iran (Barati et al., 2015). Both studies highlighted the economic benefits of combined planning of electricity and natural gas networks over the independent planning approach. The impact of electricity and natural gas prices and the mismatch of gas and electricity market timelines on the planning of integrated electricity and natural gas networks to meet long-term energy demands were studied (Qiu et al., 2015). A probabilistic approach was used in (Odetayo et al., 2017) to consider the uncertainties in active and reactive power demand for the expansion planning of integrated gas and electricity networks. The authors showed that the combined approach provides acceptable results when employed in planning simple and complex electricity and gas distribution systems.

The planning of integrated electricity, natural gas and district heating infrastructure for new build schemes with carbon emissions constraints was presented in (Rees et al., 2014). In this study, network and building-level energy supply technologies were chosen to meet energy demands and carbon emissions targets while minimising investment costs to the developer. Optimal sizing of CHP units and their locations on the integrated electricity, gas and district heating network were considered in the planning model presented by (Jia, 2016). The optimal locations of CHP units were determined by minimising the losses in the electricity and district heating networks. The planning of integrated electricity, natural gas and district heat network systems was described in (Mohsenzadeh et al., 2016) such that both investment and operating costs were minimised. It was shown that the optimal sizing of and location of CHP units showed a significant reduction in both operating and planning costs compared to an arbitrary locating of CHPs.

Planning of a residential energy hub was presented in (Fabrizio et al., 2010). In this study, a model was used to minimise life-cycle costs including investments to select an optimal mix of technologies for the building to meet electricity, heating and cooling demands. Sheikhi (2012) developed a similar model, but for optimal sizing of an energy hub with combined cooling, heat, and power systems in a commercial building. Optimal planning of a community-level network of energy hubs was studied in (Salimi et al., 2015). In this study, the energy hubs represented electricity and heat supply in buildings, and each energy hub was connected to the electricity and gas distribution networks. The study showed the economic benefits of installing CHPs when a district heating network is available rather than individual heating systems.

3.5. Tools for integrated energy systems modelling

Tools and software for modelling integrated energy systems are typically developed within academia, government departments, consultancy and utility companies (Strachan, 2011). These tools have been used to perform analyses such as design, expansion planning and operation of energy systems considering:

- interdependencies within different energy systems – e.g. electricity and gas
- interdependencies between different infrastructure systems – energy, transport, digital communications, water supply
- uncertainties in energy markets and the evolution of technology development
- possible pathways to decarbonise specific sectors – industry, heat supply and transport.
- the impact of (sometimes competing) policy objectives on the performance of the overall energy system in terms of costs, emissions, and the security of supply.

These tools are used to provide evidence-based insights to design policies and strategic investment decisions to realise future low carbon energy systems.

In the following section modelling tools available in the literature are classified according to the purpose of the tool (e.g. expansion planning), modelling approach, sectoral coverage, geographical coverage, energy system representation, temporal coverage, methodology and mathematical approach. The classification categories used were adopted from several previous studies (Connolly et al., 2010; Hall and Buckley, 2016; Jebaraj and Iniyan, 2006; Pfenninger et al., 2014; Yue et al., 2018). The classification shown in Table 3.2 is designed to be of information required to differentiate between modelling tools (Hall and Buckley, 2016)

Table 3.2 – Variants of classification categories of prevailing integrated energy system modelling tools (Connolly et al., 2010; Hall and Buckley, 2016; Jebaraj and Iniyan, 2006; Pfenninger et al., 2014; Yue et al., 2018)

Category	Description
Purpose of the model	• **Design and Planning:** e.g. analysis of optimal investment to meet emissions targets, expansion of the electricity system to meet future electricity demands • **Operational analysis:** e.g. policy impacts on energy system operation, interdependencies in operating future low-carbon energy systems • **Market analysis:** e.g. analyse the behaviour of the electricity market with high penetration of distributed generation
Modelling Approach	• **Top-down:** Use macroeconomic metrics (e.g. gross domestic product, inflation) to determine growth in energy prices and demands. • **Bottom-up:** Technologies and components of energy systems (e.g. networks) are explicitly modelled with governing physical laws (e.g. mass flow, conservation of energy). • **Hybrid:** Combined top-down economic and bottom-up features are used in the model. The hybrid approach uses a soft link between top-down and bottom-up models or a single integrated framework.
Sectoral coverage and method of representation.	Sectoral Coverage • **Energy:** Electricity, natural gas, heating, hydrogen, bioenergy • **Other:** Transport, Agriculture, Water Supply, Waste management Method (only when two or more different sectors are covered). • **Integrated method**: separate sector models for electricity, gas, heating, transport systems are used and integrated within the tool. (e.g. sector models are - AC/DC flow model, gas flow model, thermal/hydraulic model, transport model). • **Interaction method**: separate sector models are not used, instead, interactions are considered (e.g. gas use for electricity, electricity use for transport etc.)
Geographical coverage	Global, national, regional, community level, demonstration area, building

Representation of the energy system	• **Detailed network model:** Energy supply systems are represented by networks (e.g. Electricity and gas networks). Energy supply and demand is modelled using power flow (AC/DC) gas flow and hydraulic-thermal equations. • **Input-Output model:** Input energy demand in the system is met by energy supply, storage and conversion technologies. A simple energy supply and demand balance are modelled.
Temporal coverage	• Time horizon: Short term (a year or up to 5 years), Medium-term (5 to 20 years), Long term (over 20 years) or Snapshot • Time step: Minute, Hour, Season, Year, Five-year
Methodology	• Optimisation • Simulation
Mathematical approach	• Linear programming / non-linear programming • Mixed-integer programming • Dynamic programming • Fuzzy logic • Agent-based programming

3.5.1. Summary of existing modelling tools

There are several prominent energy systems modelling tools that have been developed over several decades (see Table 3.3). For example, MARKAL (Fishbone and Abilock, 1981) and MESSAGE (Schrattenholzer, 1981) tools have laid the foundation for several other modelling tools which improved their functionality and applicability over time. Table 3.3 lists the energy system modelling tools being utilised at present.

Table 3.3 – Prevailing tools for integrated energy systems modelling

Model	Full Name	Developer and Citation (s)
DECC 2050 calculator	Policy tool from the UK Government	Department of Energy and Climate Change - (DECC, 2010)
DECC DDM	Dynamic dispatch model developed by the UK government	Department of Energy and Climate Change - (DECC, 2012)

DSIM	Dynamic System Investment Model	Imperial College London - (Strbac et al., 2012)
DynEMo	Dynamic Energy Model	University College London - (Barrett and Spataru, 2011)
EnergyPLAN	Advanced Energy Systems Analysis Computer Model	Aalborg University, Denmark. - (Lund et al., 2019; Thellufsen and Lund, 2018)
ESME	Energy System Modelling Environment	Energy Technologies Institute (ETI) - (Heaton and Bunn, 2014)
LEAP	Long-range Energy Alternatives Planning System	Stockholm Environmental Institute, Boston. - (Heaps, 2009; McPherson and Karney, 2014)
MARKAL	MARKet Allocation Model	International Energy Agency - (Fishbone and Abilock, 1981; Loulou et al., 2004)
MESSAGE	Model of Energy Supply Strategy Alternatives and their General Environmental Impact	International Institute for Applied System Analysis (IIASA), Austria - (Messner and Strubegger, 1995)
TIMES	The Integrated MARKAL-EFOM System	International Energy Agency (IEA) – Energy Technology Systems Analysis Programme (ETSAP) - (Loulou et al., 2016)
CGEN	Combined gas and electricity network operational model	(Chaudry et al., 2008)
CGEN+	Combined gas and electricity network expansion planning model	(Chaudry et al., 2014a)

Table 3.4 compares the modelling tools under the classification schema introduced in Tables 3.2.

Table 3.4 – Comparison of existing modelling tools

Model	Purpose	Modelling Approach	Sectoral Coverage and method of representation	Geographical Coverage (a) and representation of the energy system (b)	Temporal Coverage	Methodology (Mathematical Approach)
DECC 2050 Calculator	**Planning:** Planning of future energy system to meet emissions targets	Bottom-up	Electricity, Natural gas, Heat, Bioenergy, Hydrogen, Transport Method: interaction	(a) The UK as a single region. (b) Input-Output model.	Time horizon: over 20 years Time Step: 5-years	Accounting model in a spreadsheet
DECC DDM	**Market analysis:** Analysis of GB power market	Bottom-up	Electricity	(a) GB as a single region (b) Input-Output model.	Time horizon: 5 to 20 years Time Step: Year	Optimisation
DSIM	**Planning and Operation:** Simultaneously optimises long-term electricity system while considering the short-term operation.	Bottom-up	Electricity	(a) GB – Scotland and 3 regions to represent England and Wales. (b) Network model (Transmission and distribution).	Time horizon: Year Time Step: hour	Optimisation (Linear Programming)
DynEMO	**Planning and Operation:** Investigate how society engenders demands for energy services that vary with time and climate, and how energy resources and be deployed to meet the demands.	Bottom-up	Electricity, heat, natural gas, bioenergy and transport Method: interaction.	(a) The UK as a single region (b) Input-Output model	Time horizon: Year – 5 years Time Step: hourly in peak day across 4 seasons per year).	Simulation and Optimisation (Dynamic programming)
EnergyPLAN	**Planning and Operation:** Assist national energy planning strategies based on	Bottom-up	Electricity, Heat and Transport	(a) Flexible: National/ regional	Time Horizon: Year	Simulation and Optimisation

	investment decisions of different technologies and the system operation.		Method: interaction	(b) Input-Output model	Time step: hour	(Analytical programming)
ESME	**Planning:** Searches for optimal energy system designs which minimise investment costs a meeting stipulated emissions targets and a range of other user-specified constraints.	Bottom-up	Electricity, Natural gas, Heat, Bioenergy, Hydrogen, Transport Method: interaction	(a) The UK split into 12 regions (Scotland, Wales and 9 English regions) (b) Input-Output model	Time Horizon: Year up to 50Years Time Step: 5 intraday time slices (overnight, morning, mid-day, early evening, late-evening) across Summer and Winter.	Optimisation (Linear Programming)
LEAP	**Planning:** Assess energy system planning scenarios and policies in terms of cost-benefits and environmental impacts.	Hybrid	Electricity, Natural gas, Heat, Bioenergy, Hydrogen, Transport, Agriculture Method: interaction	(a) Flexible: National, regional (b) Input-Output model	Time Horizon: 5 to 50 years Time Step: Year	Simulation
MARKAL	**Planning:** Perform target-oriented (e.g. emissions reduction) planning of energy system to minimise discounted investment costs.	Bottom-up	Electricity, Natural gas, Heat, Bioenergy, Hydrogen, Transport Method: interaction	(a) Flexible: National, regional (b) Input-Output model	Time Horizon: 20 to 50 years Time Step: User-defined time slices (monthly, weekday/weekend, hourly).	Optimisation (Linear programming)

MESSAGE	**Planning:** Planning of energy systems subjected to long-term climate change policies and long-term national/regional development scenarios.	Bottom-up	Electricity, Natural gas, Heat, Bioenergy, Hydrogen, Transport Method: interaction	(a) Flexible: National, regional (b) Input-Output model	Time Horizon: 20 to 120 years Time Step: 5-Years	Optimisation (dynamic programming)
TIMES	**Planning and Operation:** Generate scenarios for the evolution of the energy system based on minimum investment and system operating costs, subject to policy and environmental constraints.	Bottom-up	Electricity, Natural gas, Heat, Bioenergy, Hydrogen, Transport, Agriculture Method: interaction	(a) Flexible: National, regional (b) Input-Output model	Time Horizon: 5 to 20Years Time Step: User-defined time slices (monthly, weekday/weekend, day/night).	Optimisation (Linear Programming)
CGEN	**Operation:** Perform operational analysis of combined gas and electricity networks	Bottom-up	Electricity and natural gas Method: integration	(a) GB as a single region (b) Network model (Gas and electricity transmission networks)	Time Horizon: Year Time Step: hourly across 4 seasons	Optimisation (Non-linear programming)
CGEN+	**Planning:** Perform expansion planning of gas and electricity networks to minimise investment and operating costs.	Bottom-up	Electricity and natural gas Method: integration	(a) GB as a single region (b) Network model (Gas and electricity transmission networks)	Time Horizon: 5 to 20 years Time Step: 5-year	Optimisation (Non-linear programming)

3.5.2. Common modelling tools

Models are used to prepare policies and strategies regarding the future energy transition (Pye and Bataille, 2016). The Committee for Climate Change and the Department for Business Energy and Industrial Strategy are currently using MARKEL, UK-TIMES and ESME for preparing carbon budgets and strategies on heat (BEIS, 2018b), bioenergy (CCC, 2018c) and hydrogen (CCC, 2018a).

Generic modelling platforms such as MESSAGE, LEAP, EnergyPLAN, MARKAL and TIMES provide the user with the flexibility to create energy system models for any country or region. These tools have been used in several countries for integrated energy system modelling and planning. The UK models developed from these tools include UK-MARKAL (Loulou *et al.*, 2004) and UK-TIMES (Daly and Fais, 2014). In contrast, CGEN/CGEN+, ESME, DynEMO and DSIM tools are specific tools used to study only the GB energy system.

Planning tools are used to support strategic decision making on future energy supply systems to meet climate goals (Hall and Buckley, 2016). MARKAL, EnergyPLAN and ESME are examples of common planning tools. Also, MARKAL and ESME represent a large number of technologies and end-uses to develop future energy system scenarios.

DynEMO and TIMES represent a simplified operation of energy systems in a single node input-output model. Energy supply, storage and conversion are represented to satisfy energy demands at each time step. DSIM and CGEN represent energy networks to model the energy system operation. In DSIM, the electricity networks are modelled with the daily operation of electricity storage and variability in renewable electricity generation. In contrast, CGEN investigates interdependencies in operating integrated electricity and natural gas networks. The CGEN model describes the detailed operation of seasonal gas storage, gas linepack, compressor stations, and power ramping of electricity generators.

The energy system is represented as an input-output model in most tools (Pfenninger et al., 2018). Planning tools (e.g. TIMES, MARKEL, ESME) simplify the national or regional energy systems using an input-output model excluding detailed network infrastructure. The simplified representation of the energy system allows these tools to model a wide range of sectors (electricity, natural gas, heat, hydrogen, bioenergy and transport) and technologies. In contrast, DSIM and CGEN+ include detailed network model and use the location of generators and pipelines. Network modelling is complex and hence limited to planning of the electricity system (DSIM) or integrated planning of electricity and natural gas systems (CGEN+).

The time horizon of planning tools takes into account 50 to 100 years (e.g. ESME, MARKAL and MESSAGE). TIMES uses a shorter planning time horizon up to 20 years and EnergyPLAN uses an annual planning time horizon. The time horizon of operational tools is typically limited to up to a year. DSIM and CGEN provide flexibility to choose the operating time horizon from a day, month up to a season (decided by the number of months).

The time step granularity in planning tools are typically 5-years (e.g. CGEN+, MESSAGE and DECC 2050) or a year (e.g. LEAP). TIMES, MARKAL and ESME tools use monthly or intraday time steps. The intraday time steps represent a specific time of the day (e.g. peak and off-peak, morning, mid-day, evening and night). In contrast, finer time step granularity is used in CGEN, DSIM and EnergyPLAN to capture the variability in renewables, operation of storage systems and the impact of peak energy demand (Lopion et al., 2018).

Optimisation is used in most of the modelling tools. In planning, the optimisation model minimises the total investment cost subjected to policy goals, energy supply-demand balance and long-term emissions constraints (e.g. MARKAL, TIMES and ESME). For the studies of energy system operation, optimisation models (e.g. CGEN) minimises the total operating cost subjected to technical constraints derived from the operation of the energy system.

3.6. Limitations and research gaps in modelling integrated energy systems

3.6.1. Uncertainties and transparency of input data

Several input data sets such as technology development rates, population growth, economic growth, and weather parameters are uncertain (Klosterman, 2012). These uncertainties are typically dealt with through stochastic and Monte-Carlo modelling approaches. The use of these modelling approaches is limited due to the additional complexity they add to large energy system models (Lopion et al., 2018). Alternatively, sensitivity and scenario studies are performed to assess the impact of uncertainties in input data and their impact on model outputs (Yue et al., 2018). Modelling tools such as EnergyPLAN, TIMES, and CGEN allows user to perform Monte-Carlo modelling approaches to deal with uncertainty. Other tools such as DECC 2050, ESME, and MARKAL are quite rich in creating and analysing different scenarios studies. Almost all tools in Table 3.4 allow sensitivity studies.

DeCarolis et al., 2012 and Hawker and Bell, 2019 discussed how to make the input data well documented and accessible. The transparency allows a more informed discussion among modellers and practitioners on the uncertainties regarding input data used to model complex energy systems. Most used modelling tools such as MARKAL, TIMES, MESSAGE, ESME, EnergyPLAN and LEAP are well documented and accessible in public repositories. Few tools such as DSIM, CGEN/CGEN+ use proprietary licences limiting the accessibility to the model and data.

3.6.2. Coarse spatial and temporal granularity

Existing energy system models use coarse spatial and temporal granularity and are not able to capture the variability in local energy systems and weather.

The options to decarbonise heat are likely to vary between different regions (UKERC, 2019a). These regions will likely have a localised energy system that utilises local energy supply resources and technologies to serve energy demands. These local energy supply systems will have an impact on the operation and planning of the national energy systems.

The increasing weather dependency of renewable energy supply requires models to capture the variability of weather over space and time. The spatial and temporal variability in weather needs to be modelled to avoid network congestions, curtailment of renewable energy and load shedding when operating at peak demand periods.

Modelling tools such as DECC 2050 and DynEMO do not consider spatial variations and only model a country as a single region. Whereas TIMES, DSIM and ESME include regional variations by splitting a country into different segments spatially.

The time resolution in planning models (CGEN+, MESSAGE) is typically coarse that use yearly timesteps excluding detailed variations of energy supply and demand seasonally and within a day. However, planning tools such as ESME and TIMES do allow the user to model intra-day time steps that signify peaks and shallows in energy supply and demand. In contrast, operational models such as DSIM and CGEN uses finer time resolution (hourly / minutely) to describe time variations in detail.

3.6.3. The trade-off between energy system complexity and computation requirements

Future energy supply systems will be complex due to the use of distributed energy supply and increasing interdependencies between electricity, natural gas, heat and hydrogen supply systems (CCC, 2019a). The existing modelling tools are limited in capturing these complexities due to the computational burden (Jalil-Vega and Hawkes, 2018).

The use of input-output models instead of energy network models as well as aggregation of time series and regions have been typically the simplifications used for dealing with the complexity of large energy system models.

Several studies (Hall and Buckley, 2016; Lopion et al., 2018; Pfenninger et al., 2018) discuss that the energy system models need to be flexible to allow the user to control the simplifications depending on the research question. Otherwise, the researchers would need to use high-performance computation facilities such as DAFNI (Data and Analytics Facility for National Infrastructure) (STFC et al., 2019) to perform analysis with complex energy system models

3.7. Summary

A review of modelling integrated energy systems was performed. Network-based and energy hub modelling were identified and discussed as the two key approaches of modelling and simulating integrated energy systems under steady-state. Optimisation of integrated energy systems under network and energy hub-based constraints were then discussed. A literature review of different analysis that employs simulation and optimisation of integrated energy systems was conducted. These studies were discussed by broadly categorising into operational and planning of integrated energy systems.

The review was then extended to existing tools for modelling integrated energy systems that have been used by the industry, academia, government departments and utility companies. The differences between these tools were investigated under key parameters such as purpose of the tool, modelling approach, sectoral coverage, geographical coverage, energy system representation, temporal coverage, methodology and mathematical approach. This comparison was used to identify limitations and research gaps of existing tools such as how models treat uncertainty, accessibility and transparency of data sets involved, coarse spatial and temporal granularity, and the trade-offs between model complexity and computation requirement.

The research presented in this thesis aims to address the limitation of coarse spatial and temporal granularity when representing integrated energy systems at both national and local scale. The modelling methodology was chosen such that it represents complex interactions between electricity, natural gas, and heating supply systems across different spatial scales avoiding exhaustive computational burden. Also, the user has given more control to deal with model complexities. Upon completion of this PhD research, the model and data sets will be publicly available under an open-source licence.

4. Development of the Combined Gas and Electricity Network Model (CGEN)

4.1. Introduction

National scale energy supply systems in many countries are composed of mainly electricity and natural gas transmission networks with interconnections allowing exports and imports beyond the national boundary. The operation of gas and electricity transmission networks are usually integrated via large natural gas-fired electricity generation. Also, there are natural gas compressor stations that are driven by electricity.

The Combined Gas and Electricity Network model - CGEN (Chaudry et al., 2008) investigates the combined operation of natural gas and electricity transmission networks of GB. The model has been applied to investigate a wide range of aspects in combined gas and electricity networks such as,

- impacts of large penetration of wind generation into the GB power system (Qadrdan, 2012b; Qadrdan et al., 2010a)
- GB energy system response to gas supply infrastructure failures (Chaudry et al., 2012)
- impacts of a low carbon power system to the GB gas network (Qadrdan et al., 2015b)
- use of power to gas options to reduce wind curtailment and combined operating costs of the networks (Qadrdan et al., 2015a)
- the efficacy of flexible gas-fired plants, electricity storage and power-to-gas systems to balance the electricity supply/demand (Qadrdan et al., 2017a)
- expansion planning of combined electricity and natural gas transmission networks (Chaudry et al., 2014a)

This chapter first describes in Section 3.2 the established CGEN model, as received at the start of this PhD project. Subsequent sections describe the developments made to the CGEN model during the PhD project. These were to,

Section 4.3 –

- expand the spatial representation of the natural gas and electricity transmission networks to allow the integration of energy distribution system representations.

Section 4.4 –

- model electricity interconnector bi-directional flows.
- improve the modelling of variable renewable generation to include weather parameters that are derived by climate change projections and consider the spatial variability of wind speed and solar irradiance.

Section 4.5 –

- characterise natural gas supply resources (imports, shale gas, UKCS) and impose supply constraints to the operation of the GB gas transmission network.

4.2. Established Combined Gas and Electricity Network model (CGEN)

The Combined Gas and Electricity Network (CGEN) model is an optimisation tool that models the operation of gas and electricity transmission networks in Great Britain as an integrated system. The objective of the CGEN model is to provide operational analysis considering the interdependencies between natural gas and electricity transmission networks.

The CGEN model is built within a multi-time period optimisation framework which minimises the total cost of operating the integrated system over a given time horizon. The time horizon and the operational timestep granularity are user-defined. The total cost is derived from the costs associated with electricity generation, gas resources supply, gas storage operation, gas line-pack management and unserved electricity and gas demand.

The electricity system operation is represented using a detailed DC load flow model and natural gas systems operation by a detailed gas flow model. The constraints for the optimisation describe the operational characteristics of the networks, their assets and equations from the DC load flow and gas flow formulations. The natural gas supply from different supply sources to consumers – industrial consumers, power stations and distribution gas supply points via high-pressure transmission pipeline network are modelled in CGEN. Natural gas reception terminals, storage facilities and compressor stations are modelled as assets. The operation of centralised power generators and power supply via high voltage transmission lines are modelled in the electricity network. Large natural gas-fired generators in the electricity transmission network are linked with the power station gas supply points in the natural gas transmission network. Various elements that are combined to form the CGEN model are shown in Figure 4.1.

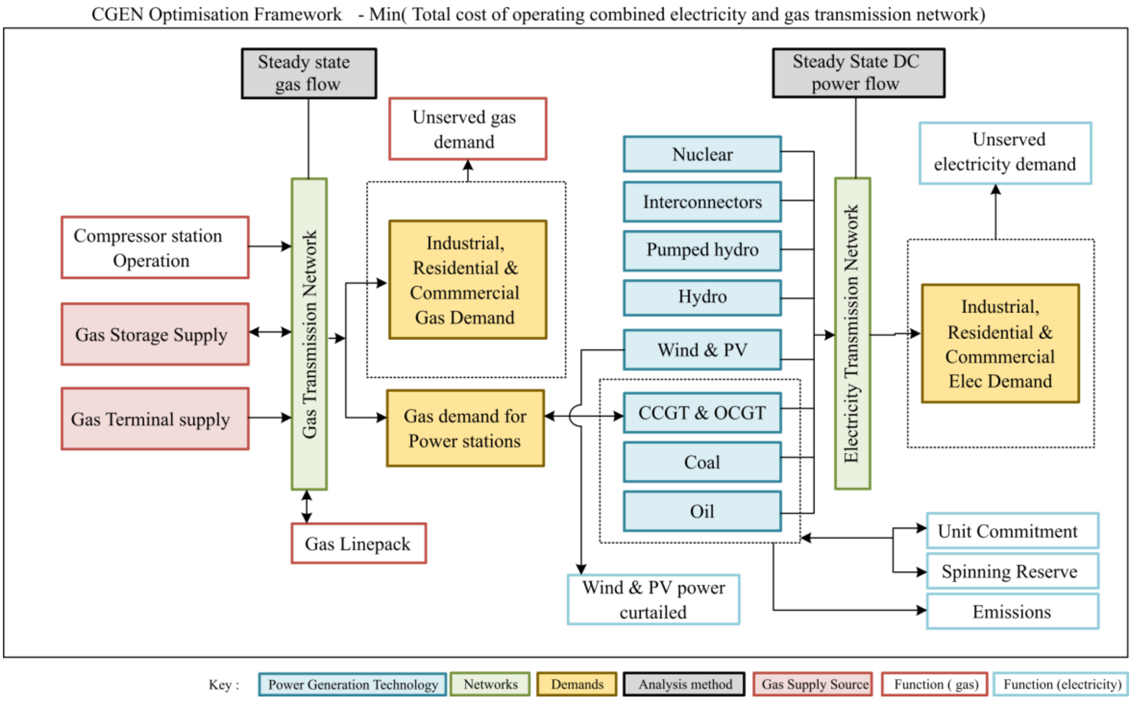

Figure 4.1 – An outline of the CGEN model

The optimisation problem of the CGEN model is formulated and solved using the Fico Xpress commercial optimisation suite. The Xpress-SLP (Sequential Linear Programming) solver for non-linear programming is used to minimise the objective function over the entire time horizon.

4.2.1. The objective function

The objective of the combined gas and electricity network is to minimise the combined operational costs whilst meeting demand requirements over the entire time horizon. The objective function is presented in Equation 4.1.

Objective =

$$min \sum_{t} \left\{ \begin{array}{l} \underbrace{\sum_{a} C_{a,t}^{gas} Q_{a,t}^{sup}}_{\text{Cost of gas supply}} + \underbrace{\sum_{u} C_{u}^{w} Q_{u,t}^{w} + \sum_{u} C_{u}^{I} Q_{u,t}^{I}}_{\text{Cost of gas storage withdraw \& injection}} + \underbrace{\sum_{m} C_{t}^{gas,sp} \partial LP_{m,t}}_{\text{Cost of change in linepack}} \\ + \underbrace{\sum_{k} C_{k}^{gen} P_{k,t}}_{\text{Cost of power generation}} + \underbrace{\sum_{n} C^{ug} Q_{n,t}^{ug}}_{\text{Cost of unserved gas demand}} + \underbrace{\sum_{b} C^{ue} P_{b,t}^{ue}}_{\text{Cost of unserved electricity demand}} \end{array} \right\} \quad (4.1)$$

The total cost for a time step t is derived as follows.

- The cost of gas supply at terminal a and time t is calculated by the volume of gas supply $Q_{a,t}^{sup}$ and gas price $C_{a,t}^{gas}$.

- The cost of operating a gas storage facility u is calculated by the gas volume injected $Q_{u,t}^{i}$ or withdrawn $Q_{u,t}^{w}$ and cost of gas withdrawal C_{u}^{w} or injection C_{u}^{i}.
- The cost of change in gas linepack $\partial LP_{m,t}$ of pipe m at time t is calculated using the spot gas price $C_{t}^{gas,sp}$ at time t.
- Power generation costs C_{k}^{gen} include fuel costs, operational and maintenance costs of a power generator k for generating a unit of electricity. This unit cost is used to calculate the costs of producing power $P_{k,t}$.
- The cost of unserved electricity demand is calculated using the unserved electricity demand $P_{b,t}^{ue}$ at electricity busbar b at time t with a high penalty cost C^{ue}. Similarly, at gas node n, the penalty cost C^{ug} is imposed on unserved gas demand $Q_{n,t}^{ug}$ at time t.

The decision variables in the objective function are subjected to constraints that are based on the operational characteristics of the networks and assets. The constraints from the natural gas network operation are described in Section 4.2.3. Electricity transmission network constraints are described in Section 4.2.4.

4.2.2. Electricity and natural gas network representations

The electricity and gas transmission network representations used in the established CGEN model are shown in Figure 4.2. The natural gas network represents the key operational assets in the network such as gas reception terminals, storage facilities and compressor stations and the electricity transmission network represents 16 GB regions (Chaudry et al., 2008).

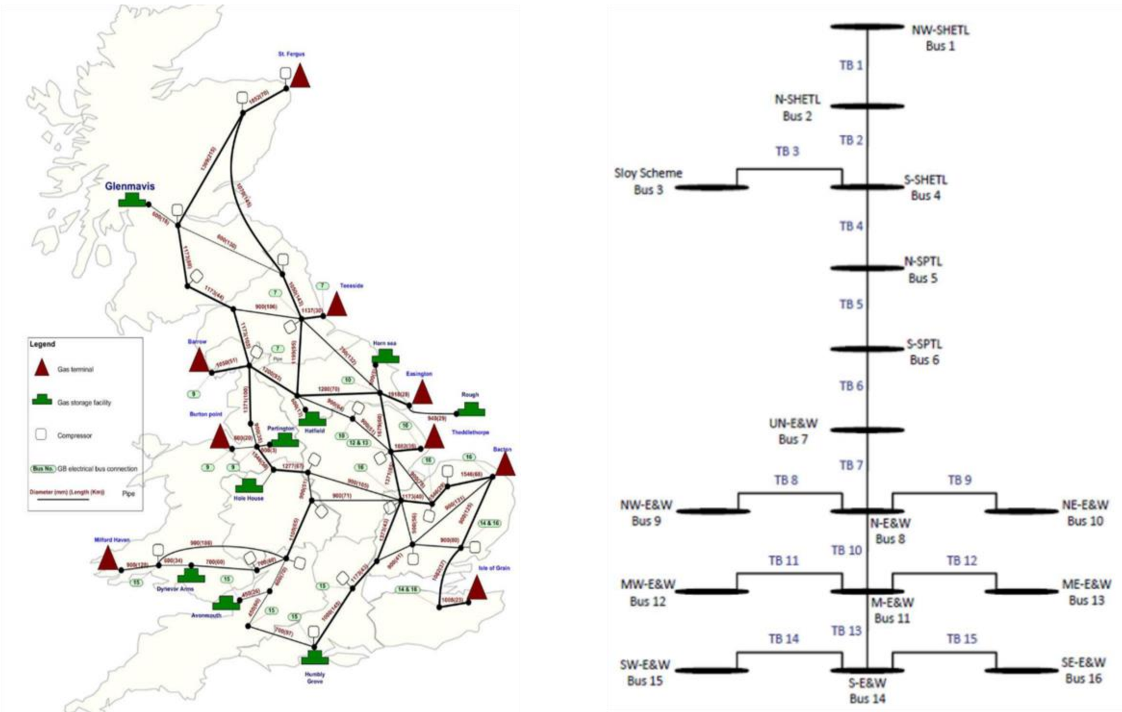

Figure 4.2 – GB gas (left) and electricity (right) transmission network representations in the established CGEN model.

4.2.3. Operating functions of the natural gas transmission network

The operating functions of the natural gas transmission network ensure the steady-state balance of gas supply and demand at each time step. Each node in the gas network is subjected to a steady-state gas flow balance shown in Equation 4.2. At each node n, at each time step t, gas inflows (gas supply from terminal a: $Q_{a,t}^{sup}$, gas storage withdrawal from storage facility u: $Q_{u,t}^{w}$, gas flows into compressor c: $Q_{c,t}$ and gas flow through pipe m into the node: $Q_{m,t}$) are balanced with gas outflows (storage injection at facility u: $Q_{u,t}^{I}$, gas demand $Q_{n,d,t}$, compressor c fuel consumption $\tau_{c,t}$ and pipe flows from the node). The network topology is used to generate node-asset incidence matrices M which create connections between the node (n) and assets such as pipes (m), terminals (a), compressor stations (c) and storage facilities (u). The unserved gas demand is given by $Q_{n,d,t}^{ug}$.

$$M_{n,m}Q_{m,t} + M_{n,a}Q_{a,t}^{sup} + M_{n,c}Q_{c,t} - M_{n,\tau c}\tau_{c,t} + M_{n,u}\left(Q_{u,t}^{w} - Q_{u,t}^{I}\right) = M_{n,d}\left(Q_{n,d,t} - Q_{n,d,t}^{ug}\right) \quad (4.2)$$

Here, $M_{n,m}$ is the node-pipe incidence matrix, $M_{n,a}$ is the node-terminal incidence matrix, $M_{n,c}$ is the node-compressor incidence matrix, $M_{n,\tau c}$ is the node-gas fuelled compressor incidence matrix, $M_{n,u}$ is the node-storage incidence matrix, and $M_{n,d}$ is the node-demand (offtakes) incidence matrix.

The steady-state relationship between upstream/downstream nodal pressures $p_{1,t}$, $p_{2,t}$ and average gas flow through a pipe m at time t, $Q_{m,t}^{av}$ is described in Equation 4.3. A detailed derivation of Equation 4.3 is presented in (Qadrdan, 2012b).

$$\frac{p_{1,t} - p_{2,t}}{L_m} = -\frac{2\,Z\,R\,T^{av}\,f\,(\rho)^2\,\left(Q_{m,t}^{av}\right)\left|Q_{m,t}^{av}\right|}{A_m^2 D_m\, p_t^{av}} \quad (4.3)$$

The subscripts $1, 2$ refer to the upstream and downstream nodes of pipe m. Here, pipe dimensions are given as length L_m, cross-sectional area A_m and diameter D_m. Equation 4.2 includes average gas pressure p_t^{av}, and temperature T^{av} alongside gas compressibility factor Z, gas constant R, pipe friction f, and natural gas density ρ.

In network operation, the pressure of node n at time t, $p_{n,t}$ is constrained between the maximum and minimum operating pressures as described in Equation 4.4.

$$p_n^{min} \leq p_{n,t} \leq p_n^{max} \quad (4.4)$$

The additional functions for compressor station and storage facility operation are derived in the following sections.

a. Linepack modelling

Typically, natural gas takes hours to reach its intended destinations (demand points) from a distant reception terminal or a storage facility. Therefore, an additional volume of gas is stored within the transmission pipes under high pressure. This volume of gas stored within the pipes is called linepack. Linepack is a key factor in gas network operation to meet sudden fluctuations in demand locally, rather than depending on distant sources.

Under steady-state conditions, Equation 4.5 gives the volume of gas stored in a pipe m, V_m^n. This illustrates that the linepack is proportional to the average pressure along the pipe $p_{m,t}^{av}$. Therefore, increasing the average pressure along with the pipe results in increasing the linepack.

$$LP_{m,t} = V_m^n = \frac{p_{m,t}^{av}\ V_m}{\rho^n\ Z\ \ R\,T^n} \tag{4.5}$$

Here, V_m is the volume of the pipe, ρ is the density of natural gas, Z is the compressibility factor, R is the gas constant, and T is the temperature. Superscript n denotes standard conditions.

However, in dynamic situations, the gas flow into and out of a pipe fluctuates according to the changes in supply and demand. According to the law of conservation of mass, the difference between the flow in and out of a pipe is equal to the change of total gas volume. Thus, Equation 4.5 is altered to Equation 4.6 to calculate the linepack at time t:

$$LP_{m,t} = LP_{m,t-1} + \int_{t-1}^{t} \left(Q_{m,t-1}^{n,in} - Q_{m,t-1}^{n,out}\right)\ dt \tag{4.6}$$

where the initial gas volume stored in the pipe $LP_{m,0}$ satisfies Equation 4.5 in the steady-state condition, and superscripts *in* and *out* refer to gas flows in and out of the pipe.

b. Gas Compressor modelling

Gas compression is performed to compensate for pressure and energy losses due to the friction along the transmission and distribution pipelines. Gas compression by compressors facilitates the supply of gas with the required pressure for downstream consumers. Gas compressor stations are installed at regular intervals within the transmission network to perform gas compression.

The power required from the compressor prime mover at time t is calculated by Equation 4.7 (Osiadacz, 1987):

$$P_{c,t} = \frac{Q_{c,t}^{n}\ \alpha}{\eta_c(\alpha - 1)} \left[\left(\frac{p_{c,t}^{out}}{p_{c,t}^{in}} \right)^{(\alpha-1)/\alpha} - \ 1 \right] \tag{4.7}$$

where $P_{c,t}$ is the power required to drive the compressor c, $Q_{c,t}^n$ is the gas flow through the compressor at standard conditions, α is a Polytropic exponent, η_c is the compressor efficiency, $p_{c,t}^{out}$ is the pressure of gas discharged from the compressor, and $p_{c,t}^{in}$ is the pressure of gas into the compressor.

The performance of the compressor is restricted by the maximum pressure ratio (Equation 4.8), maximum flow through the compressor (Equation 4.9) and the maximum power required by the prime mover (Equation 4.10).

$$1 \leq \left(\frac{p_{c,t}^{out}}{p_{c,t}^{in}}\right) \leq \left(\frac{p^{out}}{p^{in}}\right)_c^{max} \tag{4.8}$$

$$Q_{c,t}^{n} \leq Q_c^{n,max} \tag{4.9}$$

$$P_{c,t} \leq P_c^{max} \tag{4.10}$$

A fraction of the natural gas flow through the compressor is used as fuel by the compressor prime movers such as reciprocating engines and gas turbines. Linear estimation of the amount of gas trapped by the prime movers is given by Equation 4.11 (An et al., 2003):

$$\tau_{c,t} = \beta\, P_{c,t} \tag{4.11}$$

where $\tau_{c,t}$ is the amount of gas trapped by the compressor, and β is the linear fuel rate coefficient of the prime mover of a compressor.

c. Gas storage facilities modelling

Gas storage facilities act as a balancing tool for matching the gas supply and demand within the transmission network. There are short-term and long-term storage facilities within the network to provide balancing daily and seasonally. Over short-term operation, natural gas is withdrawn from and injected into the storage facility according to the daily variations in gas prices and demand. Natural gas is injected into the seasonal gas storage facilities during summer periods and gas is withdrawn from the storage facilities during winter to meet high demands.

The key operational parameters of a storage facility are the working gas volume and the rate at which gas is withdrawn and injected. Working gas volume ($S_{u,t}^{work}$) referrers to the volume of gas that can be withdrawn from the storage facility. The total gas volume of the storage facility (S_u^{max}) is a summation of the working gas and cushion gas volumes $\left(S_u^{cush}\right)$. Cushion gas is the volume of gas required in storage to maintain adequate pressure and is not typically available to be withdrawn. Therefore, the working gas volume is constrained as given in Equation 4.12.

$$S_u^{cush} + S_{u,t}^{work} \leq S_u^{max} \tag{4.12}$$

The working gas volume at each time step is calculated based on the gas withdrawal flow rate $\left(Q_{u,t}^{w}\right)$ from or injected flow rate $\left(Q_{u,t}^{w}\right)$ into the storage facility.

$$S_{u,t}^{work} = S_{u,t-1}^{work} - Q_{u,t}^{w} + Q_{u,t}^{i} \tag{4.13}$$

The gas injection and withdraw flow rates are constrained through Equations 4.14 and 4.15, respectively.

$$0 < Q_{u,t}^{i} \leq Q_{u,t}^{i,max} \tag{4.14}$$

$$0 < Q_{u,t}^{w} \leq Q_{u,t}^{w,max} \tag{4.15}$$

Here, $Q_{u,t}^{w,max}$ and $Q_{u,t}^{i,max}$ are characterised by the working gas volume and cushion gas volume at time t. In gas withdrawal, the withdrawal flow rate is highest when a storage facility is close to its maximum capacity and lowest when nearly empty (Thompson et al., 2009):

$$Q_{u,t}^{w,max} = K_u \sqrt{S_{u,t}^{work}} \tag{4.16}$$

Considering that the physical maximum delivery rate/flow rate occurs when the storage facility is at maximum gas capacity S_u^{max}, the constant K_u can be calculated using Equation 4.16.

The injection flow rate is at its lowest (close to zero) when a storage facility is at maximum capacity and at its highest when the storage facility is empty. As given by (Thompson et al., 2009), the maximum injection flow rate is,

$$Q_{u,t}^{i,max} = K'_u \sqrt{\frac{1}{S_{u,t}^{work} + S_{u,t}^{cush}} + K''_u} \tag{4.17}$$

No more gas injection takes place $\left(Q_{u,t}^{i,max} = 0\right)$ when the gas storage facility is at its maximum capacity. Hence, using the known values for $S_{u,t}^{work}$ and $S_{u,t}^{cush}$, K''_u from Equation 4.17 can be calculated. The maximum injection flow rate occurs when $S_{u,t}^{work} = 0$, therefore K'_u from Equation 4.17 can be calculated.

4.2.4. Operating functions of the electricity transmission network

Electricity generated at centralised large power stations is transmitted to grid supply points via high voltage (400kV-132kV) transmission lines. The electricity transmission network operation is represented by a steady-state DC power flow model (McDonald and Wang, 1994; Wood and Wollenberg, 1996). This is a simplification of an AC power flow based on the following assumptions,

- The line resistance in a high voltage transmission system is very much smaller when compared to line reactance, such that resistance and system losses can be neglected.
- The phase voltage angle difference of a high voltage line is very small.
- The bus voltage per unit is close to the nominal value (~1.0 p.u.).

The DC power flow formulation enables the calculation of MW power generated at each busbar and power flows in each transmission line. The total electricity generation in the system is balanced with the total demand (considering unserved demand) at each time step t, Equation 4.18.

$$\sum_{k} P_{k,t} = \sum_{b} P_{b,d,t} - \sum_{b} P_{b,d,t}^{ue} \tag{4.18}$$

Where $P_{k,t}$ is the power output of generator k at time t, $P_{b,d,t}$ is total electrical power demand at busbar b and time t, and $P_{d,t}^{ue}$ is unserved electricity at busbar b and time t.

The maximum power transmission capacity of a line P_l^{max} constrains the power flow along a line at a given timestep t, $P_{l,t}$.

$$P_{l,t} \leq P_l^{max} \tag{4.19}$$

a. Power generation

Equation 4.20 describes that the power generated from a plant is kept within the physical limitations of generation units.

$$P_k^{min} \leq P_{k,t} \leq P_k^{max} \tag{4.20}$$

b. Ramp rate constraints

Power generators cannot be ramped up or down instantaneously. The power ramp-up (Equation 4.21) or ramp down (Equation 4.22) needs to be kept within the physical limitations of generation units.

$$P_{k,t} - P_{k,t-1} \leq RU_k \tag{4.21}$$

$$P_{k,t-1} - P_{k,t} \leq RD_k \tag{4.22}$$

Here, RD and RU are ramp-down and ramp-up limits for generator k.

c. Minimum up and downtime

When a thermal power generator is started up or shut down, it remains so for a minimum uptime and downtime period. The constraints for this minimum duration of uptime and downtime of thermal power stations are implemented using (Gröwe-Kuska et al., 2002) and shown in Equations 4.23 and 4.24.

$$\gamma_{k,t'} - \gamma_{k,t'-1} \leq \gamma_{k,t}\,, \qquad t' = [t - MUT_k + 1, t - 1] \tag{4.23}$$

$$\gamma_{k,t'-1} - \gamma_{k,t'} \leq 1 - \gamma_{k,t}\,, \qquad t' = [t - MDT_k + 1, t - 1] \tag{4.24}$$

Here, $\gamma_{k,t}$ is the binary variable which relates the on/off state of thermal power station k, MUT_k is minimum uptime and MDT_k is the minimum downtime.

d. Spinning reserve

A spinning reserve is kept in the power system to be dispatched within a short interval of time to control the frequency and to maintain the balance between power demand and supply. The spinning reserve is usually equal to the unused capacity of synchronised generators which can be dispatched immediately by the system operator.

A secure power system operation requires maintaining a minimum level of spinning reserve $\underline{r}$. It is typically equal to the capacity of the largest generator, or a certain percentage of the peak load. An additional reserve is kept such that the power system can operate under uncertainty of wind and solar PV generation. This is modelled as shown in Equation 4.25, where the additional reserve requirement is equal to a $r\omega$ percentage of total wind and PV generation at a given time t.

$$r_t = \sum_k r_{k,t} \geq \underline{r} + r\omega \times \left(\sum_i^{\{wind,PV\}} P_{i,t} \right) \tag{4.25}$$

The reserve available in a thermal generator k at time t is determined by the power output $P_{k,t}$ and the maximum power generation limit P_k^{max} as shown in Equation 4.26. Here, $\gamma_{k,t}$ is the variable for the on/off state of the generator.

$$r_{k,t} = \gamma_{k,t} \left(P_k^{max} - P_{k,t} \right) \tag{4.26}$$

e. Pumped storage systems modelling

Pumped storage systems are used in balancing electricity supply and demand in the system. When there is low-cost surplus electricity (typically from renewable generators), it is used to pump water from a lower elevation reservoir to a higher elevation reservoir. During high demand periods, the water is released from the high elevation reservoir, and electricity is produced from hydro turbines.

The behaviour of the pumped hydro storage is modelled by defining a storage level of equivalent electrical energy. At time t, the energy balance of the pumped storage unit ps is given as,

$$E_{ps,t} = E_{ps,t-1} + (\eta^{pump} \times P_{ps,t}^{pump} - P_{ps,t}) \times t \tag{4.27}$$

The electricity supplied to the system at time t, $P_{ps,t}$ is constrained by either the generation capacity P_{ps}^{max} or the stored energy level $E_{ps,t-1}$.

$$P_{ps,t} \times t \leq \min \left(P_{ps}^{max} \times t \ , E_{ps,t-1} \right) \tag{4.28}$$

Additionally, the storage level at time t ($E_{ps,t}$) is constrained by the maximum available storage capacity (E_{ps}^{max}), as given in Equation 4.29.

$$E_{ps,t} \leq E_{ps}^{max} \tag{4.29}$$

4.2.5. Coupling of natural gas and electricity transmission networks

The coupling between the electricity and natural gas transmission networks is through natural gas-fired generators. While the power output of these generators acts as a supply variable within the electricity system, the consumption of natural gas to produce power is imposed as demand for the natural gas transmission network. The two decision variables are linked by Equation 4.30.

$$P_{k,t} = \eta \times Q_{k,t} \times H_g \tag{4.30}$$

Here, the factor H_g is the heating value of natural gas taken as 39.6 MJ/m3 (National Grid, 2018a) and converts the gas consumption of the gas-fired generator k at time t, from *mcm (million cubic meters)* to *MWh.*

4.3. Improvements made to the spatial granularity of the CGEN model

The spatial granularity of the electricity and natural gas transmission network representations in the established CGEN model was improved to integrate local energy distribution systems. Also, the representative networks were developed in Geographic Information System (GIS) format. The increased granularity of the networks and GIS locations enabled the identification of gas nodes and electricity busbars that connect with the distribution networks in a geographic region. The following sections describe the process of improving the spatial granularity of the two transmission networks.

4.3.1. Natural gas transmission network

The natural gas transmission network was developed using the network maps published by the National Grid Ten Year Statement (National Grid, 2018a) and the GIS format data available (National Grid, 2018b). The GIS data of the natural gas transmission network and assets are shown in Figure 4.3(a). “Gas Sites” show the locations of gas terminals, gas compressor stations, gas offtakes and storage facilities.

The simplified network was then developed on top of the full network map, preserving the actual locations of gas offtakes and other assets. Simplifications were made to the nodes which are in a loop and parallel pipes to reduce the complexity. The simplification methodology was adopted from (Qadrdan et al., 2010b) and is presented below. Consequently, the full network (Figure 4.3a) was reduced to a simplified network with 80 nodes and 110 pipes (Figure 4.3b).

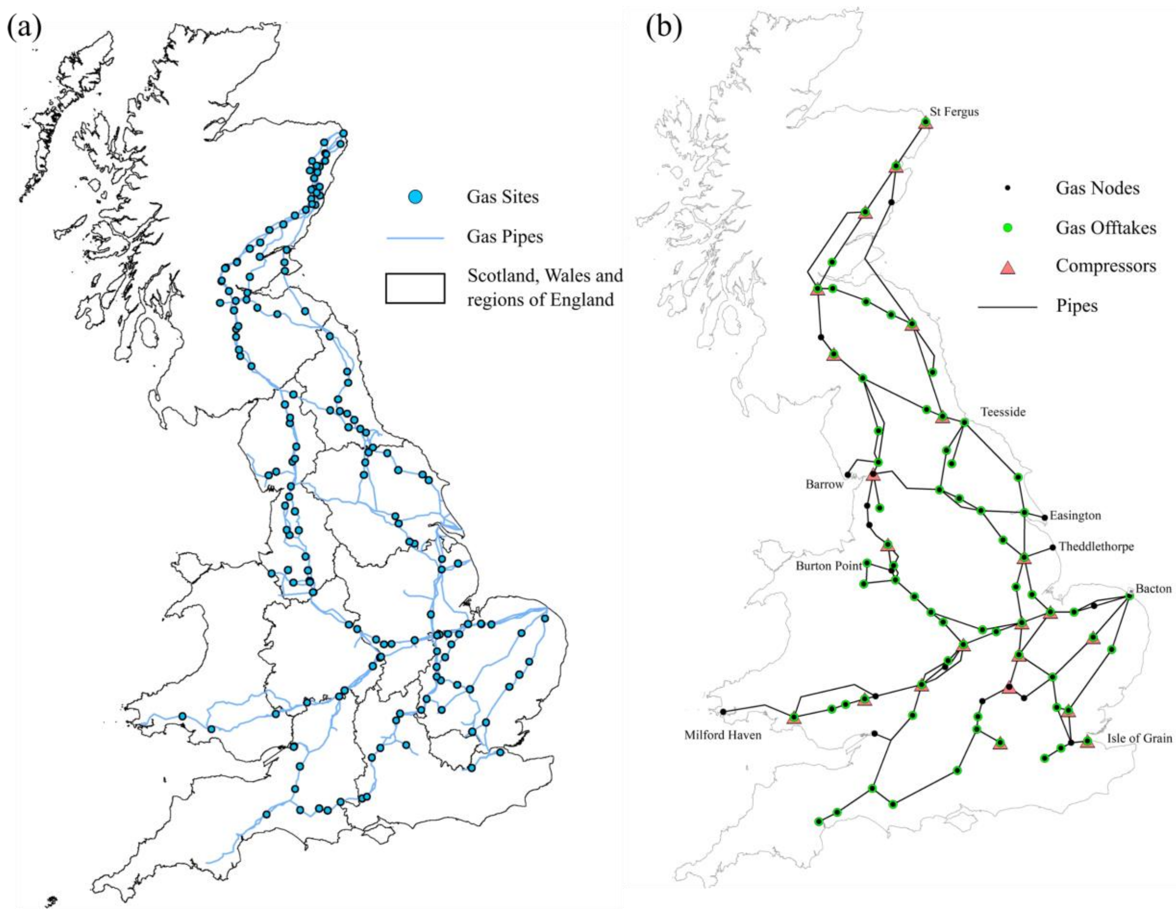

Figure 4.3 – The natural gas transmission network, (a) published data and (b) the simplified representative data.

a. Simplifying parallel pipes

Parallel pipes (pipes 1,2, and 3 in Figure 4.4a) were simplified into an equivalent single pipe (pipe AG in Figure 4.4b). The gas flow through this single pipe is the summation of gas flows in the parallel pipes having the same upstream and downstream pressure difference.

The gas flow equations for a parallel pipe (m) and the equivalent pipe (eq) is described in Equation 4.31 (Osiadacz, 1987). Here, pipe efficiency (E), base temperature and base pressure are assumed the same across all pipes and the equivalent pipe.

$$\Delta p_m = p_{m,A}^2 - p_{m,B}^2 = K_m Q_m^{1.854} \ , K_m = \frac{18.43 \times L_m}{E^2 \times D_m^{4.854}}$$

$$\Delta p_{eq} = p_{eq,A}^2 - p_{eq,B}^2 = K_{eq} Q_{eq}^{1.854} \ , K_{eq} = \frac{18.43 \times L_{eq}}{E^2 \times D_{eq}^{4.854}} \tag{4.31}$$

The gas flow through the equivalent pipe (Q_{eq}) is the summation of the gas flow through parallel pipes as given in Equation 4.32.

$$Q_{eq} = Q_1 + Q_2 + Q_3 \tag{4.32}$$

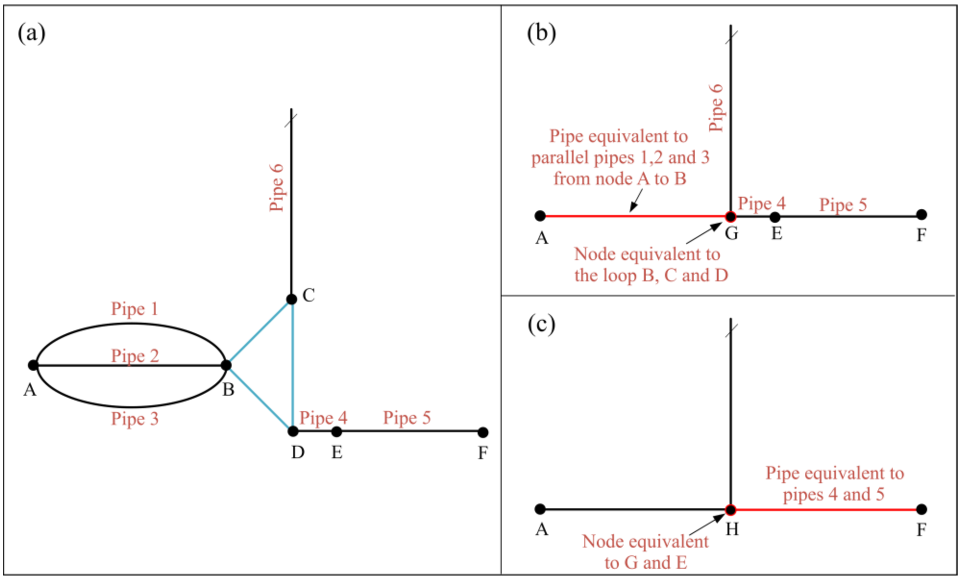

Figure 4.4 – An example of gas network simplification, (a) part of the original network, (b) simplified parallel pipes and loops, (c) simplified closed proximity nodes.

Most of the parallel pipes typically have almost equal lengths, thus the arithmetic average of pipe's length (Equation 4.33) is taken as the length of the equivalent pipe (L_{eq}). The diameter of the equivalent pipe (D_{eq}) is calculated by Equation 4.34 (Qadrdan et al., 2010b).

$$L_{eq} = \frac{L_1 + L_2 + L_3}{3} \tag{4.33}$$

$$D_{eq} = \sqrt[2.618]{D_1^{2.618} + D_2^{2.618} + D_3^{2.618}} \tag{4.34}$$

b. Equivalent nodes combining short pipe lengths and loops.

A loop of nodes (nodes B, C and D in Figure 4.4a) with short pipe lengths was substituted by an equivalent node (node G, in Figure 4.4b). The pipes connected across the loop were therefore now connected to the equivalent node.

The simplification process from Figure 4.4(b) to 4.4 (c) was made by replacing a short length pipe (Pipe 4) and its adjacent pipe (Pipe 5) with an equivalent pipe. Here, the upstream (E) and downstream nodes (G) of Pipe 4 were substituted by an equivalent node (H). The dimensions of the equivalent pipe were set to satisfy Equation 4.34.

$$\Delta p_{eq} = \Delta p_4 + \Delta p_5 \tag{4.35}$$

As the pipes are in a series, the gas flows through all pipes are the same. Hence,

$$Q_{eq} = Q_4 = Q_5 \tag{4.36}$$

The combination of Equation 4.35 and 4.36 yields,

$$K_{eq} = K_4 + K_5 \,; where\ K_i = \frac{18.43 \times L_i}{E^2 \times D_i^{4.854}} \tag{4.37}$$

The length of the equivalent pipe is taken as the arithmetic sum of the lengths of the pipes in series.

$$L_{eq} = L_4 + L_5 \tag{4.38}$$

The diameter of the equivalent pipe D_{eq} is then calculated by substituting L_{eq} from Equation 4.38 into Equation 4.37, and D_{eq} is given by,

$$D_{eq} = \sqrt[4.584]{L_{eq} \Big/ \left(\frac{L_4}{D_4^{4.584}} + \frac{L_4}{D_4^{4.584}} \right)} \tag{4.39}$$

4.3.2. Electricity transmission network

The 16-busbar electricity transmission network in the established CGEN model was improved into a 29-busbar network representation. The 29-busbar network was developed to follow actual 275kV/400kV grid substation locations across the actual electricity transmission network, compared to the representative regional busbars in the established CGEN model.

Initially, GIS format data was obtained from the three transmission asset owners in the UK; National Grid, Scottish and Southern Electricity (SSEN) and Scottish Power (SP). The complete electricity transmission network map in GIS format is shown in Figure 4.5(a). The data for the 29 busbar electricity network was adapted from (Bell and Tleis, 2010) and transformed into the CGEN model using the ArcGIS software. In this process, a GIS power station map (Carbon Brief, 2016a) shown in Figure 4.5(b) was used to assign the power generators to each busbar using their actual locations. The power station data was cross-checked with the published data (Bell and Tleis, 2010; DUKES, 2016).

The 29-busbar electricity transmission network is shown in Figure 4.5(c).

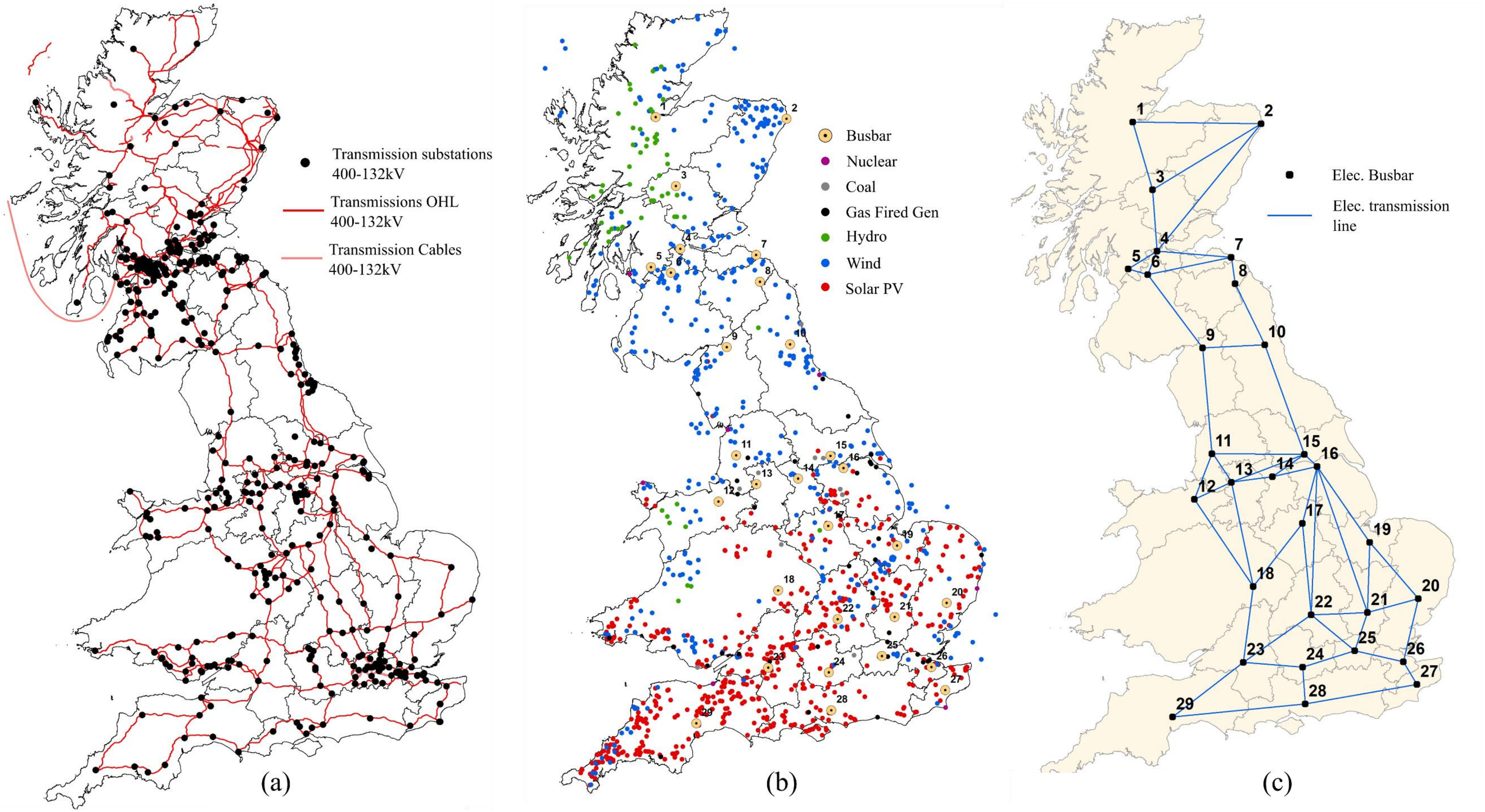

Figure 4.5 – (a) The collected electricity transmission network data, (b) Power stations data adopted from (Carbon Brief, 2016a)*, and (c) representative 29 busbar electricity transmission network*

4.4. Improvements made to the operational functions of the electricity transmission network

Improvements were made to electricity interconnector and wind/PV generation modelling of the established CGEN model. These were to,

- model bi-directional interconnector flows (4.4.1)
- model wind and PV generation considering (4.4.2),
  - spatial variability of weather parameters; wind speed and solar irradiance
  - weather parameters derived from climate change for future years

4.4.1. Bi-directional electricity interconnector flows

The GB power system over the next few decades is projected to be highly interconnected to France, Belgium, Netherlands and Norway. In future scenarios, it is projected to have net exports due to a large amount of excess electricity generated from offshore wind farms (National Grid, 2019a). Hence, bi-directional interconnector flow is becoming an important aspect of the analysis of future power systems.

The established methodology in the CGEN model treats interconnectors as generators. Here, for an interconnector i, the import power at given time t is taken as $P_{i,t}^{imp}$. The interconnector flows are therefore assumed unidirectional.

An additional variable was introduced for the power export ($P_{i,t}^{exp}$) through an interconnector i at a given time t. The interconnector flows were then assigned to be bi-directional, and "energy neutral" (Equation 4.40) over the operating time horizon (T). The "energy-neutral" constraint was used to ensure that the total energy production and consumption in the UK over the operating time horizon (T) is fully balanced (Strbac et al., 2016). An additional advantage of using the "energy-neutral" concept was that this avoided the use of binary variables to set the direction of interconnector flows.

$$\sum_{t}^{T} \sum_{i}^{Interconnectors} P_{i,t}^{imp} = \sum_{t}^{T} \sum_{i}^{Interconnectors} P_{i,t}^{exp} \tag{4.40}$$

Both export and import flows were subjected to the max interconnector flow capacity.

$$P_{i,t}^{imp}, P_{i,t}^{exp} \leq P_{i}^{max} \tag{4.41}$$

The cost of importing electricity by an interconnector i was set to determined by the average wholesale electricity price of the connected country. The country connected and annual price data were set as new inputs to the CGEN model as shown in Table 4.1. The new total cost of interconnector operation C^{int} as described in Equation 4.42 was added to the objective function of the CGEN model. The total cost of the interconnector operation describes the cost of importing electricity $\left(P_{i,t}^{imp}\right)$ at an import cost of C_i^{imp}, and revenues of exporting electricity $\left(P_{i,t}^{exp}\right)$ for a spot electricity price of $C_t^{elec,sp}$.

$$C^{int} = \sum_{t}^{T} \sum_{i}^{Interconnectors} \left(P_{i,t}^{imp} \times C_i^{imp} - P_{i,t}^{exp} \times C_t^{elec,sp} \right) \tag{4.42}$$

Table 4.1 – Operational GB interconnectors, their capacities, and an annual average price of imported electricity via each interconnector link in 2015.

Interconnector (i)	Capacity – MW, P_i^{max}	C_i^{imp} – Annual average price (imports) in 2015 (£/MWh) (Trichakis and Humphry, 2014)
GB – France	2000	42
GB – Northern Ireland (IR)	500	35
GB – Netherlands	1000	40
GB – Ireland	500	60

4.4.2. Wind and PV power generation

The established CGEN model used one wind and PV generation profile for the whole GB and is an input to the model. This methodology was changed to use weather parameters, wind speed and solar irradiance as inputs to the model. Using these inputs, the power output from wind and PV plants were calculated within the model. Additionally, spatial variability of wind speed and solar irradiance was accounted for by using the GIS implementation of the representative GB electricity network. A separate weather module was implemented to extract data from data sources (e.g. Met Office data) and convert them into the format required by the model.

a. <u>Weather Data</u>

"Weather@Home" (Guilod et al., 2017) data set was used to obtain forward projections of wind speed, solar irradiance and temperature. This dataset was developed within the MaRIUS (Managing the Risks, Impacts and Uncertainties of droughts and water Scarcity project, funded by the UK Natural Environmental Research Council and lead by the University of Oxford and in partnership with the UK Met Office. The data for these parameters are available in a **daily** time granularity for a historic baseline (1900-2006) and future years (2020 to 2050) across numerous climate change scenarios (~100 realisations). The historic baseline data has been validated (Guillod et al., 2018, 2017) and future projections were shown in line with UK Climate Projections 2009 (Met Office, 2009). A 10km x 10 km grid is available across GB providing weather parameters at each gird point as shown in Figure 4.6(a).

b. Weather data points mapping with the representative electricity network

The GIS data of the electricity busbar locations was used to get the closest weather data point from the *Weather@Home* data grid. A near feature analysis[3] was performed using the ArcGIS software, with a 10km proximity to select the closest point from the input electricity busbar data set to the weather data points. The result of this analysis is shown in Figure 4.6(b).

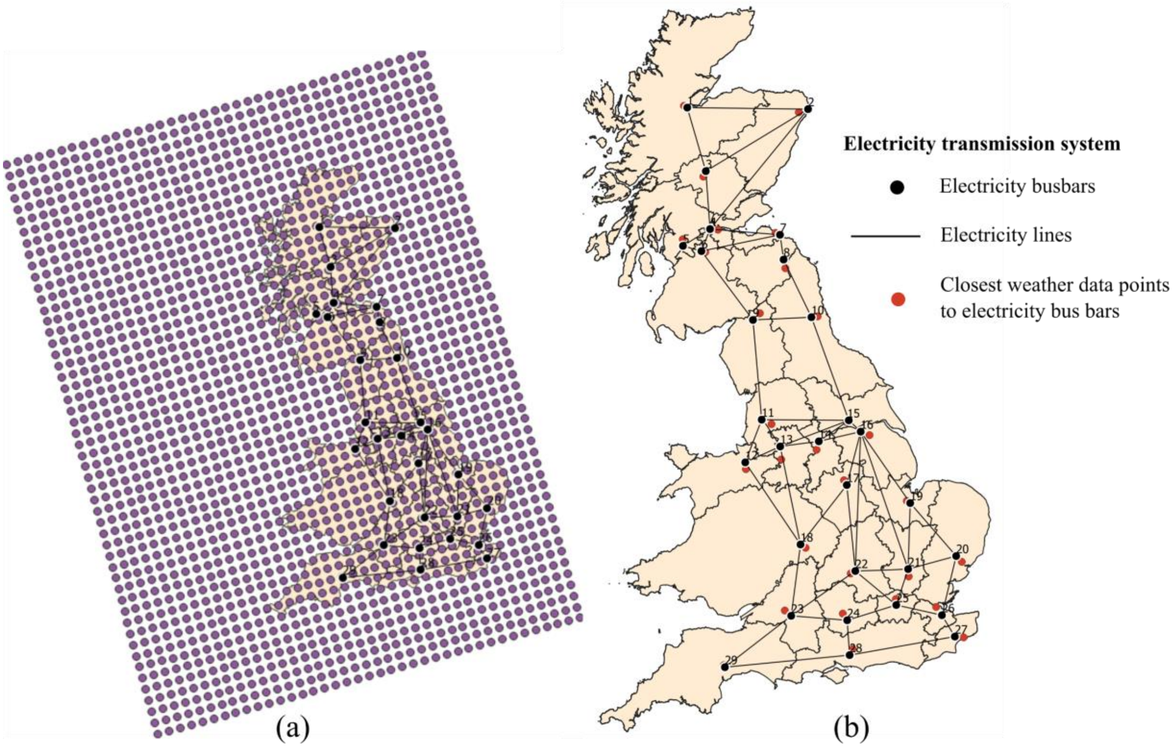

Figure 4.6 – (a) GB weather data points available in Weather@Home data set and (b) representative weather data points for the electricity transmission network

Wind speed and solar irradiance data from the Weather@Home data set were then extracted for the selected closest weather data point.

c. Data conversions and Weather Module

The Weather@Home data for future years are available as a mean value for each day of the year. A weather module was implemented to extract this data for the given electricity transmission network busbars and convert daily weather data into an hourly time granularity. For this purpose, historical weather data from the Met Office data archive was used (Met Office, 2016).

The hourly historic weather patterns (e.g. for the year 2010) were initially normalised using daily means. Then the data for the desired future year (e.g. 2025) was overlaid on the normalised weather pattern to generate hourly weather data. This process was performed for both wind speed and solar irradiance. The

[3] A feature in geoprocessing tools (e.g. ArcGIS, QGIS) to calculate the straight-line distance from one set of features (electricity busbars) to another (weather data points) which is within a specified proximity radius (10km). From the outputs, the feature with the shortest distance is selected.

weather module was designed such that the historic year and the forward climate projection (weather scenario) to be user-defined. This is referred to within the simulations as a scenario of future years from the *Weather@Home* dataset based on hourly patterns of a historical year.

The overall conversion processes are shown in Figure 4.7.

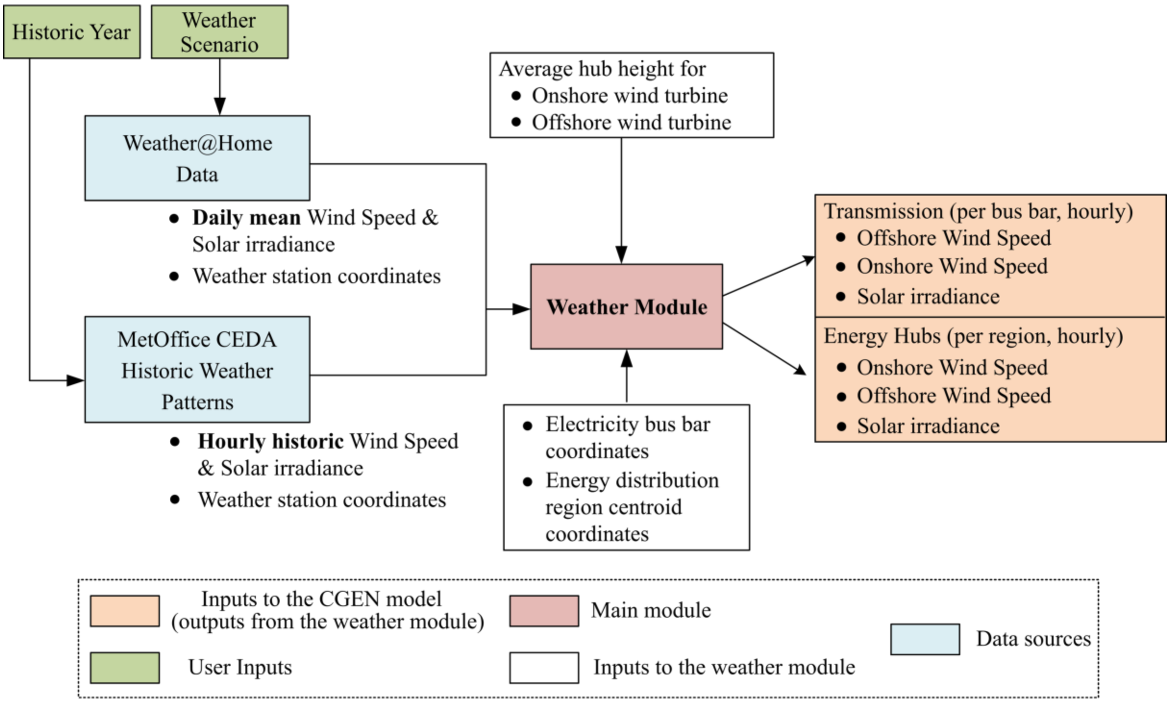

Figure 4.7 – Overview of the implemented weather module – data sources, inputs and conversions

The wind speed data were differentiated for offshore and onshore wind generation by converting the available wind speed data ($h^{measure}$, 10m above ground), using an average hub height (h^{av}) for offshore (125m) and onshore (90m) wind turbines using Equation 4.43 (Khaligh and Onar, 2009). The hub heights were obtained from commercial product catalogues by wind turbine manufacturers (Siemens, 2018; Vestas, 2017) for onshore and offshore wind applications.

$$v_t = v_t^{measure} \left(\frac{h^{av}}{h^{measure}} \right)^{\frac{1}{7}} \tag{4.43}$$

d. Calculating power generation from a wind turbine

A typical wind speed to power output curve was used (specifying differently for offshore and onshore installations) to calculate the power output from a wind turbine accounting for cut-in, rated and cut-off wind speeds as shown in Figure 4.8.

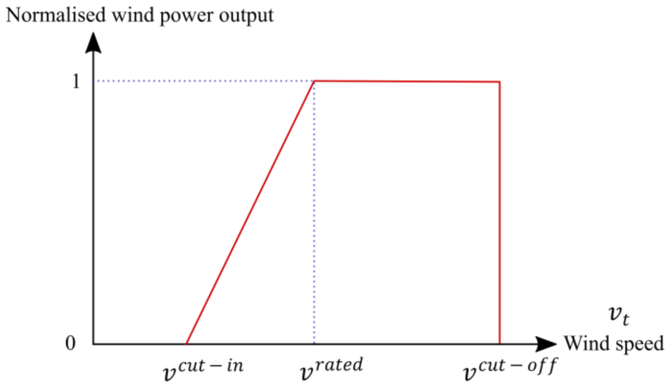

Figure 4.8 – A normalised typical power output vs. wind speed curve of a wind turbine

Given the wind speed v_t , the power output $P_{k,t}$ from a wind turbine k with a rated capacity P_k^{rated} is calculated using Equation 4.44.

$$P_{k,t} = \begin{cases} 0;\ if\ v_t \leq v^{cut-in}\ or\ v_t \geq v^{cut-off} \\ \left(\dfrac{v_t - v^{cut-in}}{v^{rated} - v^{cut-in}}\right) P_k^{rated}\ ;\ if\ v^{cut-in} \leq v_t \leq v^{rated} \\ P_k^{rated}\ ;\ if\ v^{rated} \leq v_t \leq v^{cut-off} \end{cases} \tag{4.44}$$

The linear approximation between wind turbine power output and wind speeds v_t when $v^{cut-in} \leq v_t \leq v^{rated}$ provides an error. An error analysis for a 2MW wind turbine showed an ~33% over estimation is presented by the linear approximation. The analysis is given in Appendix D.

The typical values of $v^{cut-off}$, v^{cut-in} and v^{rated} for offshore and onshore wind applications are shown in Table 4.2. These values were obtained from the commercial product catalogues of wind turbine manufacturers (Siemens, 2018; Vestas, 2017).

Table 4.2 – Wind speed characteristics for onshore and offshore wind applications

Application	v^{cut-in} (ms^{-1})	$v^{cut-off}$ (ms^{-1})	v^{rated} (ms^{-1})
Offshore	5	20	11
Onshore	3	20	7

e. Calculating power generation from a PV array

The power output from a solar PV array was modelled using Equation 4.45, given hourly solar irradiance (I_t) as inputs from the weather module.

$$P_{k,t} = A_k \times \eta_k \times\ PR_k\ \times I_t \tag{4.45}$$

Here, η_k is the efficiency of the solar PV array k and PR_k is the performance ratio of the array which considers additional losses, e.g. losses due to high cell temperature. An average value of 0.7 for $PR_k$and 0.2 for η_k were used (Peake, 2018). The area of the PV array is described by assuming the array is composed of standard 200W solar PV panels. Considering the area of a 200W panel (the typical area is 1.24 m^2), Equation 4.46 calculates the total area of a PV array,

$$A_k = P_k^{rated}(kW) \times \frac{1.24}{0.2} (\frac{m^2}{kW}) \tag{4.46}$$

4.5. Improvements made to the operational functions of the natural gas transmission network

The established CGEN model accounts for the costs of operating the gas terminal per unit volume of natural gas injected into the transmission network. In this study, constraints on the availability and costs of different natural gas resources – UKCS, LNG, interconnector imports, and shale gas were implemented.

4.5.1. Implemented constraints on natural gas resources supply

As UK gas production in the UKCS declines, most gas supplies are projected to be imports including liquified natural gas (LNG) (National Grid, 2019a). Due to the increase in import dependency, the UK requires new sources of gas supply including shale gas. Consequently, the gas supply costs will be heavily dependent on the economic viability of using new gas fields within the UKCS, Europe (E.g. Norway gas fields) and LNG market and shipping prices. To use these future scenarios of gas supply, different types of natural gas supply resources were identified as shown in Figure 4.9.

The natural gas resources were characterised by the type (LNG, Interconnector imports, UKCS and Shale), their source and availability (bcm/year), costs of supply (£/mcm) and the connectivity to the natural gas transmission network (via reception terminal or direct connection). This new information was then used as inputs to the CGEN model. Table 4.3 shows an example of an input data set of natural gas resources.

The gas volume ($Q_{i,t}^{res}$) supply from source i was subjected to an average daily availability as described in Equation 4.47.

$$\sum_{t}^{Day} Q_{i,t}^{res} \leq \frac{Q_i^{res,max}}{365} \tag{4.47}$$

The total cost of gas supply from different resources (C_{gas}^{res}) was added to the overall objective function of the CGEN model as described in Equation 4.48.

$$C_{gas}^{res} = \sum_{i}^{\{Gas\ resources\}} \left(C_i^{res} \times Q_{i,t}^{res}\right) \tag{4.48}$$

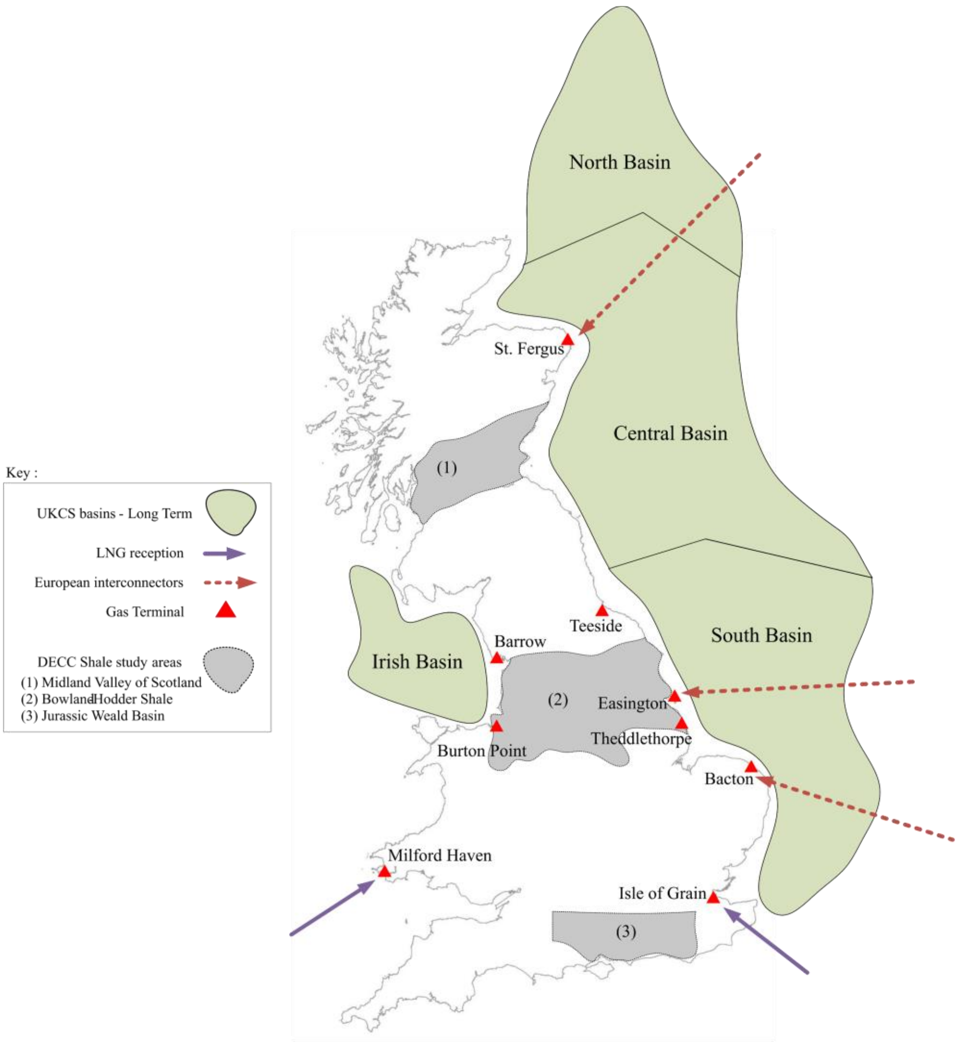

Figure 4.9 – Natural gas resources and interconnections to national transmission system (NTS)

Table 4.3 – An example input data table for the CGEN model considering different natural gas supply resources.

Resource Type	Source (i)	Cost, (C_i^{res}) (£/mcm)	Volume available - ($Q_i^{res,max}$) (bcm /year)	Connectivity
LNG	Qatar	0.22	15	Milford Haven Terminal
Domestic (UKCS)	North Basin	0.1	8	St. Fergus Terminal
European Interconnector	Norway	0.16	20	Easington and St. Fergus terminals
Shale gas	Midland Valley	0.11	1400 (estimated)	Direct connection to the gas network

4.6. Summary

Improvements were made to the established CGEN model that developed a whole GB energy systems model to represent energy resources supply, transmission, distribution, and end-uses. The spatial granularity of the transmission networks was improved to represent natural gas offtake points and electricity grid supply points connected to the gas and electricity distribution networks. The new representative networks were used to integrate energy distribution systems in the CGEN model.

Bi-directional electricity interconnector flows, and characterisation of different natural gas supply resources was modelled. This allowed characterising the connectivity for gas and electricity supply beyond the national boundary.

Additionally, a detailed modelling approach for wind and PV generation was established. This methodology was developed to consider the spatial variability of wind speeds and solar irradiance and to use these weather parameters from future climate projections.

The modifications made in this chapter aim to address the limitation of spatial granularity when modelling and analysing electricity and natural gas transmission networks. Not only the national electricity and gas systems, but also their interconnectivity with other countries was explicitly modelled. The limitation of coarse spatial and temporal granularity used to model renewables was addressed by the new methodology presented in this chapter.

5. Energy Hub modelling of local energy systems in the CGEN model

5.1. Introduction

The established CGEN model (presented in Chapter 4) excludes explicit modelling of local electricity, natural gas and heat distribution systems and their interactions. However, modelling detailed distribution systems in a large gas and electricity transmission network model can dramatically increase the computational requirements. In addition, demand shifting, vehicle to grid and distributed injection of gasses are of emerging importance in the analysis of future integrated energy systems which are not included in the established CGEN model. The research presented in this chapter aims to develop a methodology to include these significant features into the analysis of the CGEN model limiting the increase in computational requirements.

An Energy Hub was used to model integrated local energy supply systems in the CGEN model, and the concept is presented in Section 5.2. The mathematical modelling of the Energy Hub was developed to represent the operation of integrated local electricity, natural gas, heat, and hydrogen supply systems. This is presented in Section 5.3. Demand shifting, vehicle to grid, and biomethane and hydrogen blending were modelled as additional features in the energy hub and are presented in Section 5.4.

5.2. Development of an Energy Hub to represent a local energy system

A local energy supply system example is shown in Figure 5.1(a). It includes gas and electricity distribution systems, and their transmission supply points, a district heating network, and consumers connected to each network (industrial, commercial, and residential). The consumers have rooftop PV and building-level heating systems (CHP, gas boilers, heat pumps).

Figure 5.1(b) shows the Energy Hub representation of the local energy supply system in Figure 5.1(a). The Energy Hub provides an aggregated view of energy supply and demand within the local energy system. The energy supply represents an aggregated installed capacity of electricity generation technologies, heat supply technologies, gas storage, and the total capacity of electricity and natural gas transmission network supply points. Energy demands are aggregated for heating (space heating and hot water) and non-heating (consumer electronics, cooking, EV charging) end-uses.

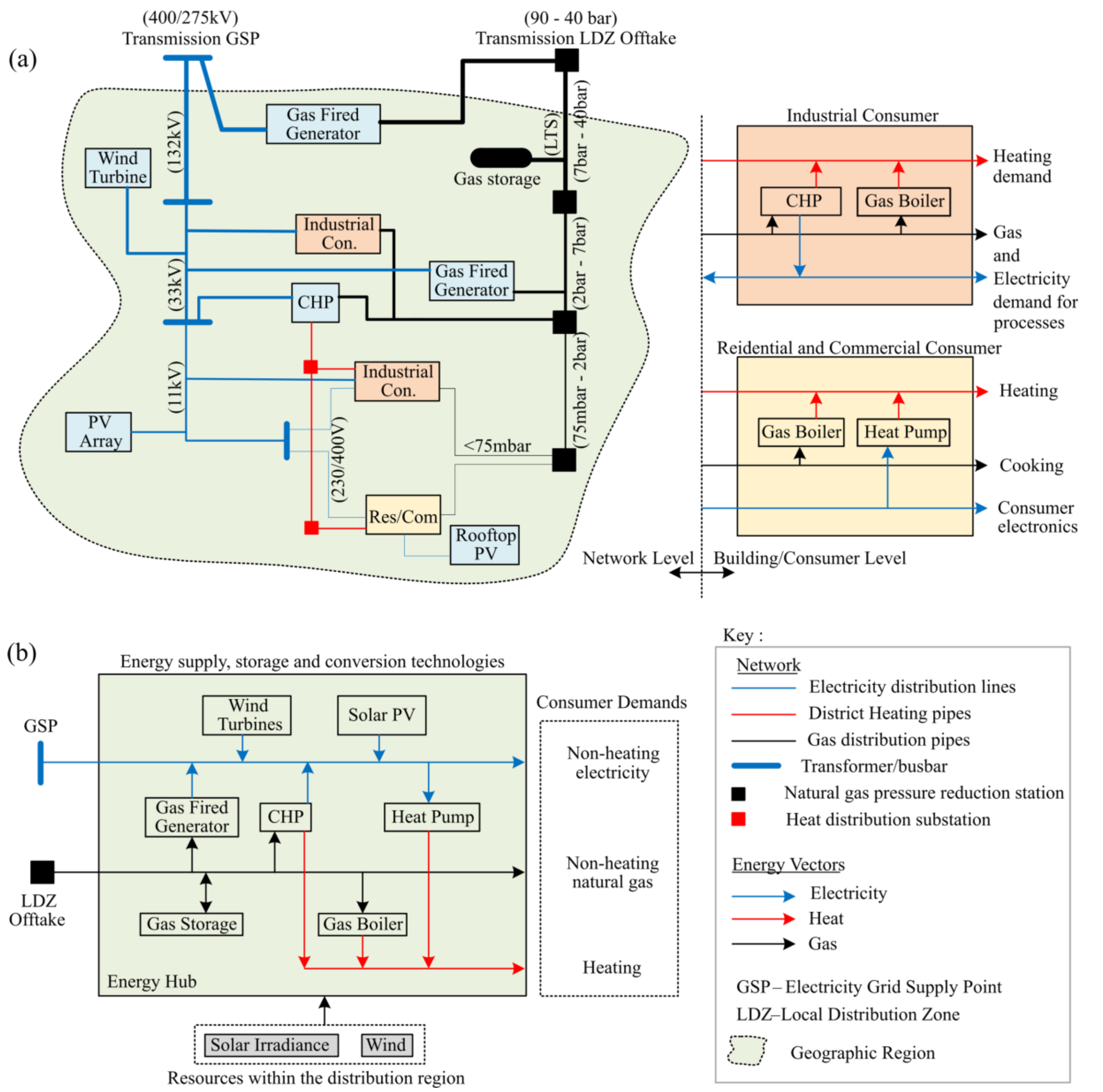

Figure 5.1 – (a) Details of local energy systems within a geographic region and (b) Energy Hub representation of the local energy system.

The Energy Hub represents energy supply, conversion, and storage to meet the heating and non-heating end-use demands. The technologies within the Energy Hub are described using their operational characteristics including heat to power relationship of CHP units, ramp rates of power generation units, and daily operation regimes of gas storage facilities. In addition, wind speed and solar irradiance inputs are used in the simulation of the power output from wind and PV plants.

The interdependencies in operating different local energy supply systems are modelled through energy conversion technologies such as CHP units, gas-fired generators, gas boilers and heat pumps. The physical networks such as electricity distribution, gas distribution, heat networks are not modelled.

5.3. Mathematical modelling of the Energy Hub

The mathematical model of an Energy Hub that represents integrated electricity, natural gas, heat, and hydrogen supply systems, as well as bioenergy and waste to energy systems was developed. Figure 5.2 shows the Energy Hub layout used.

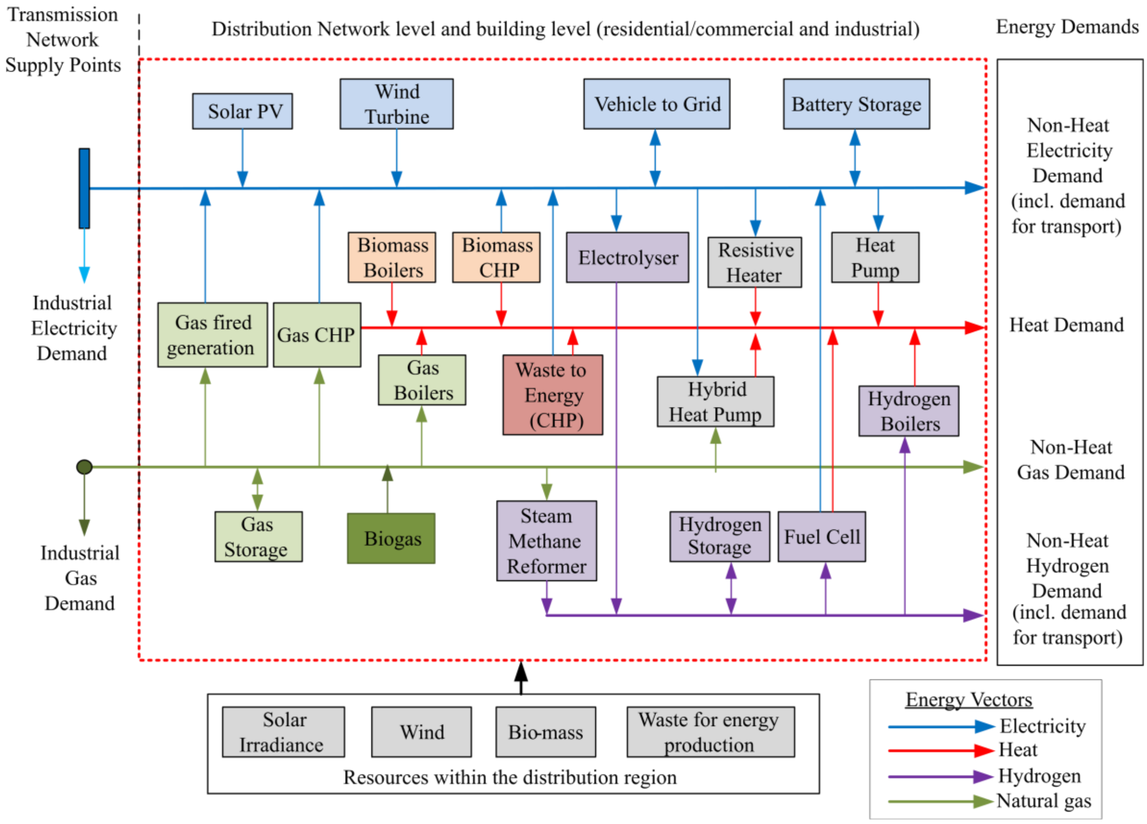

Figure 5.2 – Energy Hub layout used for the mathematical modelling of local integrated electricity, natural gas, heating, and hydrogen supply systems.

The following mathematical equations were derived to describe the operation of the integrated local energy system under steady-state in an hourly time resolution.

- Electricity, natural gas, heat and hydrogen energy supply and demand balance **(Section 5.2.1)**.
- Energy supply constraints from distributed technologies within the Energy Hub, and transmission networks into the Energy Hub **(Section 5.2.2)**.
- Energy conversion relationships **(Section 5.2.3)**.
- Energy storage system operation **(Section 5.2.4)**.
- Resource availability constraints for bioenergy and waste **(Section 5.2.5)**.
- Calculation of operating costs of the energy hub and total CO_2 emissions **(Section 5.2.6)**.

Different parameters were used in these equations to describe the operation of technologies represented in the Energy Hub. Table 5.1 describes the different parameters used in this research.

Table 5.1 – Different parameters used to model the operation of distributed technologies within the Energy Hub

Category	Technology	Parameters
Energy supply	Electricity grid-supply (transmission)	• Electricity supply capacity (MW)
	Gas grid- supply (transmission)	• Gas supply capacity (mcm/day)
	Wind Generation	• Installed capacity (MW) • Wind speed (m/s)
	PV Generation	• Installed capacity (MW) • Solar irradiance (W/m^2)
	Biogas sources	• Rated gas injection capacity (mcm/h)
	Vehicle to Grid	• Total number of vehicles • The capacity of the connection interface (kW) • Energy use for vehicle trips (MWh) • Average vehicle battery capacity (kWh)
Energy conversion	Gas Boiler Heat Pump Hydrogen boiler Resistive heater Biomass boiler Electrolyser Steam methane reformer Gas-fired generator	• Rated Capacity (MW) • Conversion efficiency • Fixed and variable operating costs (£/MWh)
	Biomass CHP Gas CHP Fuel Cell Waste to Energy CHP	• Rated thermal (MW_{th}) and electrical (MW_e) capacity. • Thermal efficiency and electrical efficiency • Fixed and variable operating costs (£/MWh)
Storage	Gas Pressure Bullets Hydrogen storage	• Storage capacity (mcm) • Maximum withdraw and injection rates (mcm/h) • Cost of operating gas storage (£/mcm)
	Gas Line-pack	• Total line-pack available in the local transmission system (mcm/day)
	Battery	• Storage capacity (MWh) • Max/Min charge and discharge rates (MW/h) • Cost of operation (£/MWh)

5.3.1. Energy supply and demand balance

Modelling of energy supply within the Energy Hub represents actual aggregated flows of electricity via electricity distribution lines, and gas, hot water and hydrogen flow in distribution pipes to meet consumer energy demands.

a. Electrical energy balance

Electrical energy supply from the transmission network $\left(E_{e,t}^{tran_{eh}}\right)$ and distributed generators were balanced with the electrical energy demand for heating and non-heating end-uses at time step t. The energy balance equation is given in Equation 5.1.

$$E_{e,t}^{tran_{eh}} + \sum_{i}^{\{distributed\}} E_{e,t}^{i} = \sum_{j}^{\{heating\}} E_{e,t}^{j} + \sum_{k}^{\{hydrogen\}} E_{e,t}^{k} + \sum_{s}^{\{sector\}} E_{s,e,t}^{non-heat} + E_{e,t}^{transport} \tag{5.1}$$

where, $\{distributed\}$ = {Solar PV, Wind Turbine, Gas Turbine, Gas CHP, Biomass CHP, Waste CHP, Vehicle to Grid, Battery Supply, Fuel Cell},

$\{heating\}$ = {Hybrid Heat Pump, Heat Pump, Resistive Heating},

$\{hydrogen\}$ = {Electrolyser} and $\{sector\}$ = {residential, commercial, industrial}.

At time t, non-heating electrical energy demand $\left(E_{s,e,t}^{non-heat}\right)$ is the demand for cooking, lighting, consumer electronics (computing, washing machines and refrigeration) for residential and commercial sectors, as well as the electrical energy demand for industrial processes. Transport electrical energy demand $\left(E_{e,t}^{transport}\right)$ is the electric vehicle charging demand at time step t.

b. Natural gas energy balance

Natural gas supply from the transmission network $\left(E_{g,t}^{tran_{eh}}\right)$, distributed injection of biogas and hydrogen, and gas storage facilities were balanced with the natural gas demand for heating, power generation, hydrogen production and other non-heating purposes at time step t. The energy balance is presented in Equation 5.2.

$$E_{g,t}^{tran_{eh}} + \sum_{i}^{\{distributed\}} E_{g,t}^{i} = \sum_{j}^{\{heating\}} E_{g,t}^{j} + \sum_{k}^{\{power\}} E_{g,t}^{k} + \sum_{l}^{\{hydrogen\}} E_{g,t}^{l} + \sum_{s}^{\{sector\}} E_{s,g,t}^{non-heat} \tag{5.2}$$

$\{distributed\}$ = {Storage Supply, Biogas and hydrogen injected (blending)},

$\{heating\}$ = {Gas Boiler, Hybrid Heat Pump, Gas CHP},

$\{power\}$ = {Gas Turbine}, and $\{hydrogen\}$ = {Steam Methane Reformer}

Gas non-heating demand $\left(E_{s,g,t}^{non-heat}\right)$ is the natural gas demand for cooking and industrial processes at time t.

c. Heat energy balance

Heat supply by district heating technologies and individual heating technologies within buildings were balanced with the total space heating and hot water demand across residential, commercial, and industrial sectors (s). Equation 5.3 shows the heat energy balance at time step t:

$$\sum_{i}^{\{Heating\}} E_{h,t}^{i} = \sum_{s}^{\{sector\}} E_{s,h,t}^{heat\ demand} \tag{5.3}$$

$\{Heating\}$ = {Gas CHP, Gas boiler, Biomass Boiler, Biomass CHP, Waste CHP, Resistive Heating, Heat Pump, Hybrid Heat Pump, Hydrogen Boiler, Fuel Cell}.

$E_{s,h,t}^{heat\ demand}$ is the total heat demand (space heating and hot water) across residential, commercial, and industrial sectors at time t.

d. Hydrogen energy balance

Distributed hydrogen production by electrolysers and steam methane reformers, and hydrogen storage supply were balanced with the hydrogen demand for heating and non-heating end-use. Hydrogen energy balance at timestep t is shown in Equation 5.4.

$$\sum_{i}^{\{Supply\ Tech\}} E_{h_2,t}^{i} = \sum_{j}^{\{heating\}} E_{h_2,t}^{j} + \sum_{s}^{\{sector\}} E_{s,h_2,t}^{non-heat} + E_{h_2,t}^{transport} \tag{5.4}$$

$\{Supply\ Tech\}$ = {Electrolysers, Steam methane reformers, Hydrogen Storage} and,

$\{heating\}$ = {Hydrogen Boiler and Fuel Cell}.

Hydrogen non-heating demand $\left(E_{s,h_2,t}^{non-heat}\right)$ is mainly for industrial processes and for any other consumer demands for hydrogen (e.g. cooking) at timestep t. $E_{h_2,t}^{transport}$ is the hydrogen demand for refuelling hydrogen fuel-cell vehicles at time t.

5.3.2. Energy supply constraints

a. Energy output constraints

The energy output $E_{x,t}^{i}$ from a technology i at a given time t was kept within the maximum output capacity $E_{x}^{i,max}$ as described in Equation 5.5.

$$E_{x,t}^{i} \leq E_{x}^{i,max} ; x = \{electricity, natural\ gas, heat, hydrogen\} \tag{5.5}$$

The aggregated installed capacity of technology type i within the Energy Hub representative region was taken as the maximum output capacity.

b. Gas and electricity supply from the transmission network

Gas and electricity supply from the transmission networks to an Energy Hub was limited by the maximum capacity of each supply point. A daily flow capacity limit $\left(Q_{n}^{tran_{eh},max}\right)$ was imposed for each natural gas supply node (n) connected with the energy hub representative region as shown in Equation 5.6.

$$\sum_{1}^{24} E_{g,t}^{tran_{eh}} \leq Q_{n}^{tran_{eh},max} \times H_{g} \tag{5.6}$$

Here, the factor H_g is the heating value of natural gas taken as 39.6 MJ/m3 (National Grid, 2018a) and converts the daily capacity given in unit of gas flow *mcm* to energy units *MWh*.

The electrical energy supply from the transmission network supply point b to an Energy Hub was constrained by the maximum grid supply point capacity $\left(P_{n}^{tran_{eh},max}\right)$ as described in Equation 5.7.

$$E_{e,t}^{tran_{eh}} \leq P_{b}^{tran_{eh},max} \times t \tag{5.7}$$

c. Electrical energy supply from Wind and PV

Electricity supply from wind and solar PV were modelled using wind speed (v_t) and solar irradiance (I_t) data for the Energy Hub representative region.

1. Electrical energy supply from Wind

The aggregated installed capacity of wind turbines within the Energy Hub representative region was taken as $P^{wind,rated}$. Typical wind speed to power output curve was used to calculate the total wind turbine electrical energy output at a given time t, from the input wind speed data as shown in Equation 5.8

$$E_{e,t}^{wind} = \begin{cases} 0\,;\ if\ v_t \leq v^{cut-in}\ or\ v_t \geq v^{cut-off} \\ \left(\dfrac{v_t - v^{cut-in}}{v^{rated} - v^{cut-in}}\right)\left(P^{wind,rated} \times t\right); if\ v^{cut-in} \leq v_t \leq v^{rated} \\ \left(P^{wind,rated} \times t\right);\ if\ v^{rated} \leq v_t \leq v^{cut-off} \end{cases} \tag{5.8}$$

Here, v^{cut-in}, $v^{cut-off}$, and v^{rated} are the cut-in, cut-off and rated speed given in typical wind speed to power output curve of a wind turbine.

2. Electrical energy from PV

Equation 5.9 was used to calculate the electrical energy supply from the installed PV arrays (including rooftop PV panels) within the Energy Hub representative region at a given time t. Total installed capacity $\left(P^{PV,rated}\right)$ and the input solar irradiance (I_t) data were used in the calculation.

$$E_{e,t}^{PV} = P^{PV,rated} \times t \times \frac{1.24}{0.2} \times \eta \times\ PR\ \times I_t \tag{5.9}$$

Here, η is the efficiency of the solar PV array and PR is the performance ratio of an array that considers additional losses. The total area which is effective for the incoming irradiance within the Energy Hub region is calculated by assuming that the total capacity $\left(P^{PV,rated}\right)$ is composed of individual standard 200W solar PV panels with an area of 1.24m^2.

5.3.3. Energy conversion relationships

Energy conversion technologies provide the coupling between different energy supply systems represented within the Energy Hub. The conversion of input energy a of given technology i to an output energy b was modelled using a conversion efficiency η_{a-b}^{i}. Equation 5.10. shows a generalised equation for energy conversion.

$$E_{b,t}^{i} = \eta_{a-b}^{i} \times E_{a,t}^{i} \tag{5.10}$$

A combined heat and power unit j, converts input energy a to electricity (e) and heat (h). Equation 5.10 describes the conversion a to e with an electrical efficiency and a to h with thermal efficiency. The relationship between heat and electricity outputs was modelled using an average heat to power ratio (HPR^j) as shown in Equation 5.11.

$$E_{h,t}^{j} = HPR^{j} \times E_{e,t}^{j} \tag{5.11}$$

Table 5.2 lists the energy conversion relationships used in the Energy Hub (ETI, 2017b; Jenkins et al., 2010).

Table 5.2 – Energy conversion relationships used in the Energy Hub

Technology (i)	Input (a)	Output (b)	Efficiency (η^i_{a-b}.) and/or HPR^i	
Gas boiler	Natural gas	Heat	$\eta^i_{g-h} = 0.8$	
Gas CHP	Natural gas	heat	$\eta^i_{g-h} = 0.45$	$HPR^i = 1.3{:}1$
		electricity	$\eta^i_{g-e} = 0.34$	
Gas turbine	Natural gas	Electricity	$\eta^i_{g-e} = 0.32$	
Hybrid heat pump	Electricity	Heat	$\eta^i_{e-h} = 2$	
	Natural gas		$\eta^i_{g-h} = 0.8$	
Heat pump	Electricity	Heat	$\eta^i_{e-h} = 2$	
Resistive heater	Electricity	Heat	$\eta^i_{e-h} = 0.98$	
Biomass boiler	Biomass	Heat	$\eta^i_{bio-h} = 0.7$	
Biomass CHP	Biomass	Heat	$\eta^i_{bio-h} = 0.4$	$HPR^i = 1.7{:}1$
		Electricity	$\eta^i_{bio-e} = 0.23$	
Waste CHP	Waste	Heat	$\eta^i_{w-h} = 0.4$	$HPR^i = 1.4{:}1$
		Electricity	$\eta^i_{w-e} = 0.28$	
Electrolysis	Electricity	Hydrogen	$\eta^i_{e-h2} = 0.74$	
Steam methane reform	Natural gas	Hydrogen	$\eta^i_{g-h2} = 0.8$	
Hydrogen boiler	Hydrogen	Heat	$\eta^i_{h2-h} = 0.9$	
Fuel cell	Hydrogen	Heat	$\eta^i_{h2-h} = 0.45$	$HPR^i = 1.5{:}1$
		Electricity	$\eta^i_{h2-e} = 0.3$	

5.3.4. Energy storage systems modelling

Energy storage systems within the Energy Hub were operated to balance energy supply and demand within a day and were recharged to initial energy storage levels at the end of each day. These general rules were applied when modelling electricity, natural gas and hydrogen storage systems.

The energy balance for an energy storage system i is presented in Equation 5.12.

$$E^{i,store}_{a,t} = E^{i,store}_{a,t-1} \pm E^i_{a,t} \tag{5.12}$$

Here, $E_{a,t}^{i,store}$ is the energy stored and $E_{a,t}^{i}$ is the energy supply at a given time t. If ($E_{a,t}^{i}$) > 0, it states that the storage system is charging and if ($E_{a,t}^{i}$) < 0, the storage system is discharging. The energy stored at a given time step t was kept below the maximum energy storage capacity as given in Equation 5.13.

$$\left(E_{a}^{i,store,max} \times 0.2\right) \leq E_{a,t}^{i,store} \leq E_{a}^{i,store,max} \tag{5.13}$$

Where, i = {Gas Storage, Battery Storage, Hydrogen storage}.

The maximum storage capacity for natural gas was taken as the aggregated storage capacity of gas pressure bullets and the total linepack available within the high-pressure distribution system (which operates at 7 – 40 bar) within the energy hub representative region.

5.3.5. Resource availability

The energy supply from biomass boilers, biomass CHP and waste CHP technologies were constrained by the availability of biomass and municipal solid waste. An annual availability was calculated by combining the resources within the energy hub representative region itself, and the resources that can be transported into the region from other neighbouring regions. The annual availability of biomass and municipal solid waste resources were used as inputs to the energy hub model.

Equation 5.14 describes the total biomass consumed $\left(B_{t}^{eh}\right)$ for the heat supplied by the biomass boiler $\left(E_{h,t}^{bio\ boiler}\right)$ and biomass CHP $\left(E_{h,t}^{bio\ CHP}\right)$ at time t. The total solid waste consumed $\left(W_{t}^{eh}\right)$ at time t to supply heat via waste CHP units $\left(E_{h,t}^{waste\ CHP}\right)$ is given by Equation 5.15.

$$B_{t}^{eh} = \left\{\left(\frac{E_{h,t}^{bio\ boiler}}{\eta_{bio-h}^{bio\ boiler}}\right) + \left(\frac{E_{h,t}^{bio\_CHP}}{\eta_{bio-h}^{bio\ CHP}}\right)\right\} \times \frac{t}{GCV_{bio}} \tag{5.14}$$

$$W_{t}^{eh} = \left(\frac{E_{h,t}^{waste\ CHP}}{\eta_{w-h}^{waste\ CHP}}\right) \times \frac{t}{GCV_{w}} \tag{5.15}$$

Here, GCV_{bio} is the average gross calorific value for biomass (wood chip and wood pellets) and GCV_{w} is the gross calorific value of municipal solid waste. The total biomass and solid waste consumptions were constrained by their availability, as described in Equations 5.16 and 5.17.

$$\sum_{i=1}^{24} B_{t}^{eh} \leq \frac{B^{eh,available}}{365} \tag{5.16}$$

$$\sum_{i=1}^{24} W_{t}^{eh} \leq \frac{W^{eh,available}}{365} \tag{5.17}$$

5.3.6. Emissions and operating costs

Emissions of CO_2e and operating costs of the integrated energy system represented by the energy hub were calculated.

a. Equivalent CO_2 Emissions

Emissions of CO_2e from heat supply, distributed electricity generation, distributed hydrogen production and non-heating use of fuels (natural gas, biomass, solid waste, oil and other fossil fuels) were calculated. An equivalent CO_2 emissions factor based on the gross calorific value of a unit fuel was used to perform the emissions calculation. These emission factors are shown in Table 5.3.

Table 5.3 – Emissions factors used in the energy hub model

Fuel (j)	Emissions Factor (Ef_j), tCO_2e/MWh, (BEIS, 2018f)
Natural gas	0.18416
Biomass (wood chips/wood pellets)	0.01270
Biogas	0.00023
Oil	0.26789
Solid fuel (coal, industrial)	0.32442
Municipal solid waste (in combustion and Anaerobic digestion)	0.0218

The total equivalent CO_2 emissions emitted at a given timestep t within the energy hub representative region is given by,

$$Em_t^{eh}\ (tCO_2e) = \sum_{j}^{\{fuel\}} \sum_{j_i}^{\{end\ use\ demand\}} E_{j,t}^{j_i} \times Ef_j \tag{5.18}$$

Where, {fuel} = {natural gas, oil, biomass, solid fuel, solid waste) and,

{end use demand} = {{*natural gas*: gas turbine, gas boiler, gas CHP, gas boiler in hybrid heat pump, steam methane reformer, non-heating}, {*biomass*: biomass boiler, biomass CHP}, {*solid waste*: waste CHP}, {*oil*: non-heating}, {*solid fuel*: non-heating}.

b. Energy hub operating costs

The costs were calculated for operating the electricity, natural gas, heating, and hydrogen supply systems in the energy hub. The total operating costs include:

(i) **operating costs of distributed technologies in the energy hub**: This includes fixed and variable costs $\left(C^{i,f\&v}\right)$ of operating different technologies (i) with respect to energy outputs $\left(E^{i}_{output,t}\right)$, and fuel costs for biomass $\left(C^{fuel}_{bio}\right)$and solid waste $\left(C^{fuel}_{w}\right)$.

(ii) **costs for transmission gas and electricity fuels for the energy hub:** This includes the cost of electricity $\left(C^{elec,sp}\right)$ and natural gas $\left(C^{gas,sp}\right)$ for the total electricity $\left(E^{tran_{eh}}_{e,t}\right)$ and natural gas flows $\left(E^{tran_{eh}}_{g,t}\right)$ from the transmission network to the energy hub.

(iii) **carbon costs** $\left(C^{carbon}\right)$ applied for the emissions of CO_2e emitted locally $\left(Em^{eh}_{t}\right)$.

(iv) **load shedding costs** $\left(C^{ue}, C^{ug}\right)$ for any unserved demand for electricity $\left(E^{ue}_{e,t}\right)$ or natural gas $\left(E^{ug}_{g,t}\right)$. Since heating and hydrogen are supplied either by electricity and/or natural gas, separate variables for unserved heat and hydrogen demands were not modelled.

Equation 5.19 gives the total operating cost of the energy hub at time t $\left(C^{eh}_{t}\right)$:

$$C^{eh}_{t} = \underbrace{\left\{\sum_{i}^{\{Tech\}} E^{i}_{output,t} \times C^{i,f\&v}\right\} + \left\{\sum_{j}^{\{bio,w\}} E^{eh}_{j,t} \times C^{fuel}_{j}\right\}}_{\textbf{(i)}} + \underbrace{\left\{Em^{eh}_{t} \times C^{carbon}\right\}}_{\textbf{(iii)}}$$
$$+ \underbrace{\left\{\sum_{k}^{\{gas,elec\}} E^{tran_{eh}}_{k,t} \times C^{k,sp}\right\}}_{\textbf{(ii)}} + \underbrace{\left\{C^{ug} \times E^{ug}_{g,t} + C^{ue} \times E^{ue}_{e,t}\right\}}_{\textbf{(iv)}} \tag{5.19}$$

where {Tech} is the list of technologies available in the energy hub, and {bio, w} refers to biomass and solid waste fuel.

5.4. Modules and features developed in the energy hub model

In addition to the modelling of energy supply, conversion and storage in the energy hub, additional features were developed. These were to simulate,

- demand shifting (5.3.1)
- energy demand for transport and vehicle to grid (5.3.2)
- biogas and hydrogen blending into the natural gas system (5.3.3)

5.4.1. Electricity demand Shifting

Demand shifting schemes allows the system operator to switch pre-agreed electricity demand from peak hours to off-peak hours, such that the total operating costs of the energy hub is minimised. An illustrative example of demand shifting is shown in Figure 5.3.

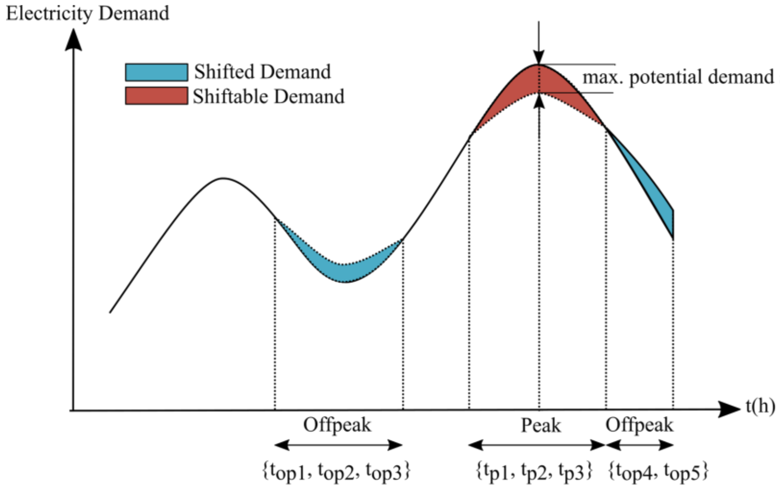

Figure 5.3 – Illustration of demand shifting

A demand shifting module was implemented to allow the user to provide the required inputs. These inputs include the peak hours (t_{p1}, t_{p2}, t_{p3}), off-peak hours $(t_{op1}, t_{op2}, t_{op3}, t_{op4}, t_{op5})$, and the maximum potential demand shift (k_s %) from the total electricity demand at a given peak time. The maximum potential demand shift (k_s) was assigned to different sectors s, i.e. residential, commercial, industrial. Figure 5.4 shows an outline of the developed demand shifting module.

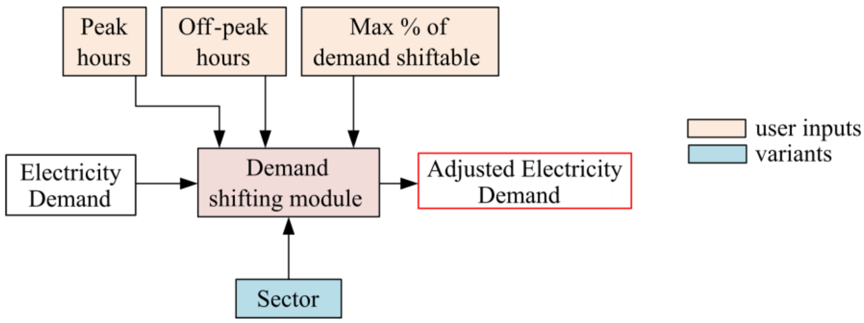

Figure 5.4 – Outline of the developed demand shifting module.

Given the inputs, the demand shifting was modelled using two decision variables. These are the demand to be shifted from a peak hour $\left(\delta E_{s,e,t}^{shift}\right)$, and the demand to be assigned to an off-peak hour $\left(\delta E_{s,e,t}^{assign}\right)$. These variables were determined such that the total cost of operating the energy hub to meet the adjusted electricity demand was minimised.

Equation 5.20 constrains the demand to be shifted from a peak hour.

i.e. for $t = \{t_{p1}, t_{p2}, t_{p3}\}$, and sector s,

$$\delta E_{s,e,t}^{shift} \leq \frac{k_s}{100} \times E_{s,e,t}^{non-heat} \tag{5.20}$$

The shifted demand $\left(\delta E_{s,e,t}^{shift}\right)$ and the assigned demand $\left(\delta E_{s,e,t}^{assign}\right)$ satisfies Equation 5.21 for sector s within 24 hours.

$$\sum_{t}^{\{t_{p1},t_{p2},t_{p3}\}} \delta E_{s,e,t}^{shift} = \sum_{t}^{\{t_{op1},t_{op2},t_{op3},t_{op4},t_{op5}\}} \delta E_{s,e,t}^{assign} \tag{5.21}$$

The adjusted electricity demand is calculated by Equations 5.22 for peak hours. i.e. For $t = \{t_{p1}, t_{p2}, t_{p3}\}$,

$$E_{s,e,t}^{adjusted} = E_{s,e,t} - \delta E_{s,e,t}^{shift} \tag{5.22}$$

Equation 5.23 calculates the adjusted electricity demand for off-peak hours. i.e. For $t = \{t_{op1}, t_{op2}, t_{op3}, t_{op4}, t_{op5}\}$,

$$E_{s,e,t}^{adjusted} = E_{s,e,t} + \delta E_{s,e,t}^{assign} \tag{5.23}$$

For any timestep t outside the defined peak and off-peak hours,

$$E_{s,e,t}^{adjusted} = E_{s,e,t} \tag{5.24}$$

The adjusted electricity demand $E_{s,e,t}^{adjusted}$ is then used in the energy hub electricity supply and demand balancing.

5.4.2. Energy demand for transport and vehicle to grid modelling

An energy transport module was implemented to calculate the availability of electrical energy in EV batteries for vehicle to grid (V2G) services. The number of EVs, number of EV trips at each hour and electricity use in the battery for each EV trip were used as inputs. A road transport model (Lovrić et al., 2017a) was used to obtain these inputs for the energy hub geographic region.

An average EV battery capacity of 30kWh was assumed and at a given time t, it was assumed that 20% of stationary vehicles provide the vehicle to grid services at a power output of 7kW (Imperial College, 2019). The power output, average battery capacity and the portion of stationary vehicles that provide V2G are made as user-defined inputs to the model.

Figure 5.5 shows the electrical energy use in the battery for EV trips (red bars) and the electrical energy available to provide V2G services (black bars) during an average day. As shown in Figure 5.5, the energy-transport module calculates the availability of electrical energy in the EV batteries for V2G services, and its variability during the day with respect to the daily travelling behaviour.

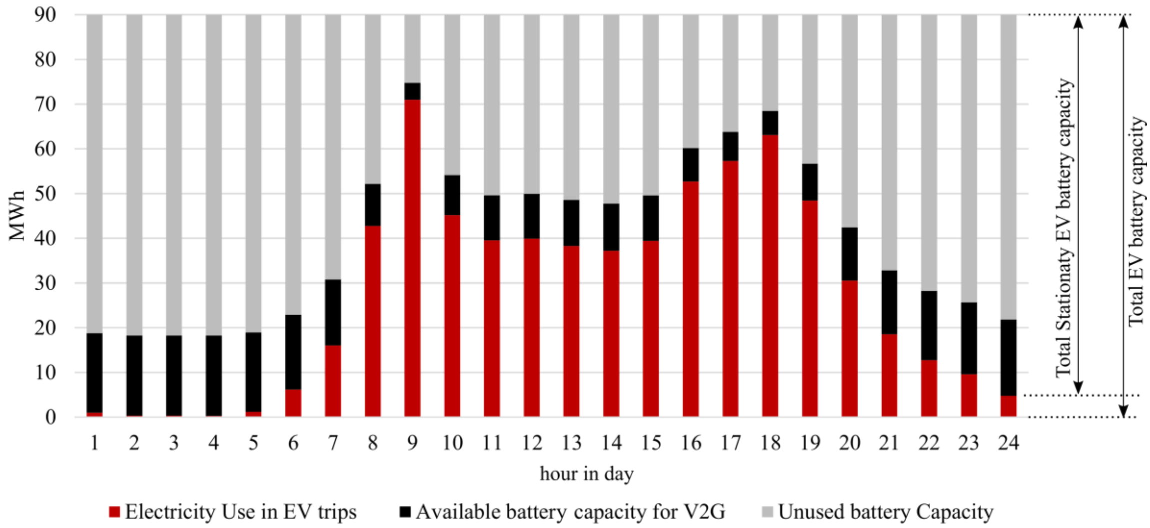

Figure 5.5 – Illustration of electrical energy available in EV batteries for vehicle to grid

Equation 5.25 models the electrical energy stored in EV batteries at time t $\left(E_{e,t}^{EV,store}\right)$. This includes electrical energy flows from vehicle to grid ($E_{e,t}^{V2G}$) and grid to vehicle ($E_{e,t}^{G2V}$), and the charging demand ($E_{e,t}^{transport}$).

$$E_{e,t}^{EV,store} = E_{e,t-1}^{EV,store} + \eta_e^{EV} \times \left(E_{e,t}^{G2V} - E_{e,t}^{V2G} + E_{e,t}^{transport}\right) \qquad (5.25)$$

Here, η_e^{EV} is the efficiency of the EV battery. The usual charging demand $E_{e,t}^{transport}$ is to fulfil the electrical energy required for trips. To make sure that this is not used as a vehicle to grid $\left(E_{e,t}^{V2G}\right)$ service, an additional charging demand variable is introduced as the grid to vehicle ($E_{e,t}^{G2V}$) which is provided back to the grid as a service. The grid to vehicle and vehicle to grid electrical energy flows satisfy the following relationship over 24 hours.

$$\sum_{t=1}^{24} E_{e,t}^{G2V} = \sum_{t=1}^{24} E_{e,t}^{V2G} \qquad (5.26)$$

Using the assumption that only 20% of stationary EV's ($N_{stationary,t}^{EV}$) provide the vehicle to grid services at a power output of 7kW per vehicle, Equation 5.26 constrains the electrical energy flow between the vehicles and the electricity network at time t.

$$E_{e,t}^{V2G}, E_{e,t}^{G2V} \leq 7 \times N_{stationary}^{EV} \times 0.2 \qquad (5.27)$$

The energy stored in the EV battery $\left(E_{e,t}^{EV,store}\right)$ at any time t is constrained by the total EV battery capacity $E_e^{EV,store,max}$ as shown in Equation 5.28.

$$E_{e,t}^{EV,store} \leq E_{e}^{EV,store,max} \tag{5.28}$$

5.4.3. Biogas and hydrogen blending with natural gas

As biogas is low in carbon content compared to natural gas and hydrogen is carbon-free, the use of a gas mixture reduces the overall emissions from power generation and heat supply in the energy hub. The equivalent carbon emissions factor for the gas mixture $\left(Ef_{mix,t}\right)$ was modelled by the energy content of the constituent gas i $\left(E_{i,t}^{i}\right)$ and its emission factors (Ef_i) as shown in Equation 5.29.

$$Ef_{mix,t} = \sum_{i}^{\{natural\ gas,\ biogas, h_2\}} \frac{E_{i.t} \times Ef_i}{E_{mix,t}^{total}} \tag{5.29}$$

The injection of biogas ($Q_{bio,t}$)and hydrogen volumes ($Q_{h_2,t}$) were represented by a natural gas volume ($Q_{g,t}^{bio\ eq}$, $Q_{g,t}^{h_2\ eq}$) at standard pressure and temperature with an equal energy content as shown in Equation 5.30.

$$\begin{gathered} E_{g,t}^{bio} = Q_{g,t}^{bio\ eq} \times GCV_g = Q_{bio,t} \times GCV_{bio} \text{ and} \\ E_{g,t}^{h_2} = Q_{g,t}^{h_2\ eq} \times GCV_g = Q_{h_2,t} \times GCV_{h_2} \end{gathered} \tag{5.30}$$

The equivalent natural gas energy content of injected biogas $\left(E_{g,t}^{bio}\right)$ and hydrogen $\left(E_{g,t}^{h_2}\right)$ were used in the energy hub natural gas supply-demand balance equation.

Biogas and hydrogen injections into the gas distribution system were allowed within pre-defined limits (e.g. 20% hydrogen injection by volume) by the total gas volume $\left(Q_t^{total}\right)$. Equation 5.31 calculates the total gas volume in the gas distribution system at timestep t. This includes the gas volume supplied from the transmission network $\left(Q_{g,t}^{tran_{eh}}\right)$, gas volume supplied by gas storage facilities (Q_t^S), and injected biogas $\left(Q_{bio,t}\right)$and hydrogen $\left(Q_{h_2,t}\right)$volumes.

$$Q_{mix,t}^{total} = Q_{g,t}^{tran_{eh}} + Q_{g,t}^{S} + Q_{bio,t} + Q_{h_2,t} \tag{5.31}$$

Biogas and hydrogen injection limits were then modelled using Equations 5.32.

$$\left(\frac{Q_{h_2,t}}{Q_{mix,t}^{total}}\right), \left(\frac{Q_{bio,t}}{Q_{mix,t}^{total}}\right) \leq (injection\ limit\ by\ volume) \tag{5.32}$$

5.5. Summary

An energy hub model was developed to represent local integrated electricity, natural gas, heat and hydrogen supply systems. The energy hub provides an aggregate view of local distributed energy supply resources, technologies and network infrastructure within a given geographic region. Additional features were developed in the energy hub to model demand shifting for electricity, electric vehicle to grid services and distributed injection of biogas and hydrogen. The energy hub modelling was used to represent local energy supply systems in the CGEN model.

The Energy Hub approach addresses the limitation in the established CGEN model regarding the coarse spatial granularity of modelling local energy systems. Also, the Energy Hub approach captures significant features of energy supply, conversion and storage, and interactions between different energy systems excluding detailed modelling of electricity, natural gas, heat, and hydrogen distribution networks. This allowed the provision to model new features such as demand shifting, vehicle to grid and distributed injection of gases.

6. Integration of Energy Hubs into the CGEN model

6.1. Introduction

The research presented in this chapter extends the established CGEN model by integrating local energy system representations using Energy Hubs. This methodology allows the modelling and analysis of spatially variable local electricity, gas, heating and hydrogen distribution systems with the backbone gas and electricity transmission networks as an integrated system.

The following steps describe the development of the new integrated model, the CGEN+Energy Hubs Model.

- Develop geographic regions to model local energy systems across GB using Energy Hubs (described in section 6.2).
- Couple each Energy Hub with the national electricity and natural gas transmission networks (described in section 6.3).
- Extend the optimisation model of CGEN to include energy hub operating costs and constraints (described in section 6.4).

In addition, the CGEN+Energy Hubs Model was integrated into the National Infrastructure Systems Model, NISMOD and database (ITRC, 2019a). This allows the combined analysis of energy systems with different interdependent sectors such as transport and water supply, which at present are done in isolation. Recent reports (BEIS, 2020; CCC, 2019a; National Grid, 2020a) highlight the importance of such combined analysis of different interdependent sectors to develop coherent policy that meets stringent emission targets.

The CGEN+Energy Hubs Model was further developed within NISMOD to (described in section 6.5),

- use energy demand inputs from a National Energy Demand Model.
- model energy demand for transport using outputs from a National Transport Model.
- model cooling water requirement for power generation using outputs from a National Water Supply Model.

6.2. Geographic regions to model local energy systems in GB

6.2.1. Geographic regions

Geographic regions were used to model Energy Hubs that represent local energy systems in GB. The number of geographic regions was chosen to be equal to the number of electricity transmission network busbars. This allowed a 1 to 1 mapping of electricity transmission busbars to the Energy Hub geographic regions and thus simplified the tasks to connect Energy Hubs to the transmission networks. To ensure this mapping, the Energy Hub geographic regions were needed to be designed based on electricity transmission network boundaries.

The electricity busbars as shown in Figure 6.1(a) correspond to the electricity transmission network boundaries shown in Figure 6.1(b). The electricity transmission network boundaries are defined by the National Grid ESO, considering major sources of generation, significant route corridors and major demand centres (National Grid, 2019c).

The electricity transmission network boundaries in Figure 6.1 (b) were mapped on to the Local Authority Districts (shown as the grey areas) shown in Figure 6.1(c) to develop the boundary of each energy hub geographic region (shown as the red lines). The mapping was performed in ArcGIS software using its geoprocessing tools. The developed energy hub geographic regions are shown in Figure 6.1(d).

Each energy hub geographic region is defined as a group of Local Authority Districts. The Local Authority Districts (LAD) were used due to the availability of Census data, energy demand data, and distributed generation capacity data (BEIS, 2018a; Green Alliance and RegenSW, 2016).

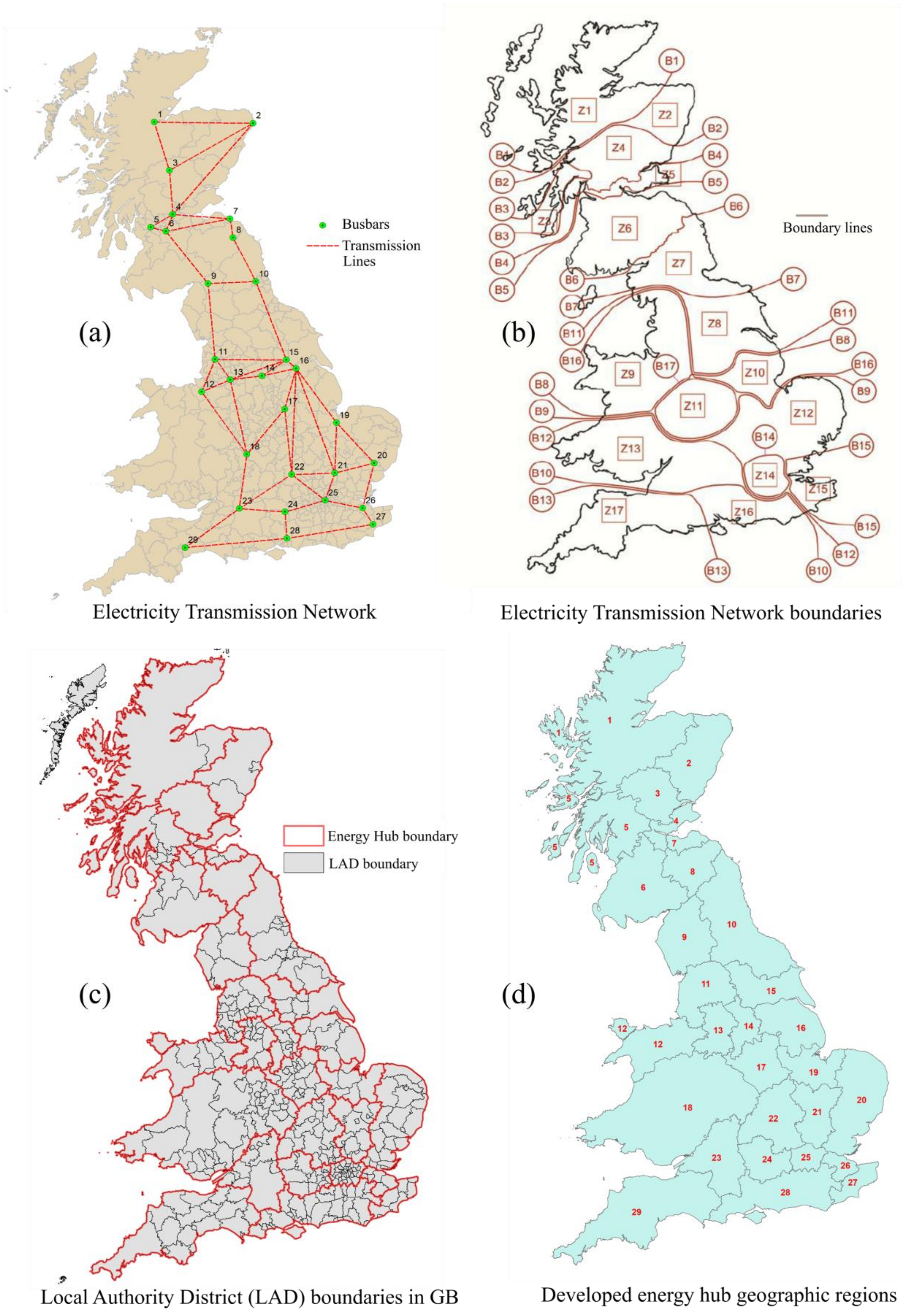

Figure 6.1 – Development of energy hub geographic region boundaries

6.2.2. Regional data

Table 6.1. lists the different data sources used to calculate the capacity of electricity generation and heat supply within each Energy Hub.

Table 6.1 – Data collected to calculate electricity generation and heat supply capacity

Capacity data	Source	Spatial granularity	Licence
Electricity generation (National and regional)	(BEIS, 2018h), (National Grid, 2019a)	National	Open
Distributed electricity generation	(Electricity North West, 2018)	Distribution region[4]	Available on request
	(SP Energy, 2018)		Available on request
	(SSE, 2018)		Open
	(WPD, 2018a, 2018b)		Available on request
	(UKPN, 2018)		Open
	(Nothern Power Grid, 2018)		Open
Regional PV, Wind, Anaerobic Digestion and Micro CHP	(BEIS, 2018g)	Local Authority District	Open
Electricity generation (National and regional) and its geospatial data	(Carbon Brief, 2016b)	Point Locations (Lat, Long)	Available on request
Regional heat supply	(Green Alliance and RegenSW, 2016)	Local Authority District	Available on request
Combined heat and power units	(BEIS, 2018i)	Geospatial (Lat, Long)	Available on request

[4] This is the distribution network operator (DNO) region. Typically, a DNO region was assigned to a collection of Local Authority Districts.

The collected data were mapped onto the energy hub geographic regions and geospatial tools in ArcGIS were used to calculate the capacity of electricity generation and heat supply. Figure 6.2 shows a summary of distributed electricity generation capacity for wind, PV, and natural gas-fired generation plants (including gas CHPs) across energy hub regions for the year 2015. A summary of data collected for each energy hub geographic region is presented in Appendix A.

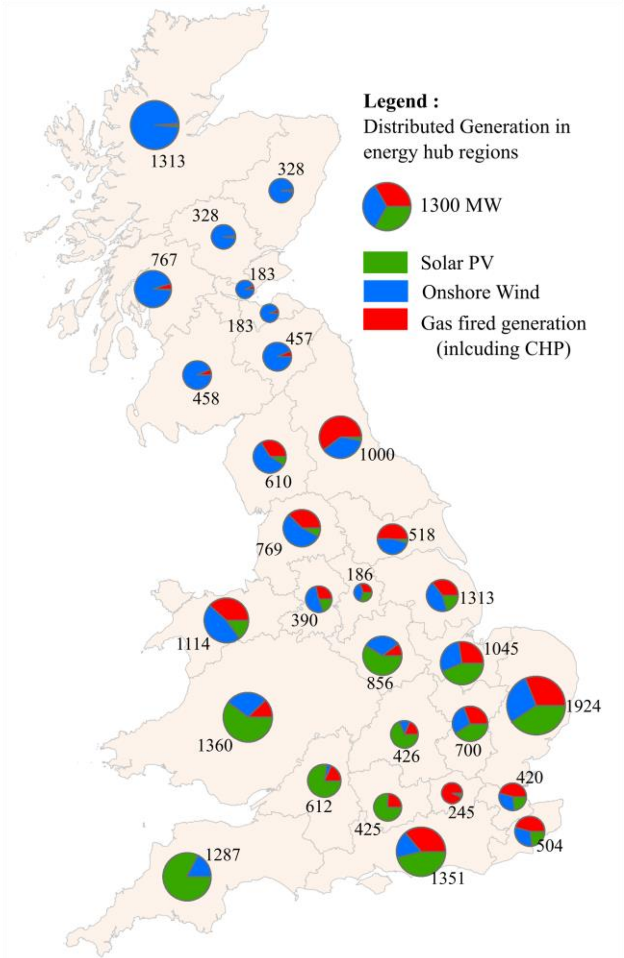

Figure 6.2 – Electricity generation capacity data for wind, PV and gas fired generation used in the Energy Hubs

6.3. Coupling of Energy Hubs with the transmission networks

The Energy Hubs were coupled to the electricity and natural gas transmission networks via electricity busbars and natural gas offtake nodes. Electricity and natural gas transmission networks were mapped on to the energy hub geographic boundaries as shown in Figure 6.3 (a). Each Energy Hub was connected to one electricity busbar and multiple gas offtake nodes within an Energy Hub's geographic boundary. All the gas offtake nodes supply gas to the connected Energy Hub.

An example spatial map for the Energy Hub 29 is shown in Figure 6.3 (b). The Energy Hub is connected to a set of gas offtake nodes $N^{offtake} = \{62,63,64,69\}$ and electricity busbar 29. Figure 6.3(c) shows the total gas $(E_{g,t}^{tran_{29}})$ and electrical $(E_{e,t}^{tran_{29}})$ energy flows from the transmission networks into the Energy Hub 29.

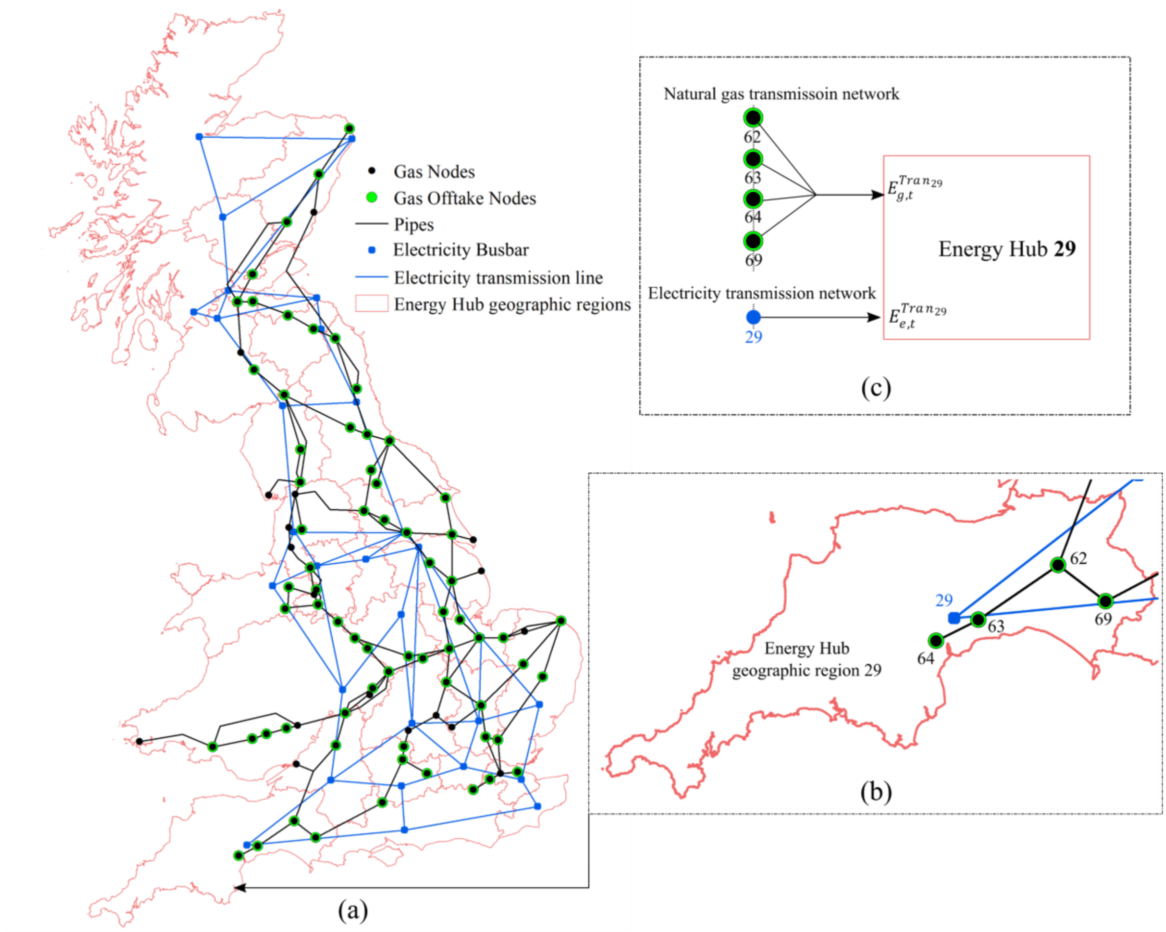

Figure 6.3 – (a) Spatial map of energy hub geographic regions, and gas and electricity transmission networks, (b) example spatial map of the Energy Hub 29 with the transmission networks, and (c) representation of energy flows from transmission networks to the Energy Hub.

6.3.1. Coupling energy hub models with the natural gas transmission network model

a. Case 1: Connecting to gas transmission offtake nodes within the Energy Hub's geographic boundary

Equation 6.1 models the total gas energy flow into the Energy Hub 29 $(E_{g,t}^{tran_{29}})$ as a sum of gas energy flow from each connected transmission gas offtake node n. Given that Energy Hub 29 is connected to a set of gas offtake nodes $N^{offtake} = \{62,63,64,69\}$,

$$E_{g,t}^{tran_{29}} = \sum_{n}^{N^{offtake}} Q_{n,t}^{tran_{29}} \times H_g \tag{6.1}$$

Here, $Q_{n,t}^{tran_{29}}$ is the gas volume flowing from gas offtake node n to the Energy Hub 29. H_g is the heating value of natural gas taken as 39.6 MJ/m3 (National Grid, 2018a) to convert gas volume to energy.

The gas flow from each transmission offtake node n into the Energy Hub 29 was kept within the daily metered gas offtake capacity $\left(Q_n^{offtake,max}\right)$ as described in Equation 6.2.

$$\sum_{t}^{24} Q_{n,t}^{tran_{29}} \leq Q_n^{offtake,max} \tag{6.2}$$

b. <u>Case 2: No gas offtake nodes available within the Energy Hub's geographic boundary</u>

Several energy hubs do not have a gas offtake node within their geographic boundaries. In these cases, the nearest gas node to the boundary of the Energy Hub was chosen by the Nearest Feature analysis in ArcGIS. Only the chosen offtake node supply gas to the Energy Hub. Figure 6.4 shows an example for Energy Hub 1.

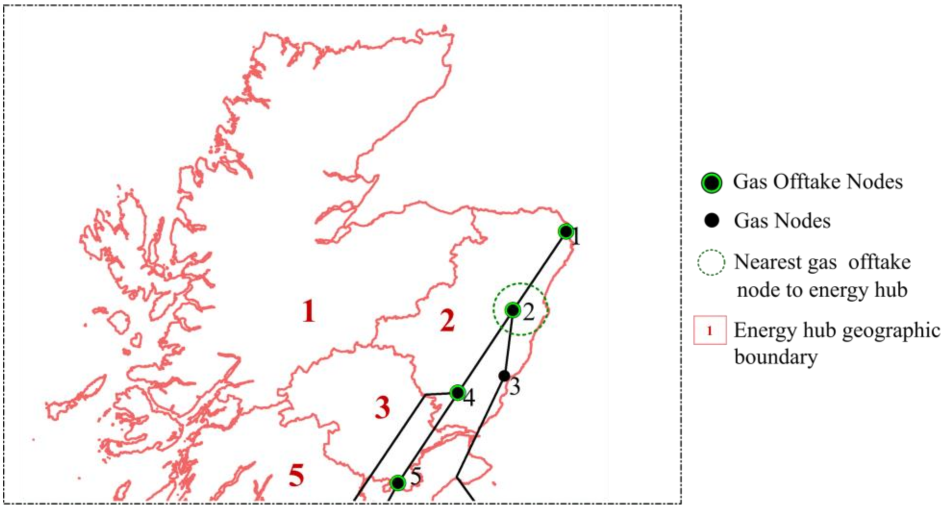

Figure 6.4 – Nearest gas offtake node selected for the energy hub geographic boundary 1

The closest gas offtake node to the Energy Hub 1 is gas offtake node 2. Only the gas offtake node 2 supply gas to the Energy Hub 1.

The gas node 2 is therefore connected to both Energy Hub 1 and 2. Equation 6.3 describes the daily metered gas offtake capacity of node 2 $\left(Q_2^{offtake,max}\right)$ constrain the sum of gas flow from node 2 to Energy Hub 1 $\left(Q_{2,t}^{tran_1}\right)$ and Energy Hub 2 $\left(Q_{2,t}^{tran_2}\right)$.

$$\sum_{t}^{24}\left(Q_{2,t}^{tran_1} + Q_{2,t}^{tran_2}\right) \leq Q_2^{offtake,max} \tag{6.3}$$

A generalised gas flow constraint for a gas offtake node n, which is connected to multiple Energy Hubs is described in Equation 6.4.

$$\sum_{k}^{\{Connected\ Energy\ Hubs\}} \sum_{t}^{24} Q_{n,t}^{tran_k} \leq Q_n^{offtake,max} \tag{6.4}$$

c. Total gas demand at a natural gas transmission offtake node

The total gas demand at a transmission network gas offtake node n $\left(Q_{n,d,t}^{tran}\right)$ is calculated by Equation 6.5. The total gas demand equals the gas flow into the Energy Hub k $\left(Q_{n,t}^{tran_k}\right)$, gas demand for industrial consumers $\left(Q_{n,t}^{tran,ind}\right)$ and gas demand for power generation plants $\left(Q_{n,t}^{tran,powerGen}\right)$ connected at the transmission gas offtake node n.

$$Q_{n,d,t}^{tran} = Q_{n,t}^{tran_k} + Q_{n,t}^{tran,ind} + Q_{n,t}^{tran,powerGen} \tag{6.5}$$

Here, $Q_{n,t}^{tran_k}$ characterises natural gas consumed within the Energy Hub k, for heating and other non-heating end uses, hydrogen production and distributed gas storage operation. The total gas demand from each offtake node is used for the nodal gas flow balance within the natural gas transmission network.

6.3.2. Coupling Energy Hubs with the electricity transmission network

Equation 6.6 converts the electrical power flow from busbar b $\left(P_{b,t}^{tran_{29}}\right)$ to electrical energy flow into the Energy Hub 29 $\left(E_{e,t}^{tran_{29}}\right)$.

$$E_{e,t}^{tran_{29}} = P_{b,t}^{tran_{29}} \times t \tag{6.6}$$

Electrical power flow from the transmission busbar into the Energy Hub 29 was kept within the transmission grid supply point capacity $\left(P_b^{sup,max}\right)$ as described in Equation 6.7.

$$P_{b,t}^{tran_{29}} \leq P_b^{sup,max} \tag{6.7}$$

The total electricity demand at transmission busbar b $\left(P_{b,d,t}^{tran}\right)$ is calculated by Equation 6.8. The total electricity demand equals to the electrical power flow into the Energy Hub k $\left(P_{b,t}^{tran_k}\right)$ and electricity demand for industrial consumers $\left(P_{b,t}^{tran,ind}\right)$ connected at transmission busbar b.

$$P_{b,d,t}^{tran} = P_{b,t}^{tran_k} + P_{b,t}^{tran,ind} \tag{6.8}$$

Here, $\left(P_{b,t}^{tran_k}\right)$ characterises electricity consumed within the Energy Hub k, for heating and other non-heating end uses including transport, hydrogen production and distributed battery storage operation. The total electricity demand at each busbar is used for the busbar electrical power flow balance within the electricity transmission network.

6.4. The CGEN+Energy Hubs Model

6.4.1. Model outline

Inputs, model components and outputs of the CGEN+Energy Hubs Model are shown in Figure 6.5.

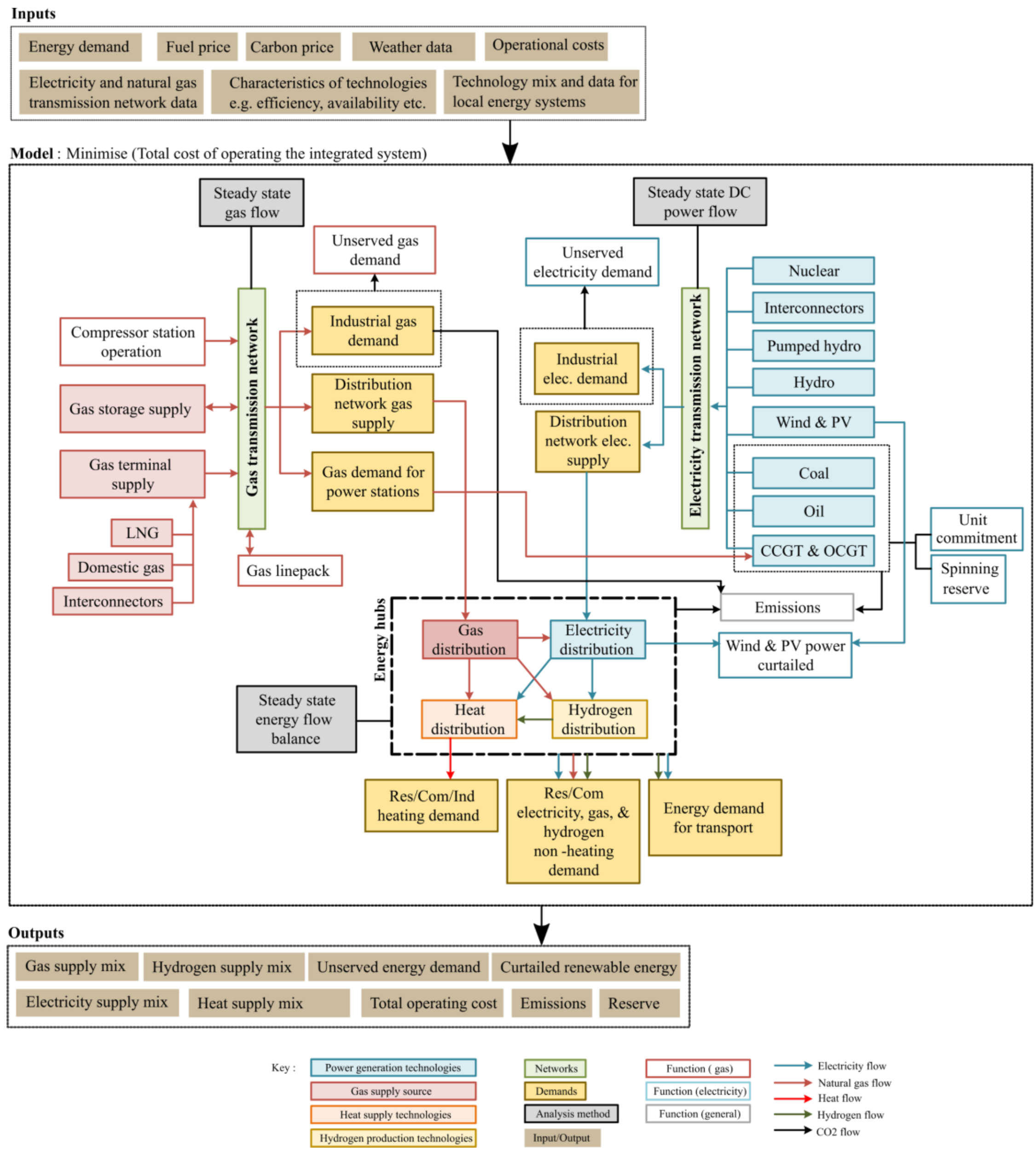

Figure 6.5 – Outline of the CGEN+Energy Hubs Model

a. Input database

A PostgreSQL database was developed to manage input data sets to the model. Input data sets include energy demand, energy system (e.g. transmission networks, power stations), costs and weather. Energy demands are given for industrial, commercial, and residential sectors for heating and non-heating end-use. Energy system data is given to represent the electricity and natural gas transmission networks and local energy systems. Cost data includes fuel costs, operational costs of different technologies and carbon costs. Wind speed and solar irradiance are given as weather data inputs.

b. The CGEN+Energy Hubs Model

The CGEN+Energy Hubs Model performs multi-time period operational analysis of the combined electricity and natural gas transmission networks, and Energy Hubs. At the transmission level, gas supply and electricity generation meet demands from large industrial consumers and energy flows into the Energy Hubs. Energy Hubs utilise regionally distributed energy resources, storage, and transmission energy supply to meet residential and commercial energy demands.

The CGEN+Energy Hubs Model minimises the total operating costs to meet energy demands over the operational time horizon. The total operating costs are derived for energy supplies at the transmission level and Energy Hubs, carbon costs and unserved energy. Constraints are derived from the operational characteristics of the combined natural gas and electricity transmission networks, and Energy Hubs.

The optimisation problem of the CGEN+Energy Hubs Model was developed and solved using the Fico Xpress optimisation suite. The Xpress-Sequential Linear Programming (SLP) solver for non-linear programming was used to minimise the objective function over the entire time horizon. The inbuilt Xpress SLP solver has been used for different complex non-linear problems developed based on the CGEN model (Chaudry et al., 2014b; Qadrdan et al., 2017a, 2016, 2015b, 2015c). Therefore, the same solver and optimisation programme was used for the development of the CGEN+Energy Hubs Model since this is an extension of the established CGEN model. The efficacy of other solvers was not considered within the scope of this research.

c. Model outputs

Key outputs from the CGEN+Energy Hubs Model include the energy supply mix at both transmission and distribution, total emissions, and operating costs. The model outputs are read into a Microsoft Power BI dashboard to allow the users to investigate model outputs. An example from the output dashboard is shown in Figure 6.6.

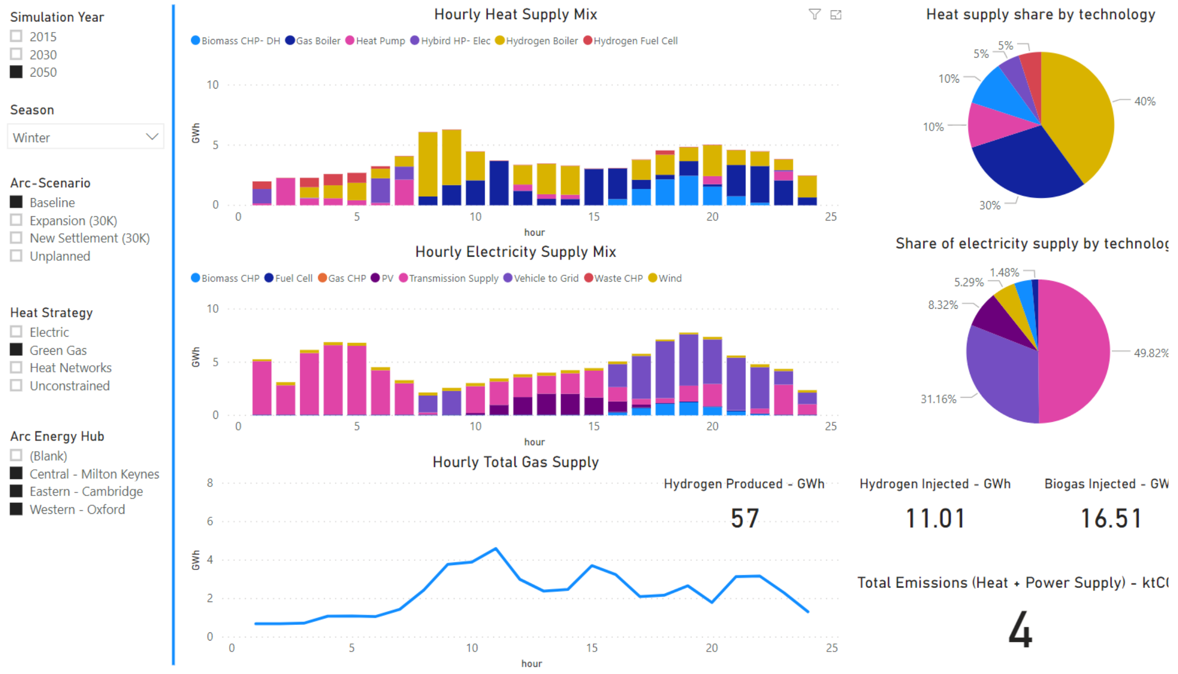

Figure 6.6 – Interactive model output dashboard showing hourly results for electricity, heat and gas supply given the simulation year, scenario, strategy, and Energy Hub

6.4.2. The objective function

The objective of the CGEN+Energy Hubs Model is to minimise the total operating costs of gas supply $\left(C_t^{gas,tran}\right)$ and electricity supply $\left(C_t^{elec,tran}\right)$ at the transmission level, energy supply in Energy Hubs $\left(C_{i,t}^{eh}\right)$, and carbon costs $\left(C_t^{carbon}\right)$ over the operational time horizon. The objective function is given by Equation 6.9.

$$Objective = min \sum_t \left\{ \underbrace{C_t^{elec,tran}}_{\textbf{(A)}} + \underbrace{C_t^{gas,tran}}_{\textbf{(B)}} + \underbrace{\sum_{i=1}^{29} C_{i,t}^{eh}}_{\textbf{(C)}} + \underbrace{C_t^{carbon}}_{\textbf{(D)}} \right\} \tag{6.9}$$

(A). The cost of electricity supply at the transmission level is modelled by Equation 6.10.

$$C_t^{elec,tran} = \underbrace{\sum_k C_k^{gen} P_{k,t}}_{\textbf{(i)}} + \underbrace{\sum_i \left(C_i^{imp} \times P_{i,t}^{imp} - C_{i,t}^{elec,sp} \times P_{i,t}^{exp}\right)}_{\textbf{(ii)}} + \underbrace{\sum_b C^{ue} P_{b,t}^{ue}}_{\textbf{(iii)}} \tag{6.10}$$

where,

i. power generation costs C_k^{gen} include fuel costs, operational and maintenance costs of power generator k (excluding interconnectors) for generating a unit of electricity. This unit cost was used to calculate the total costs of producing power $P_{k,t}$.

ii. costs of importing power $P_{i,t}^{imp}$ for a unit price C_i^{imp} and the revenues from exporting power $P_{i,t}^{exp}$ for a unit price $C_{i,t}^{elec,sp}$ via an interconnector link i.

iii. cost of unserved electricity demand calculated using the unserved electricity demand $P_{b,t}^{ue}$ at electricity busbar b with a penalty cost C^{ue}.

(B). The cost of natural gas supply at the transmission level is modelled by Equation 6.11.

$$\begin{aligned} C_t^{Gas\,Tran} = & \underbrace{\sum_a C_{a,t}^{gas} Q_{a,t}^{sup}}_{\text{(i)}} + \underbrace{\sum_k C_k^{res} Q_{k,t}^{res}}_{\text{(ii)}} + \underbrace{\sum_u \{C_u^w Q_{u,t}^w + C_u^i Q_{u,t}^i\}}_{\text{(iii)}} \\ & + \underbrace{\sum_m C_t^{gas,sp} \partial LP_{m,t}}_{\text{(iv)}} + \underbrace{\sum_n C^{ug} Q_{n,t}^{ug}}_{\text{(v)}} \end{aligned} \tag{6.11}$$

where,

i. The cost of gas supply from terminal a at time t was calculated by the volume of gas supplied $Q_{a,t}^{sup}$ and gas price $C_{a,t}^{gas}$.

ii. The costs of purchasing natural gas volume $Q_{k,t}^{res}$ from origin resource k, for a gas price of C_k^{res}.

iii. The cost of operating a gas storage facility u was calculated by the gas volume injected $Q_{u,t}^i$ or withdrawn $Q_{u,t}^w$ and the cost of gas injection C_u^i or withdraw C_u^w.

iv. The cost of change in linepack $\partial LP_{m,t}$ of pipe m at time t was calculated using the spot gas price $C_t^{gas,sp}$ at time t.

v. The cost of unserved gas demand was calculated using the unserved gas demand $Q_{n,t}^{ug}$ at gas node n at time t with a penalty cost C^{ug}.

(C). The cost of energy supply in the Energy Hub k is modelled by Equation 6.12.

$$\begin{aligned} C_{k,t}^{eh} = & \underbrace{\left\{ \sum_i^{\{Tech\}} E_{output,t}^i \times C^{i,f\&v} \right\} + \left\{ \sum_j^{\{bio,w\}} E_{j,t} \times C_j^{fuel} \right\}}_{\text{(i)}} \\ & + \underbrace{\{C^{ug} \times E_{g,t}^{ug} + C^{ue} \times E_{e,t}^{ue}\}}_{\text{(ii)}} \end{aligned} \tag{6.12}$$

where,

i. operating costs of distributed technologies include fixed and variable costs $\left(C^{i,f\&v}\right)$ of operating technology (i) with respect to energy outputs $\left(E_{output,t}^i\right)$, and fuel costs for biomass $\left(C_{bio}^{fuel}\right)$ and solid waste $\left(C_w^{fuel}\right)$.

ii. penalty costs (C^{ue}, C^{ug}) applied for unserved electrical $\left(E_{e,t}^{ue}\right)$ and natural gas $\left(E_{g,t}^{ug}\right)$ energy demand within the Energy Hub.

(D). The cost of CO_2e emissions is modelled by Equation 6.13.

$$C_t^{carbon} = \left(Em_t^{tran,powerGen} + Em_t^{tran,ind} + Em_t^{eh}\right) \times C^{carbon} \tag{6.13}$$

Carbon costs $\left(C^{carbon}\right)$ were calculated for the equivalent CO_2e emissions emitted at the transmission level from electricity generation $\left(Em_t^{tran,powerGen}\right)$ and fossil fuel consumed by large industrial consumers $\left(Em_t^{tran,ind}\right)$. Emissions of CO_2e from the Energy Hubs $\left(Em_t^{eh}\right)$ are calculated for the end-use fuel demand for electricity generation, heat supply, hydrogen supply and non-heating use.

Emissions of CO_2e from power generation at transmission level was modelled using Equation 6.14.

$$Em_t^{tran,powerGen}(tCO_2e) = \sum_{j}^{\{fuel\}} \sum_{j_k}^{\{powerGen\}} \frac{P_{j_k,t}}{\eta_k} \times Ef_j \tag{6.14}$$

where $\{fuel\}$= {natural gas, coal, oil, biomass}, $\{PowerGen\}$ = {natural gas-fired generators, oil-fired generators, coal-fired generators, biomass fired generators}, η_k is the efficiency of generation technology and Ef_j is the emissions factor given the gross calorific value basis for a unit of fuel (tCO_2e/MWh).

Equation 6.15 models the emissions of CO_2e from fossil fuels (j) consumed by large industrial consumers at each gas node n $\left(E_{n,j,t}^{tran,ind}\right)$.

$$Em_t^{tran,ind}(tCO_2e) = \sum_{j}^{\{fuel\}} \sum_{n}^{N} E_{n,j,t}^{tran,ind} \times Ef_j \tag{6.15}$$

Here, Ef_j is the emission factor for different fossil fuels.

6.4.3. Constraints

The constraints for the objective function are derived from the operational characteristics of the combined gas and electricity transmission networks, and Energy Hubs.

a. <u>The constraints from operating the natural gas transmission system are:</u>

- Gas supply from reception terminals, gas storage facilities and linepack in the pipelines are equal to the gas demand for large industrial consumers, power generation and gas flows into the Energy Hubs.
- The gas supplies into the reception terminals are subjected to the availability of gas resources such as LNG, UKCS production and pipeline imports.

- The gas flow within pipes satisfies the gas flow equation and determines nodal pressures at both ends of a pipeline. The gas flow is kept within the maximum gas flow capacity of each pipeline. The nodal pressure levels are kept within the operating pressure limits.
- The operation of a gas compressor station is limited within the maximum and minimum power requirement of the prime movers, and the overall compression ratio.
- The stored gas volume is balanced with gas volume withdrawn and gas volume injected from each gas storage facility.

b. <u>The constraints from operating the electricity transmission system are:</u>

- Electricity generation from generation plants and interconnector imports is equal to the electricity demand for industrial consumers, electricity flows into the Energy Hubs and exports.
- The power output from a generator is constrained by its rated capacity and for interconnectors, by the rated capacity of the interconnector link.
- The electricity output from wind and PV generators are variable with respect to input wind speed and solar irradiance at each busbar.
- The power flow in each transmission line is kept within the maximum power transfer capacity.
- The thermal power generators (CCGT, OCGT, coal and oil) adhere to the physical limits of ramping up/down and minimum start-up/shutdown times to balance the intermittency of wind and PV power generation.
- A minimum reserve level is set for thermal generators for contingencies such as unplanned power supply outages and variations in power supply and demand.
- The stored electrical energy is balanced with dispatched power and pump power of each pumped storage facility.
- The total cooling water withdrawn for cooling thermal power stations is constrained by the maximum water availability for the electricity sector at each busbar.

c. <u>The constraints from operating the Energy Hubs are:</u>

- Supply and demand are balanced for electrical, natural gas, heat and hydrogen energy within each Energy Hub.
- The electrical and gas energy supplies from the transmission networks are kept within the rated supply capacity of each gas offtake node and electricity busbar connected to the Energy Hub.
- The energy output from each technology type is kept within the rated output capacity.
- The electrical energy output from wind and PV plants are variable with respect to input wind speed and solar irradiance at each energy hub.
- Input and output energy conversion relationships are satisfied via energy efficiencies for each technology type.

- Heat and electrical energy outputs from combined heat and power technologies satisfy the heat to power ratio.
- Energy stored is balanced with input and output energy flows from each energy storage facility.
- The use of biomass and waste to energy technologies are constrained by the availability of biomass and solid waste fuels within the Energy Hub.

6.5. Integration of the CGEN+Energy Hubs Model into the National Infrastructure Systems Model (NISMOD)

The CGEN+Energy Hubs Model was integrated into the National Infrastructure Systems Model, NISMOD (ITRC, 2019b) to model energy supply infrastructure systems in GB. Recent reports (BEIS, 2020; CCC, 2019a; National Grid, 2020a) highlight the importance of combined analysis of energy systems and different interdependent sectors such as transport and water supply to develop coherent policy that meets stringent emission targets. Currently, these different sectors are analysed in isolation, and most energy system models are limited with soft linking capability with other sector models and provide a combined analysis.

Further developments were made to the CGEN+Energy Hubs Model within NISMOD to,

- use energy demand inputs from a National Energy Demand Model (Oxford).
- model energy demand for transport and vehicle to grid services using outputs from a National Transport Model (Southampton).
- model cooling water requirement for power generation using outputs from a National Water Supply Model (Oxford).

6.5.1. National Infrastructure Systems Model - NISMOD

NISMOD has been developed by the UK-Infrastructure Transitions Research Consortium (ITRC). The consortium is led by the University of Oxford, alongside Cardiff University, Newcastle University, University of Southampton, University of Cambridge, University of Leeds and University of Sussex.

NISMOD integrates engineering-based simulation models of Great Britain’s national infrastructure systems in the energy, transport, water, digital, and waste sectors. These models are linked through cross-sectoral demands for services, for example, electricity generation requires water and wastewater treatment requires electricity. Also, NISMOD includes a national infrastructure database and an infrastructure planning module. NISMOD is shown in Figure 6.7.

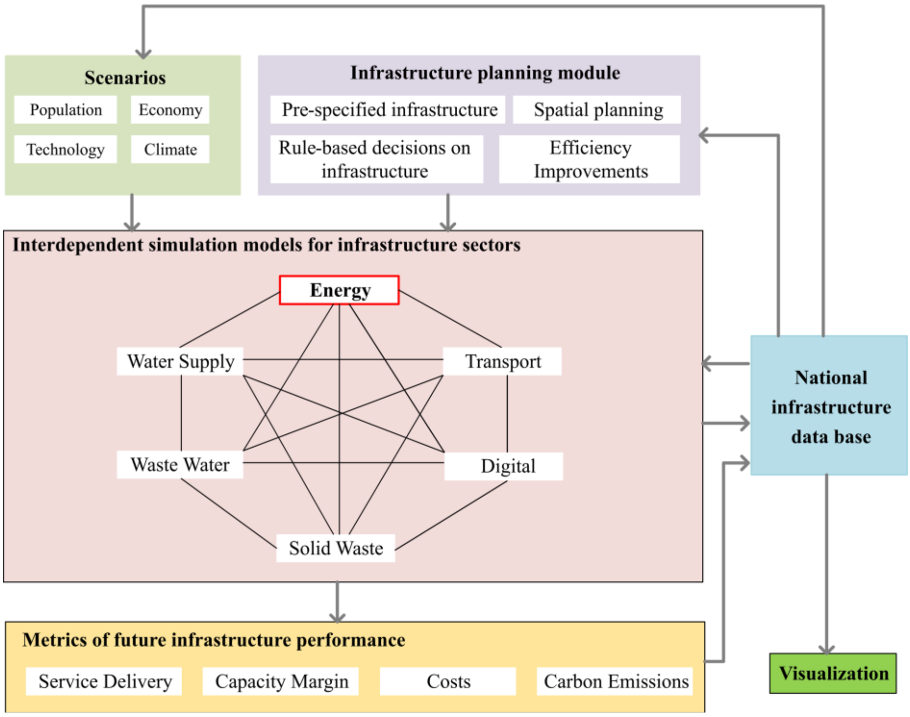

Figure 6.7 – National Infrastructure Systems Model (NISMOD)

Table 6.2 lists the models used in NISMOD to represent infrastructure systems across different sectors.

Table 6.2 – Infrastructure systems models used in NISMOD

Sector	Model	Developer/Citation
Energy	**CGEN+Energy Hubs Model**	(Jayasuriya et al., 2019)
	National Energy Demand model	(Eggimann et al., 2019)
Transport	National Transport model	(Lovrić et al., 2017a)
Water	National Water Supply model	(Ives et al., 2018)
Digital	Cambridge Digital Communications model	(Oughton et al., 2018)
Waste	Solid Waste Infrastructure model	(Roberts et al., 2018)

NISMOD uses scenarios of population, economics, urban development, technology, climate and hydrology to explore how the needs for infrastructure services might evolve in future. NISMOD allows the assessment of national cross-sectoral strategies for future infrastructure provision based on costs of services supply, carbon intensity and supply security (ITRC, 2019a).

6.5.2. Development of the CGEN+Energy Hubs Model within NISMOD

The CGEN+Energy Hubs Model was used in NISMOD to represent the national electricity and natural gas transmission systems and local energy systems. The CGEN+Energy Hubs Model was coupled to the National Energy Demand Model, National Transport Model and National Water Supply Model within NISMOD. Figure 6.8 shows detailed data flows between the models.

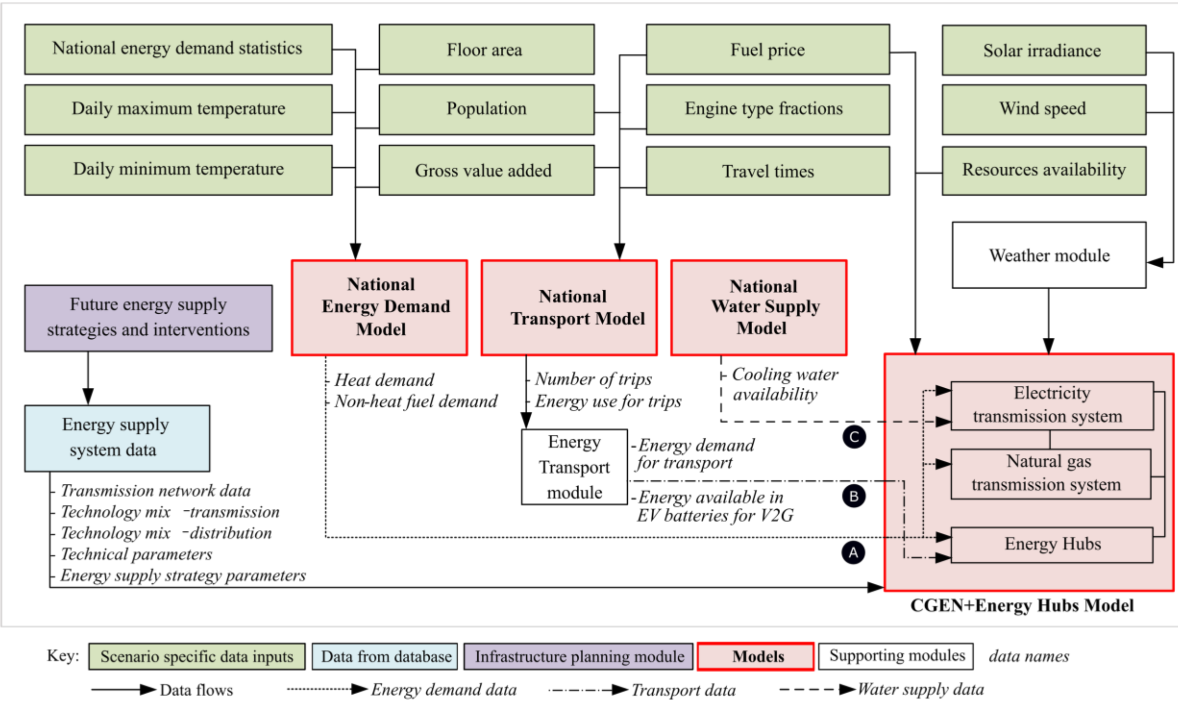

Figure 6.8 – Coupling between the CGEN+Energy Hubs Model, and National Energy Demand, National Transport and National Water Supply models within NISMOD

A. <u>Outputs from the National Energy Demand Model were used as inputs to the CGEN+Energy Hubs Model.</u>

The National Energy Demand Model (Eggimann et al., 2019) simulates future energy demand relative to a base year (2015), using population, floor area, GVA, technology uptake, climate change and behavioural change as inputs. Energy demands are calculated for residential, commercial and industrial sectors for heating (e.g. space heating and hot water) and non-heating end-uses (e.g. lighting, cooking) within each Local Authority District area in the UK at hourly resolution.

First, residential, commercial, and industrial heating and non-heating end-use energy demands calculated for Local Authority Districts (LAD) within an energy hub geographic boundary were aggregated. Residential, commercial, and industrial energy demands were then assigned to each Energy Hub. From these demands, industrial electricity and gas demands were assigned to each electricity busbar and natural gas offtake node of the Energy Hub.

B. Outputs from the National Transport Model were used as inputs to the CGEN+Energy Hubs Model

The National Transport Model (Lovrić et al., 2017a) represents passenger and freight transport via highways, railways, airports, seaports and local transit networks. The National Transport Model predicts future demand for each mode of transport using an elasticity-based simulation approach. Fuel prices, population and change in the mix of vehicle fleet are used as inputs. The mix of the vehicle fleet is given as, for example, passenger cars in 2030 from the total are 50% battery-electric vehicles, 30% plugin hybrid electric vehicles and 20% internal combustion engine cars.

The National Transport Model calculates the number of trips by vehicle type (e.g. battery electric vehicles, hydrogen fuel cell cars) and energy used for each trip by fuel (petrol, diesel, electricity and hydrogen). The calculations are made for each Local Authority District in the UK for hourly resolution. These outputs for Local Authority District areas within energy hub geographic boundaries were aggregated for input into the CGEN+Energy Hubs Model.

The number of electric vehicle trips and electricity use for each trip was used in the Energy Hubs to calculate the electrical energy available within EV batteries for vehicle to grid services at a given time. The electricity use and hydrogen use in vehicle trips were used to estimate electricity and hydrogen demands for transport in the Energy Hubs.

C. Outputs from the National Water Supply model were used as inputs to the CGEN+Energy Hubs Model.

The National Water Supply Model (Ives et al., 2018) simulates the sources of water supplies and moves water around a water network over time. The National Water Supply Model estimates water demand and water availability in rivers and groundwater. Freshwater available to withdraw for the electricity sector at each electricity transmission network busbar is provided as input to the CGEN+Energy Hubs Model.

Freshwater available to withdraw at each busbar was used as a constraint to the electricity generation from large power stations at the transmission level. The CGEN+Energy Hubs Model calculates the total consumption of the withdrawn freshwater (evaporated and used within the plant) with respect to the electricity generated and cooling method used.

Table 6.3 summarises different cooling methods used in the generation plant.

Table 6.3 – Different cooling methods used in power generation plant

Cooling method (y)	Description
Open-loop (once-through cooling)	This method runs a large amount of water through condensers in a single pass to absorb heat and discharge back to the local water source. Cooling water is withdrawn from the local water source for each cycle of cooling.

Closed-loop (evaporative cooling)	Cooling water is re-circulated in a loop through condensers. Warm water is exposed to ambient air using cooling towers. Cooling water is withdrawn from the water source only to replace water that is lost through evaporation in the cooling tower.
Air cooling (dry cooling)	Heat is removed by circulating forced air drafts via fans. This setup operates without cooling water.
Hybrid cooling	Combines air cooling and closed-loop cooling systems. It was assumed that from the overall cooling process 35% is air cooling and 65% closed-loop cooling (Macknick et al., 2012).

Table 6.4 summarises the cooling water withdrawal and consumption for a unit of electricity generated using different cooling methods.

Table 6.4 – Cooling water withdrawal and consumption rates by generation technology and by the cooling method (Byers et al., 2016; Macknick et al., 2012)

Technology (T)	Closed-loop (m^3/MWh)		Open-loop (m^3/MWh)		Hybrid (m^3/MWh)	
	Withdrawal	Consumption	Withdrawal	Consumption	Withdrawal	Consumption
CCGT	0.958	0.749	43.073	0.379	0.59	0.47
CCGT with CCS	1.877	1.431	53.841	0.575	1.19	0.880
Coal	3.804	3.565	137.585	0.946	1.33	1.17
Nuclear	4.167	2.544	167.865	1.018	2.52	1.71
Dedicated waste/biomass	3.32	2.69	132.48	0.95	2.15	1.75
Gas CHP	0.58	0.47	25.84	0.23	0.38	0.31

In the CGEN+Energy Hubs Model, each generation plant connected to the transmission network was characterised by the generation technology, cooling method and the cooling water source (e.g. freshwater and seawater). A complete list of generation plants is given in Appendix B.

<u>(i). Modelling of cooling water requirement for power generation</u>

The total volume of water withdrawn for cooling generation plants connected to busbar b at time t $\left(W_{b,t}^{withdraw}\right)$ was modelled by Equation 6.16.

$$W_{b,t}^{withdraw} = \sum_{k}^{\{generators\}} P_{k,t} \times W_{k,T,y}^{withdraw} \tag{6.16}$$

Here, $W_{k,T,y}^{withdraw}$ is the rate of water withdrawal given by the generation technology T and cooling method y of generation plant k.

The total cooling water withdrawn is constrained by the maximum water availability for the electricity sector at busbar b $\left(W_b^{available,max}\right)$ as shown in Equation 6.17.

$$W_{b,t}^{withdraw} \leq W_b^{available,max} \tag{6.17}$$

(ii). Modelling of cooling water consumed by power stations

The total cooling water volume consumed by generation plants at busbar b at time t $\left(W_{b,t}^{consume}\right)$ was modelled by Equation 6.18.

$$W_{b,t}^{consume} = \sum_{k}^{\{generators\}} P_{k,t} \times W_{k,T,y}^{consume} \tag{6.18}$$

Here, $W_{k,T,y}^{consume}$ is the cooling water consumption rate given by the generation technology T and cooling method y of generation plant k.

6.6. Summary

Geographic regions were defined to model Energy Hubs that represent local energy systems in GB. These Energy Hubs were integrated into the CGEN model via electricity busbars and gas offtake nodes in the transmission networks.

The CGEN+Energy Hubs Model was developed by extending the optimisation model of CGEN to include energy hub operating costs and constraints. The CGEN+Energy Hubs Model minimises the total operating costs of energy resources supply, transmission, distribution, and carbon costs to meet energy demands. The constraints are derived from the operational characteristics of the transmission networks and Energy Hubs.

The CGEN+Energy Hubs Model was integrated into the National Infrastructure Systems Model (NISMOD). Further developments were made to the CGEN+Energy Hubs Model by integrating with the National Energy Demand Model, National Transport Model and National Water Supply Model within NISMOD. Energy demands including the demand for transport, vehicle to grid services and cooling water availability constraints for power generation plants were modelled.

The new CGEN+Energy Hubs model address the limitations of modelling and analysing dispersed local energy system alongside the backbone gas and electricity transmission networks. In addition, the CGEN+Energy Hubs model is capable of soft linking interdependent sector models such as transport and water supply and providing analysis of policies that are coherent across such different sectors.

7. A case study of future low-carbon energy supply strategies for the Oxford-Cambridge Arc region

7.1. Introduction

The CGEN+Energy Hubs Model was used to perform a case study on low-carbon energy supply strategies for the Oxford-Cambridge Arc region. The Energy Supply Strategies were defined by heat supply, using (1) low-carbon electricity, (2) heat networks, and (3) green gases (hydrogen and biogas). The study assessed how these Energy Supply Strategies could affordably reduce CO_2 emissions from the Oxford-Cambridge Arc's energy system.

The developments made to the CGEN+Energy Hubs Model by integrating the National Energy Demand Model and the National Transport Model were used for this case study. The developments made with the National Water Supply Model was not included in this case study, as the scenarios are rather focused on energy-transport interactions only. The national models were used for the analyses, however, the modelling and results presented in this chapter focuses only on the Oxford-Cambridge Arc region.

7.2. The Oxford-Cambridge Arc region

The Oxford-Cambridge Arc region, as shown in Figure 7.1, consists of four county councils (Buckinghamshire, Cambridgeshire, Northamptonshire, and Oxfordshire), 26 district councils and unitary authorities, and the combined authority of Cambridgeshire and Peterborough. The region is home to 3.7million people, around 2 million jobs and contributes over £110 billion of annual Gross Value Added (GVA) to the UK economy per year (NIC, 2017).

Figure 7.1 – The Oxford - Cambridge Arc region

Future growth of the Oxford-Cambridge Arc region will add one million new homes (additional) across the region by 2050, an East-West expressway road, and require major improvements to the East-West rail routes connecting Oxford, Milton Keynes and Cambridge (Ministry of Housing Communities and Local Government, 2019; NIC, 2017). This case study used four contrasting scenarios to describe the future development of the region in terms of population growth, construction of additional dwellings and expansion of transport links. Table 7.1 summarises the growth scenarios used in the case study.

Table 7.1 – Summary of the scenarios used to describe the growth of the Oxford-Cambridge Arc region (ITRC, 2020)

Arc Scenario	Scenario description					
	Additional dwellings per annum	Total population by 2050 (millions)	Total dwelling floor area by 2050 (km^2)	Gross Value Added (GVA) per annum by 2050 (£ Billion)	Spatial development of housing	Development in Transport links
1. Baseline	14,500	4.3	157.6	139	No new settlements are developed.	No new major transport links are developed.
2. Unplanned	19,000	4.6	170.1	176.6	Ad-hoc development within the region with market-driven responses to housing needs.	Both the Expressway and the East-West rail link are developed
3. New Settlement	30,000	6.1	202.6	226.9	A string of 5 new smaller cities is developed along the main transport corridor of the Arc region.	

4. Expansion	30,000	5.3	196.1	226.8	Expansion of existing urban developments centred around Oxford, Milton Keynes, and Cambridge.	

7.3. Energy Supply Strategies

Energy Supply Strategies describe specific supply-side technologies, networks, and end-use technologies to meet energy demands within each Arc Scenario. The Energy Supply Strategies were based on options for low-carbon heat supply. These are,

1) **Electric** Strategy: Heating is electrified using low-carbon electricity.
2) **Heat Networks** Strategy: Biomass and waste fuelled combined heat and power units are used in district heating networks.
3) **Green Gas** Strategy: Hydrogen and biogas are used for heating, and
4) **Unconstrained** Strategy: A specific heat supply method is not defined in this strategy, but the CGEN+Energy Hubs Model chooses a combination of heating technologies to minimise operating costs.

The technology uptake across the Energy Supply Strategies was determined considering maturity and annual build rates of technologies (CCC, 2019a; Chaudry et al., 2015; ETI, 2013; National Grid, 2019a). In addition, the installed capacities were subjected to a capacity margin of 10% (de-rated) considering annual and peak heat demands in each Arc Scenario. Table 7.2 shows a summary of the Energy Supply Strategies out to the year 2050.

Table 7.2 – Summary of the Energy Supply Strategies (2050)

Energy supply sectors in the Arc Energy Hubs	**Energy Supply Strategies**			
	1). Electric	**2). Heat Networks**	**3). Green Gas**	**4). Unconstrained**
Heat	• Heat is supplied completely by electricity using heat pumps, resistive heating, and electric boilers.	• The heat supply is mainly from Combined Heat and Power (CHP) driven district heating networks. CHP units use natural gas, biomass, and solid waste as fuels. • The availability of biomass and solid waste for heating is restricted within the region.	• Heat supplies are mainly from building level hydrogen boilers. • Homes without hydrogen supplies use gas boilers, heat pumps or are connected to a district heating network (via biomass/biogas CHP units). • Gas boilers produce low-carbon heat as biogas and	• The model was free to select **any heating technology** modelled to meet demand at the **lowest operational costs** whilst adhering to physical constraints. • The availability of biomass and solid waste for heating is restricted within the region.

		• Gas boilers are used in the district heating systems to supplement CHP units during peak periods. • Homes without a heat network connection continue to use gas boilers or use heat pumps.	hydrogen are injected into the gas mix.	
Electricity	• Distributed generation is mainly from wind, solar PV and vehicle to grid services. • Backup gas-fired generators are installed to compensate for the variability in wind and PV generation. • CHP units in district heating applications supply electricity as they produce heat (heat demand-driven CHP operation is assumed).			
Gas	• Transmission grid supplies are available with limited gas storage facilities within the arc region.		• Hydrogen and biogas injection into the gas grid is limited to 20% by volume. • Large scale hydrogen production via Steam Methane Reforming (SMR) with Carbon Capture and Storage (CCS) is assumed. Small-scale hydrogen production is via electrolysis. • Hydrogen is supplied via new hydrogen pipelines and re-purposed gas distribution pipes. • Anaerobic digestion plants are used to produce biogas.	• Transmission grid supplies are available with limited gas storage facilities within the arc region.

For clarification, different combinations of the Arc Scenarios across Energy Supply Strategies are presented in Figure 7.2.

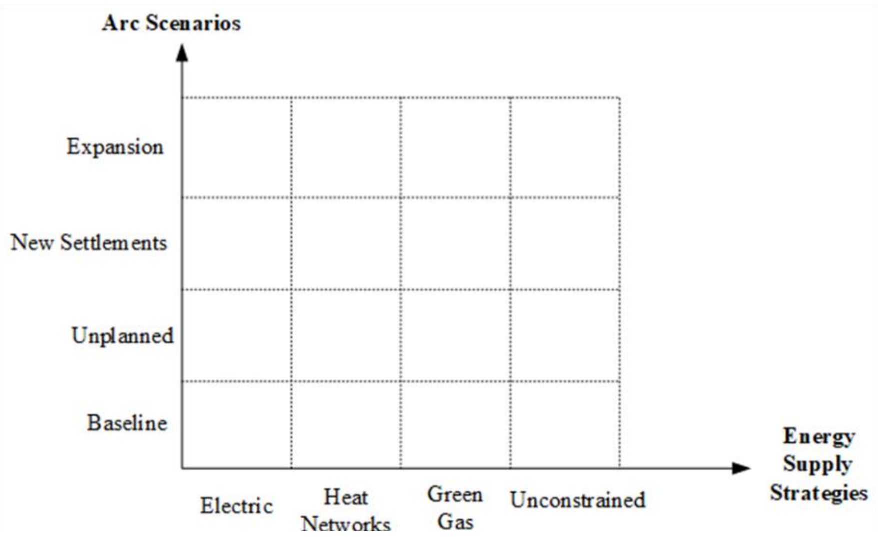

Figure 7.2 – Different combinations of the Arc Scenarios across Energy Supply Strategies

7.4. Modelling of the Oxford-Cambridge Arc energy system

7.4.1. Spatial modelling

Spatial modelling of the Oxford-Cambridge Arc region used the energy hub geographic regions in the CGEN+Energy Hubs Model. In Figure 7.3, the grey areas represent the energy hub geographic regions in the CGEN+Energy Hubs model. Three of these energy hub geographic regions (yellow area), 21-Western Oxford, 22-Central-Milton Keynes, and 24-Eastern-Cambridge were used to represent the Arc region. The list of Local Authority Districts within each arc energy hub region is given in Figure 7.3.

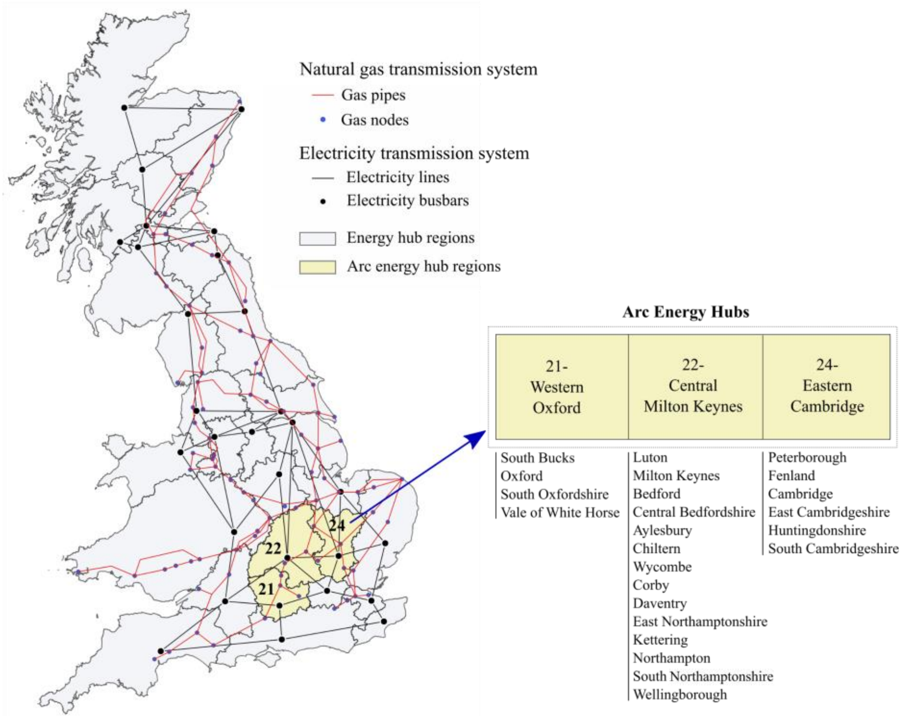

Figure 7.3 – Representation of the Arc region using the Energy hub geographic regions in the CGEN+Energy Hubs Model

7.4.2. Energy demands and energy supply capacity calculations

a. <u>Energy demand calculation.</u>

Energy demands were calculated using the assumptions (ITRC, 2020) for population, GVA and dwelling floor areas across all Arc Scenarios. These high-level assumptions were used in the National Energy Demand Model (Eggimann et al., 2019) and the National Transport Model (Lovrić et al., 2017b). The models were run to calculate heat, non-heating and transport electricity demands for GB out to the year 2050.

Figure 7.4 shows the annual heat and non-heat demand within the Arc region for the Arc Scenarios in the year 2050. The overall demand for heating is projected to decline in 2050 from 2015 across all Arc

Scenarios due to ambitious 25% savings from improved insulation, thermal comfort in the building stock and a 100% smart meter rollout across the Arc region.

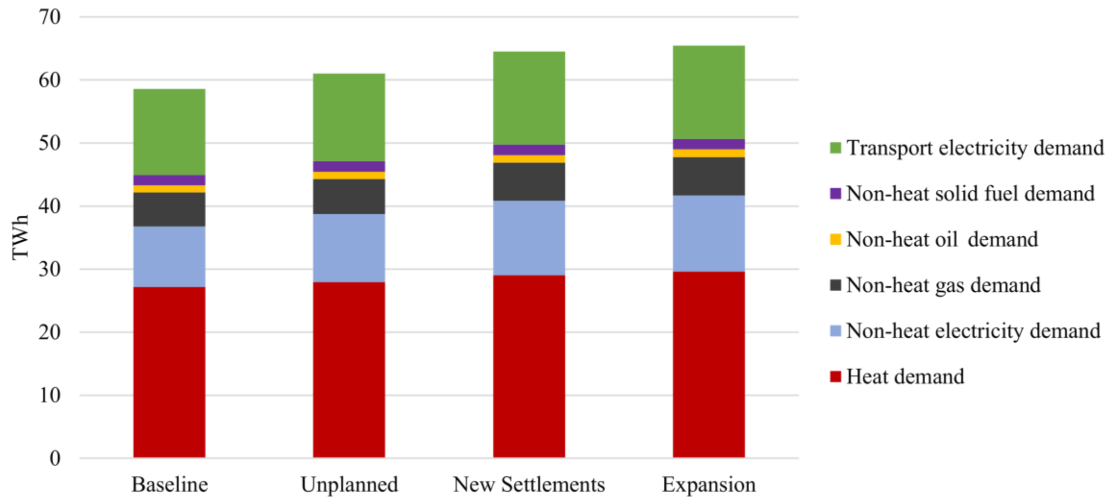

Figure 7.4 – Annual heat and non-heat demand for the year 2050 across the Arc Scenarios

b. <u>Energy supply capacity calculation</u>

The energy supply capacity of the Energy Hubs that represent the Arc region were calculated based on the regional data published by National Grid for their Two Degrees Scenario (National Grid, 2019a). These regional capacity data were sized to ensure that energy demands could be met across all Arc Scenarios and according to the Energy Supply Strategy selected. These calculations also took account of a capacity margin of 10% (Royal Academy of Engineering, 2013). Table 7.3 shows the calculated electricity generation capacity within the Arc region for the Baseline Scenario.

The energy supply capacity calculated for the rest of the GB is given in Appendix C.1.

Table 7.3 – Installed electricity generation capacities within the three Arc Energy Hubs in 2015 and for the Baseline Scenario in 2050.

Generation type	**Electricity generation capacity (MW_e)**				
	2015	**Baseline Scenario - 2050**			
		Electric	**Heat Networks**	**Green Gas**	**Unconstrained**
Gas (non-CHP)	131	366	366	366	366
Onshore wind	141	348	348	348	348
PV	2547	8644	8644	8644	8644
Gas CHP	465	391	391	391	391
Biomass CHP	7	267	739	267	739
Waste CHP	68	130	739	296	739
Fuel cells	0	0	0	148	148
Vehicle to grid	0	2453	2204	1760	2547
Transmission supply capacity	3333	6176	3542	3333	4270
Total Capacity	*6692*	*18775*	*16970*	*15553*	*18192*

For the Baseline Scenario, Table 7.4 shows the calculated heat supply capacity within the Arc region.

Table 7.4 - Installed heat supply capacities within the Arc Energy Hubs in 2015 and for the Baseline Scenario in 2050.

Technology	Installation	Heat supply capacity (MW_{th})				
		2015	Baseline Scenario – 2050			
			Electric	Heat Networks	Green Gas	Unconstrained
Air source heat pumps	Building level	25	1725	690	345	1725
Gas boilers		4018		173	1035	1035
Electric boiler			388			388
Resistive heaters		502	518			518
Hydrogen boiler					1553	1553
Hybrid heat pump			970		194	970
Oil boiler		594				
Gas CHP	District heating network	3		582		582
Biomass CHP		6		1109	444	444
Waste CHP				1109		260
Gas boiler		3		388		388
Hydrogen fuel cell					222	222
Total Capacity		*5151*	*3601*	*4051*	*3793*	*8085*

7.4.3. Simulation

The calculated energy demands, and energy supply capacity data flows for the simulation of the CGEN+Energy Hubs model is shown in Figure 7.5.

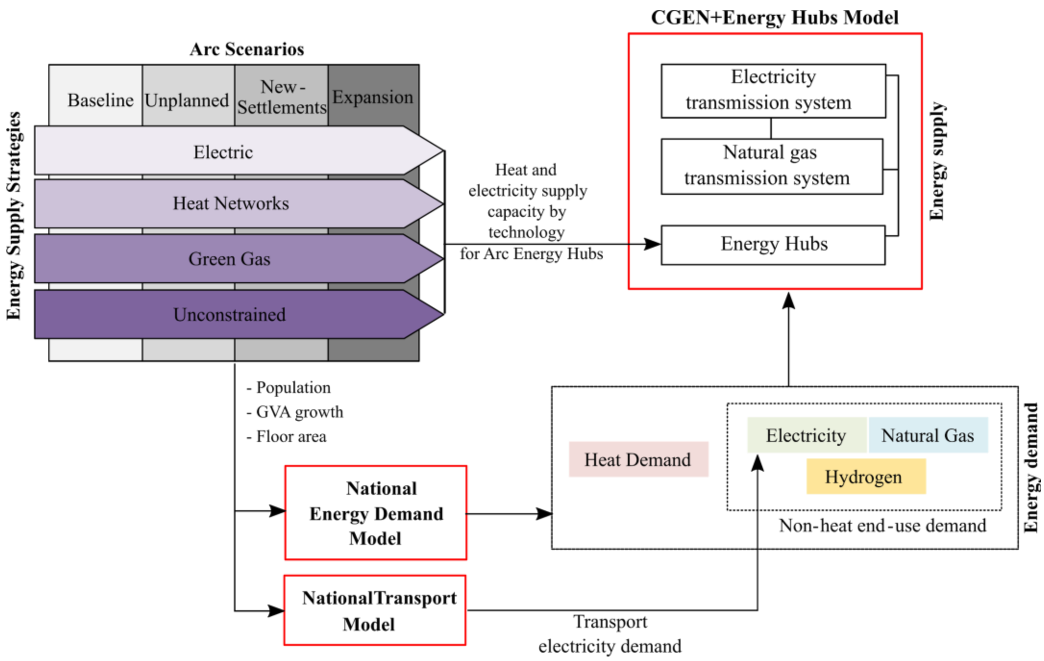

Figure 7.5 – Data flows for the simulations performed using the CGEN+Energy Hubs model.

Simulations were performed using the CGEN+Energy Hubs Model for each Arc Scenario across all Energy Supply Strategies in 2015, 2030, and 2050. Each simulation year consisted of four seasons and each season was modelled by a representative week using hourly time granularity.

Within each simulation, the CGEN+Energy Hubs Model performed operational analysis of the entire GB energy system (transmission and all Energy Hubs as an integrated system). However, this case study focuses only on the three Energy Hubs that represent the energy system within the Oxford-Cambridge Arc region. The impact on key metrics such as electricity, gas and heat supply mix, emissions and costs for the Arc Energy Hubs were analysed.

7.5. Results of the simulations of the Arc's energy system

Energy supply, emissions, and costs (operational and planning) were determined for the Arc region across Arc Scenarios and Energy Supply Strategies in 2050. (see page 100, Figure 7.2 for all combinations for the Arc Scenarios and Energy Supply Strategies).

7.5.1. Energy supply

Figure 7.6 shows the annual energy supplies for the Arc Scenarios across Energy Supply Strategies. The annual energy supply meets the demands for heating and non-heating end-uses (including transport). The Expansion and New Settlements Scenarios show the highest annual use of energy. There is a difference of approximately 10TWh between the Expansion and Baseline Scenarios across all Energy Supply Strategies.

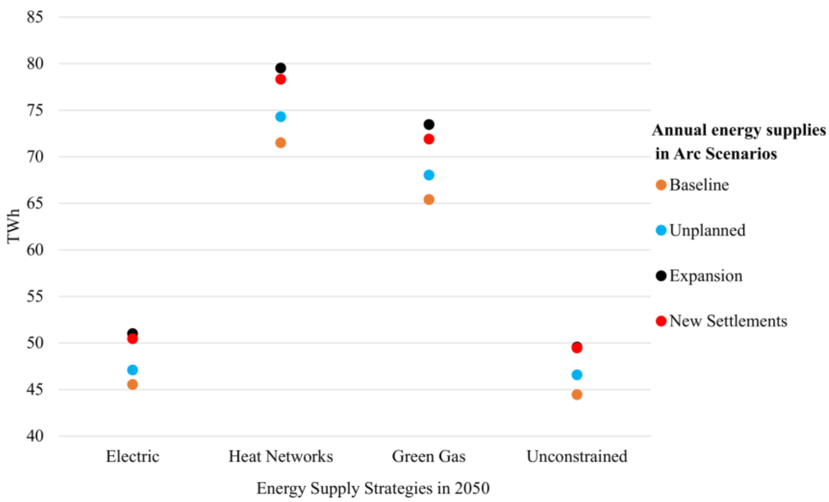

Figure 7.6 – Annual energy supplies for the Arc Scenarios in 2050 across Energy Supply Strategies

Figure 7.7 shows the annual energy supply by fuel in 2015 and for the Baseline Scenario in 2050 across the Energy Supply Strategies. These are the primary fuel supplies into the Arc Energy Hubs, which are converted (to heat, electricity and hydrogen) and stored within the region to meet demands for heating and non-heating end-uses.

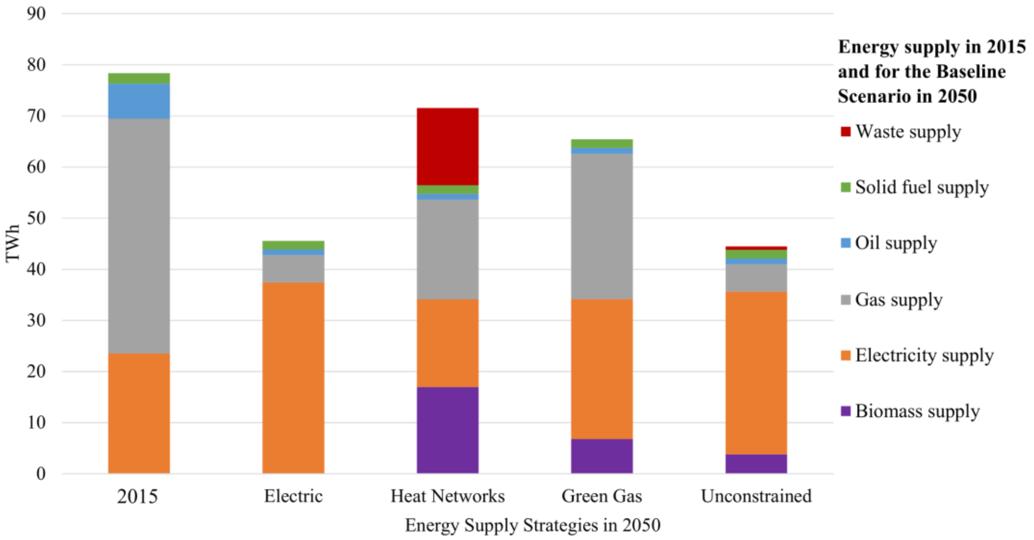

Figure 7.7 – Annual energy supply by fuel in 2015 and for the Baseline Scenario in 2050 across Energy Supply Strategies

Table 7.5 shows the energy supply by fuel as a share of the annual energy supplied for the Baseline Scenario in 2050.

Table 7.5 – Energy supply by fuel as a share of the annual energy supplied for the Baseline Scenario in 2050

Energy Supply Strategy	Share of the annual energy supplied (%)						Annual energy supply (TWh)
	Biomass	Electricity	Natural Gas	Oil	Solid fuel	Waste	
Full Electric	0.0	82.1	11.7	2.5	3.7	0.0	46
Heat Networks	23.7	24.0	27.2	1.6	2.3	21.1	72
Green Gas	10.4	41.9	43.5	1.7	2.6	0.0	65
Unconstrained	8.5	71.6	12.0	2.6	3.8	1.5	45

For the other Arc Scenarios, the energy supply by fuel as a share of the annual energy supplied is found to be similar to the Baseline Scenario.

In Electric and Unconstrained Strategies for all the Arc Scenarios, electricity is used for heating via heat pumps. The electricity supply required for heating (MWh_e) is significantly lower than the heat supplied (MWh_{th}) as the Coefficient of Performance (COP) is greater than one. Therefore, the annual energy supplies in the Electric and Unconstrained Strategies are shown as 30TWh less by 2050 on average across the Arc Scenarios compared to 2015. In contrast, annual energy supplies are shown as higher in Green Gas and Heat Networks Strategies because of less efficient production of heat using natural gas, hydrogen, biomass, and solid waste across all Arc Scenarios.

Figure 7.8. shows that the annual energy supplies per dwelling basis are lower in 2050 than in 2015 due to efficiency improvements in dwellings and end-use technologies.

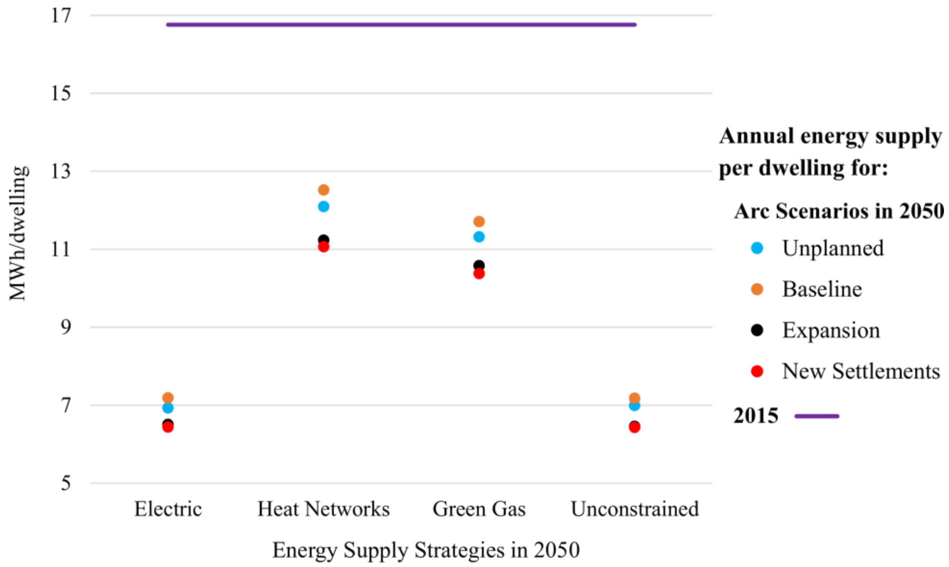

Figure 7.8 – Annual energy supply per dwelling in 2015 and for Arc Scenarios across Energy Supply Strategies in 2050

7.5.2. Heat supply

The Energy Supply Strategies showed different technology options used to meet the end-use heating demand for the Arc Scenario in 2050. Figure 7.9(a) shows the annual heat supplied by technology in 2015 and for the Expansion Scenario in 2050. For the same scenario, Figure 7.9(b) shows the annual input energy supplied for heating by fuel.

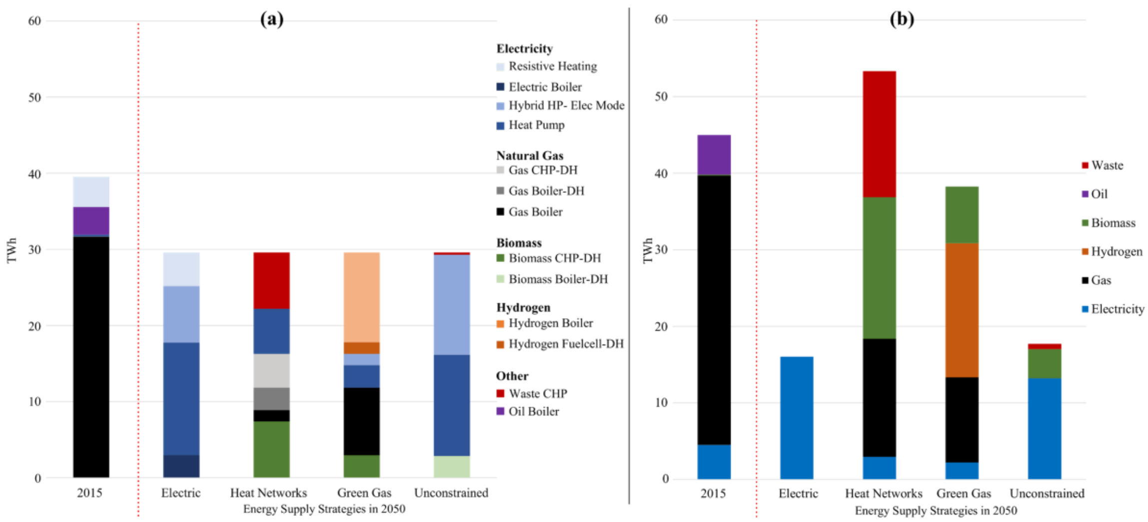

Figure 7.9 – (a) Annual heat supplied by technology and (b) annual input energy supplied for heating by fuel in 2015 and for the Expansion Scenario in 2050

In the Electric Strategy, all dwellings are equipped with heat pumps and/or resistive heating. Heat pumps (air source and hybrid heat pumps) supply 75% of the annual heating demand. The rest of the heat supply is by resistive heating and electric boilers and mostly used for hot water.

The Heat Networks Strategy in all Arc Scenarios uses CHP units connected to district heating networks. The CHP units use biomass, natural gas and municipal solid waste as input fuels. Natural gas boilers are used as a backup for the CHP units in the district heating networks. The district heating networks supply on average 70% of the annual heating demand within the region across all Arc Scenarios. The remainder of the heating demand for dwellings without a heat network connection is provided by gas boilers or heat pumps.

In the Green Gas Strategy, building-level hydrogen boilers and natural gas boilers supply 70% of the annual heating demand within the region. Biomass CHP units and hydrogen fuel cells connected to district heating networks provide 15% of the annual heat supply. Heat pumps are used in the dwellings without a gas network or a district heating network connection.

In the Unconstrained Strategy, all heating technologies are available to the Arc Energy Hubs. The technologies to meet the heating demand are chosen by minimising operational costs including fuel and carbon costs. The use of electric heating technologies results in the lowest costs for the three Arc Energy Hubs as electricity generation becomes predominately low carbon (both nationally and within the Arc region). Heat pumps and hybrid heat pumps account for almost 90% of the annual heating demand by 2050. The remaining 10% of the annual heating demand is met by biomass boilers and waste CHP units connected to heat networks due to lower carbon emissions compared with the use of natural gas-fuelled heating technologies.

7.5.3. Electricity supply

Figure 7.10 shows the annual electricity supply to meet the electricity demand for heating and non-heating end-uses within the Arc Scenarios. The annual electricity supply is the total of electricity supplied from distributed generators and the electricity imported from the transmission networks into the Arc region.

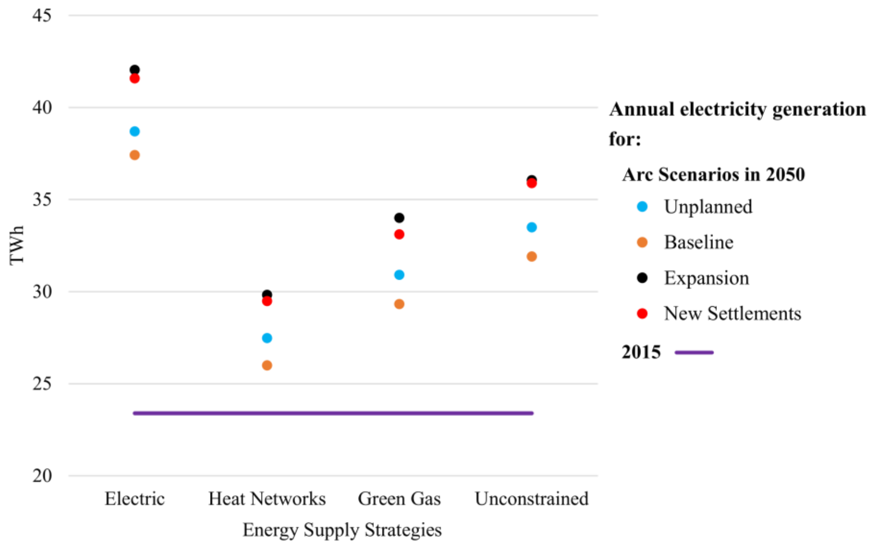

Figure 7.10 – The annual electricity supply for the Arc Scenarios across Energy Supply Strategies in 2050

The annual electricity supply in the Arc region is greater in 2050 than in 2015 for all Arc Scenarios. The highest increase in annual electricity supply is shown in the Expansion Scenario. This is a 22TWh increase in 2050 compared to 2015. The annual electricity supply increases the least in the Baseline Scenario due to low growth in population and new dwellings.

The Electric Strategy across all Arc Scenarios has the highest annual electricity supply to meet the electricity demand for heating via heat pumps and EV charging. The Heat Networks and Green Gas Strategies largely use natural gas, hydrogen, biomass and waste fuelled heating systems in preference to the use of heat pumps. Therefore, the annual electricity generation is lower compared to the Electric Strategy.

Figure 7.11(a) shows the annual electricity supplied by technology and electricity imported from the transmission network in 2015 and for the Expansion Scenario in 2050. For the same Scenario, Figure 7.11(b) shows the use of Vehicle-to-Grid electricity supply.

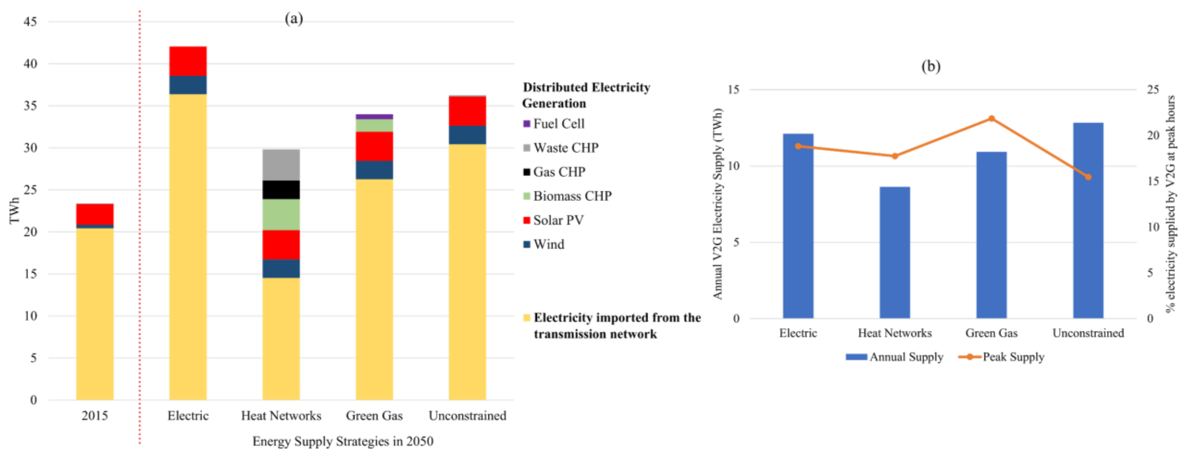

Figure 7.11 – (a) Annual electricity supplied by distributed generation and the electricity imported from the transmission network (includes a 2015 comparator), (b) the use of Vehicle to Grid electricity supply for the Expansion scenario in 2050

For the other Arc Scenarios, the types of distributed generation technologies used, and their share of the annual electricity supplied are found to be similar to the Expansion Scenario.

Electricity supply from Vehicle to Grid (V2) performs a significant role during the peak hours to balance the system. V2G electricity supply accounted for ~18% of the electricity supply during the peak hour and ~10TWh annually across all Arc Scenarios and Energy Supply Strategies.

Local wind and PV generators supply electricity to their maximum capacities (as long as the resource is available - wind and irradiance) and provide 15% of the annual electricity supply. No curtailment occurs in any of the Energy Supply Strategies.

In the Heat Networks Strategy, electricity is supplied from natural gas, biomass, and waste CHP units in addition to the electricity supply from Vehicle to Grid and renewables. The total electricity supplied locally contributes to 60% of the annual electricity supply in all Arc Scenarios. Consequently, there is a significant decline in electricity imported from the transmission network into the Arc region. The increase in local supply and the reduction of imports from the transmission network also aligns with the low electricity demands for heating as heat networks are deployed.

In all Energy Supply Strategies electricity imported from the transmission system remains vital to balance electricity supply and demand within the Arc region. As the national electricity system decarbonises with electricity generated from nuclear, offshore wind and PV, the additional use of non-renewable distributed generation is not cost-effective due to high carbon costs (99 £/tCO_2, (BEIS, 2018j)).

7.5.4. Natural gas supply

Figure 7.12 shows the annual natural gas supply for the Arc Scenarios across Energy Supply Strategies in 2050. The annual natural gas supply is the total of natural gas imported from the transmission network into the Arc region. The annual natural gas supply is lower across all Arc Scenarios in 2050 compared to 2015 (~45TWh).

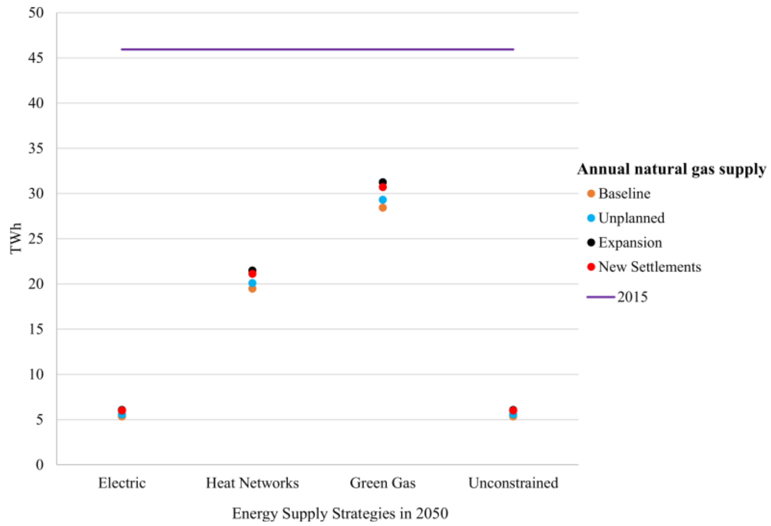

Figure 7.12 – Annual natural gas supply for the Arc Scenarios across Energy Supply Strategies in 2050

The annual natural gas supply is the lowest in the Electric and Unconstrained Strategies for all Arc Scenarios (almost 90% lower compared to 2015). In the Electric Strategy, the annual natural gas supply is lower due to electricity largely replacing natural gas for heating. In the Unconstrained Strategy, natural gas-fuelled heating systems are not used due to high carbon penalties.

The Heat Networks and Green Gas strategies show large annual natural gas supplies compared to the Electric and Unconstrained Strategies. The Green Gas Strategy shows the highest annual natural gas supply for all Arc Scenarios, as natural gas is largely used to produce hydrogen with Steam Methane Reformation in addition to heating in gas boilers. In the Heat Networks Strategy, natural gas is only used for heating in CHP units and gas boilers, and therefore has lower natural gas supplies compared to the Green Gas Strategy.

7.5.5. Hydrogen and biogas supply

Hydrogen is produced primarily from natural gas using Steam Methane Reformation (SMR) with carbon capture and storage (CCS). Also, hydrogen is produced by electrolysis using the excess renewable electricity from distributed wind and PV plants. The highest annual hydrogen production within the Arc region is 18TWh for the Expansion scenario in the Green Gas Strategy.

From the hydrogen produced, 7-8% is injected into the existing gas network to blend with natural gas (20% by volume) in all Arc Scenarios. The remaining hydrogen is supplied via re-purposed natural gas pipelines and newly built hydrogen pipelines. This dedicated hydrogen supply meets the hydrogen demand for heating in boilers and fuel cells and high-temperature industrial applications.

Biogas is produced by Anaerobic Digestion of organic waste within the Arc region. Biogas injected into the gas network is 5TWh on average across all Arc Scenarios for the Green Gas Strategy.

7.5.6. Emissions

The CO_2 emissions from electricity generation, heat supply, hydrogen production, and non-heating end-use of fossil fuels within the Arc region were calculated. The CO_2 emissions related to electricity imported from the transmission network are not included in the calculations, as these are mainly supplied carbon-free through generation from nuclear plants, offshore and onshore wind farms.

Figure 7.13 shows the annual CO_2 emissions calculated for the Arc Scenarios in 2050. The Arc Scenarios across all Energy Supply Strategies show lower annual CO_2 emissions compared to 2015 (11MtCO$_2$). Among the Arc Scenarios, the Expansion Scenario shows the highest and the Baseline Scenario shows the lowest annual CO_2 emissions.

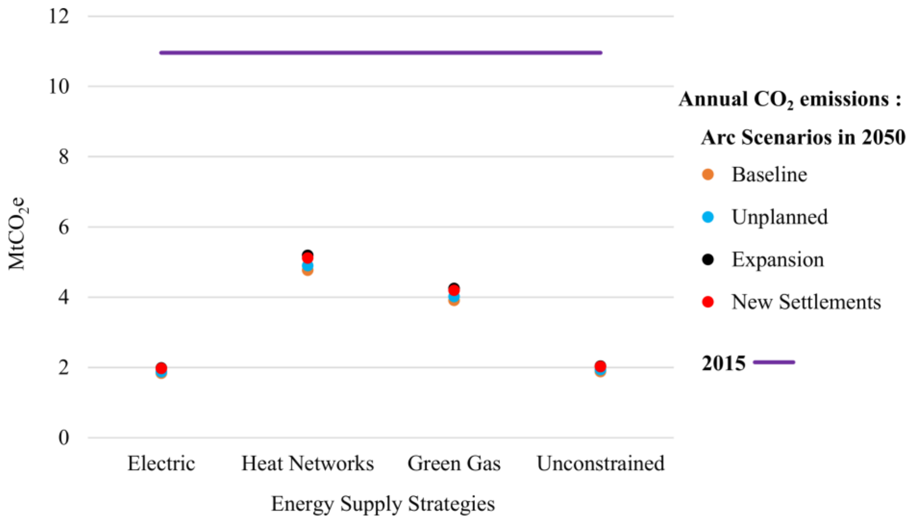

Figure 7.13 – Annual CO_2 emissions calculated for the Arc Scenarios across Energy Supply Strategies in 2050

The Electric and Unconstrained Strategies show the lowest annual emissions of 2MtCO_2 as low carbon electricity is used to meet more than 90% of the end-use demands. Most of the remaining annual emissions are from natural gas, oil, and solid fuel used for non-heating end-uses in the industrial sector.

The Heat Networks Strategy accounts for the highest annual emissions with an average of 5MtCO_2 across the Arc Scenarios. The annual CO_2 emissions are mainly from natural gas used in CHP units and boilers in addition to the non-renewable fuels used in the industry.

In the Green Gas Strategy, hydrogen and biomethane are used in place of natural gas for heating. Therefore, annual emissions are approximately 1MtCO_2 lower than the Heat Networks Strategy. Hydrogen is mainly produced by using natural gas via Steam Methane Reformation with 95% of CO_2 captured in the process.

7.5.7. Total costs of implementing the Energy Supply Strategies

The total annualised costs of implementing the Energy Supply Strategies were calculated for each Arc Scenario. These include operating and investment costs within the Arc Energy Hubs.

a. Operating costs

The operating costs of the Arc Energy Hubs consist of,

a) variable operating costs of distributed technologies, including fuel costs for biomass and waste, and carbon costs (excluding the costs in (b) and (c) below). These are calculated within the model objective function.
b) natural gas imported from the transmission network.
c) electricity imported from the transmission network.

Figure 7.14 shows the total operating costs for the Baseline Scenario across Energy Supply Strategies.

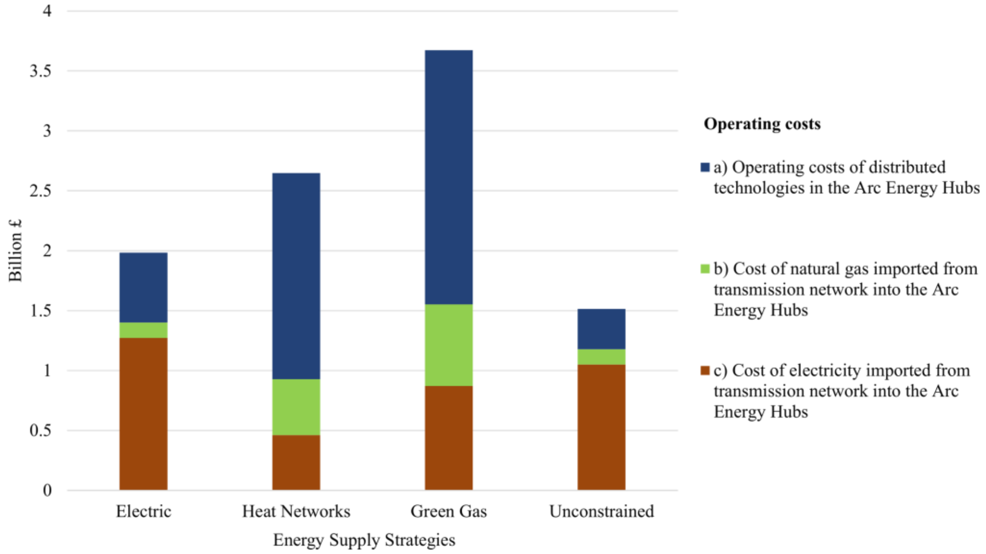

Figure 7.14 – The total operating costs for the Baseline Scenario across Energy Supply Strategies in 2050.

The Green Gas Strategy shows the highest total operating costs. This is due to high volumes and hence costs associated with natural gas and biomass, in addition to the costs of producing hydrogen by Steam Methane Reformation. All renewables are fully utilised to support the electricity system and there is limited electricity available within the Arc region to produce hydrogen by electrolysis.

The total operating costs in the Heat Networks Strategy are lower than the Green Gas Strategy. This is mainly due to the co-generation of electricity and heat with high overall efficiencies requiring less gas and electricity imports from the transmission system.

The Electric Strategy operating costs consists largely of electricity imported from the transmission network into the Arc Energy Hubs. This is due to limited low carbon distributed electricity generation capacity within the region. As electricity from the transmission systems is almost carbon-free (nuclear, offshore, and onshore wind), it is imported to meet the electricity demands for heating and EV charging.

The total operating costs are the lowest in the Unconstrained Strategy. This is to be expected as the Arc Energy Hubs can choose from several technologies to minimise the overall operating costs.

b. Investment costs

The investment costs within the Arc Energy Hubs include

1) new electricity generation and heat supply capacity,
2) network expansion by adding new natural gas, hot water and hydrogen pipes, and electrical circuits.

The investment costs of additional electricity generation and heat supply capacity, and network expansion were calculated for the year 2050. These were not calculated by the model (objective function) but done outside the model. The capital costs for technologies and networks were taken from (BEIS, 2019b, 2016; ENA, 2019; ETI, 2013). An example of investment cost calculation for the Baseline scenario is given in Appendix C.2.

Given that the analysis is focused on the Arc region only, any requirement for investment outside the Arc Energy Hubs was not included in the calculations.

c. Annualised cumulative costs (operating and investment) of implementing the Energy Supply Strategies

The annualised cumulative cost from 2015 to 2050 for the implementation of each Energy Supply Strategy was calculated (this was done also outside the model). The total annualised cost combines the investment and operating costs including an annuity rate of 7.5% that assumes a 20-year lifespan for new assets. Table 7.6 shows the annualised cumulative costs of implementing the Energy Supply Strategies for the Baseline Scenario.

Table 7.6 – Annualised cumulative costs from 2015 to 2050 for implementing the Energy Supply Strategies in the Baseline Scenario

	Annualised cumulative costs (£ Billion)			
	Electric	Heat Networks	Green Gas	Unconstrained
Operating costs	59.4	66.2	80.9	51.5
Investment costs for electricity generation and heat supply capacity	13.4	57.5	22.6	20.1
Investment costs for network expansion	14.4	45.8	15.1	35.1
Total	87.2	169.5	118.6	106.7

The annualised cumulative costs were converted to a per dwelling basis. This accounts for differences in total dwellings in the Arc Scenarios. Figure 7.15 shows the annualised costs per dwelling for the Baseline Scenario. The Heat Networks Strategy has the largest annualised costs per dwelling, approximately £2300 per annum. The Electric Strategy has the lowest annualised costs of £1200 per dwelling per annum.

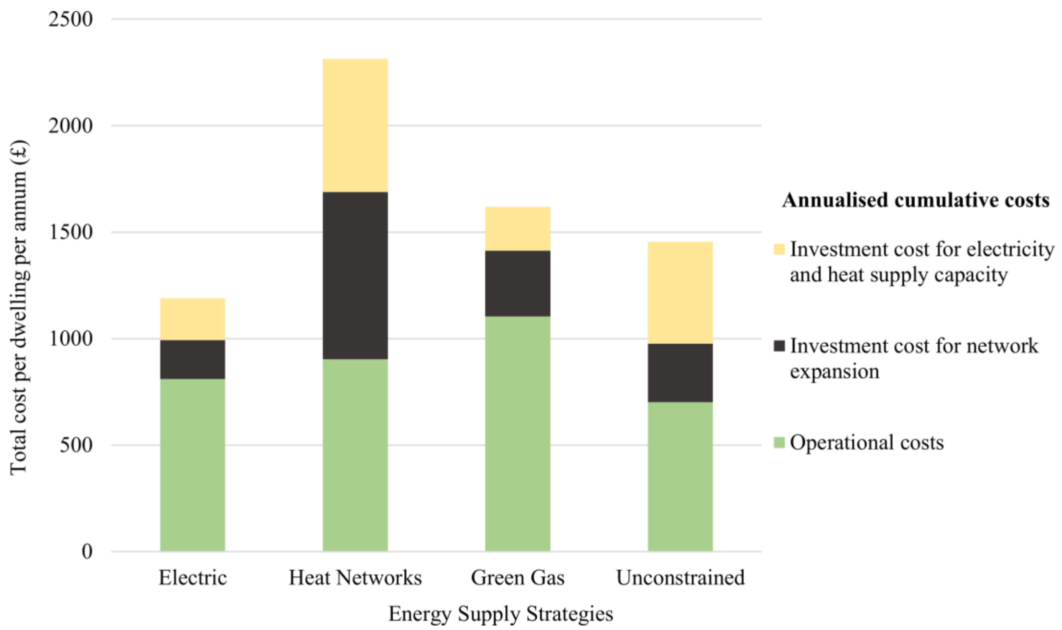

Figure 7.15 – The annualised costs per dwelling for the Baseline Scenario to implement Energy Supply Strategies in 2050.

In the Heat Networks Strategy, the annualised costs per dwelling are the largest mainly with network expansion costs for district heating networks. This is mainly due to high costs related to civil engineering works (digging trenches that are approximately three times deeper than for electricity cables and gas pipes), pipes and connections (hydraulic interface units and connections within buildings) (DECC, 2015). In addition, electricity generation and heat supply capacity costs are incurred with the installation of CHP units connected to the district heating networks.

The Green Gas Strategy shows lower annualised costs per dwelling than the Heat Networks Strategy. Heat supply capacity costs are reduced as some components of hydrogen boilers can be adapted from existing technologies (e.g. burners from natural gas boilers and flame failure detection system from industry). The repurposing of the natural gas distribution system to transport hydrogen reduces the requirement for laying new hydrogen pipelines. Therefore, overall network expansion costs are reduced.

The Unconstrained Strategy across all scenarios use heat pumps and expensive waste CHP systems such that the operating costs are minimised (as depicted by the model objective function). However, heat networks need to be deployed alongside waste CHP units incurring high overall network expansion costs. With all investment costs included, the annualised costs per dwelling are larger than the Electric Strategy.

The Electric Strategy shows the lowest electricity and heat supply capacity costs mainly due to the reductions in heat pump capital costs expected by the 2030s (BEIS, 2019b). Network expansion costs are mainly used to reinforce the electricity network. Despite the high costs of underground power cables, overall network expansion costs remain lower compared to other Energy Supply Strategies. Overall, the Electric Strategy shows the lowest annualised costs per dwelling.

7.6. Summary

Modelling of the Oxford-Cambridge Arc region generated a diverse range of Energy Supply Strategies to meet future energy demands. The Energy Supply Strategies were defined using the options for heat supply from the use of low-carbon electricity in the Electric Strategy, combined heat and power technologies in the Heat Networks Strategy and hydrogen in the Green Gas Strategy.

In the Electric Strategy, electric heating and rapid uptake of electric vehicles doubles the annual and peak electricity generation in 2050 (compared to 2015), requiring significant additional generating and electrical network capacity. Annual and peak electricity demands are considerably low in the other Energy Supply Strategies as other fuels (hydrogen, biomass and waste) are used to supply heat.

The utilisation of EV batteries supplies electricity up to 18% during the peak hour in addition to local renewables across all Strategies. The use of combined heat and power units in the Heat Networks Strategy shows distributed electricity generation meeting up to 60% of annual electricity demands. However, the national electricity transmission system would still be required to provide supply and demand balance within the Arc Region in all Strategies.

Natural gas use decreases by at least 90% in 2050 compared to 2015 in the Electric Strategy. The highest natural gas use is shown in the Heat Network Strategy for the gas CHP units, followed by Green Gas Strategy for hydrogen production using Steam Methane Reformation.

The Heat Networks and Green Gas Strategies have high upfront capital costs and operational costs for the technologies analysed, in comparison with incumbent technologies and networks such as gas distribution networks and boilers. Electrification of heating in the Arc region was shown to be the most cost-effective way to meet emission targets across all Arc Scenarios despite requiring significant additional generation and electrical network capacity. However, for existing dwellings, this will entail a radical change in infrastructure at the end-user level such as the installation of heat pumps and will be disruptive to householders.

8. Impacts of local energy supply strategies on national electricity and natural gas transmission networks

8.1. Introduction

The CGEN+Energy Hubs Model was used to investigate the impacts of local Energy Supply Strategies on operating the national electricity and natural gas transmission networks. Four local Energy Supply Strategies were defined in Chapter 7 based on options for heat supply, 1) Electric, 2) Heat Networks, 3) Green Gas and 4) Unconstrained and to meet the 80% reduction in CO_2 emissions of 1990 levels The Energy Supply Strategies were modified to replace the use of fossil fuels by low-carbon electricity and hydrogen for heating, industry, and transport to move away from the 80% reduction target and help achieve net-zero by further reducing CO_2 emissions. Each modified Energy Supply Strategy was applied simultaneously to all Energy Hubs in GB for the simulations performed using the CGEN+Energy Hubs model. The study assessed how each local Energy Supply Strategy could help to meet the net-zero CO_2 emissions target in 2050.

8.2. Modifications made to the Energy Supply Strategies

Modifications were made to the Energy Supply Strategies defined in Chapter 7 to move from the 80% reduction to net-zero in CO_2 emissions. The following modifications were made using the assumptions given by (CCC, 2019a; National Grid, 2019a) for technology uptake and energy supply capacity.

- The use of natural gas for heating was substantially reduced particularly in the Heat Networks and Green Gas Strategies where natural gas was further replaced by hydrogen, biomass, and low-carbon electricity.
- Grid-scale electric battery storage capacity was included in all strategies.
- Hydrogen production (using electrolysis and Steam Methane Reformation) and storage was allowed in all strategies.

Table 8.1. shows a summary of the modified Energy Supply Strategies.

Table 8.1 – Summary of the modified Energy Supply Strategies (2050)

Energy sectors within the Energy Hubs	**Energy Supply Strategies**			
	1). Electric	**2). Heat Networks**	**3). Green Gas**	**4). Unconstrained**
Heat	• Heat is supplied completely by electricity using heat pumps, resistive heating, and electric boilers.	• Half of the total heat is supplied by district heating networks using large heat pumps, fuel cells, biomass, and waste CHP units. • The availability of biomass and solid waste for heating is restricted within Energy Hubs. • Homes without a heat network connection use either hydrogen boilers or heat pumps.	• Heat supplies are mainly from building level hydrogen boilers. • Homes without access to hydrogen supplies use heat pumps or are connected to a district heating network (via biomass/biogas and fuel cell CHP units).	• The optimisation was free to select **any heating technology** modelled to meet demand at the **lowest operational costs** whilst adhering to physical constraints. • The availability of biomass and solid waste for heating is restricted within the Energy Hubs.
Electricity	• Distributed generation within the Energy Hubs is mainly from wind, solar photovoltaic (PV) with access to grid-scale battery storage systems. • Backup gas-fired generators are installed to compensate for the variability in wind and PV generation. • CHP units in district heating applications supply electricity as they produce heat (heat demand-driven CHP operation is assumed).			
Gas	• Transmission grid supplies are available with limited gas storage facilities. • A large capacity of electrolysers is installed to produce hydrogen. • Hydrogen is also produced via Steam Methane Reformation (SMR) with Carbon Capture and Storage (CCS). • Hydrogen production from SMR and electrolysers have access to hydrogen storage facilities (pressure bullets). • Hydrogen is supplied via new hydrogen pipelines and re-purposed gas distribution pipes.			

Alongside the changes in energy sectors in the Energy Hubs, different assumptions were used for,

- the uptake in electric and hydrogen vehicles to decarbonise road transport, adapted from (BEIS, 2019h; CCC, 2019a; DfT, 2018)
- the use of low-carbon electricity and hydrogen as industrial fuel, adapted from (BEIS, 2019g)

Table 8.2 summarises the assumptions used for road transport and industrial fuel in the modified Energy Supply Strategies. In the Electric and Unconstrained Strategies, low-carbon electricity is largely utilised. In the Heat Networks and Green Gas Strategies, both low-carbon electricity and hydrogen are used.

Table 8.2 – Summary of the assumptions used to decarbonise road transport and industrial fuel across the modified Energy Supply Strategies (2050)

Transport / Industry fuel	Energy Supply Strategies			
	Electric	Unconstrained	Heat Networks	Green Gas
Decarbonisation of road transport	• Cars and vans are all battery electric vehicles. • Most heavy goods vehicles are plug-in hybrids and the rest use hydrogen fuel cells.		• Half of all cars and vans are battery electric vehicles and the other half are hydrogen fuel cell vehicles. • Half of the heavy goods vehicles are plug-in hybrid electric vehicles and the other half use hydrogen fuel cells.	
Industrial fuel	• The majority of industrial low-temperature (e.g. for the food and paper industries) and high-temperature processes (e.g. glass and ceramics) were converted to use low-carbon electricity. • The remaining industrial processes consume natural gas.		• Most industrial low-temperature processes were converted to use low-carbon electricity. • Hydrogen is used for most industrial high-temperature processes. • The remaining industrial processes consume natural gas.	

8.3. Energy demand and supply capacity data

The energy demands (heating and non-heating including transport) for each modified Energy Supply Strategy were found using the National Energy Demand and National Transport models[5]. Figure 8.1 shows the heating and non-heating energy demands, and supply capacity data inputs to the CGEN+Energy Hubs model.

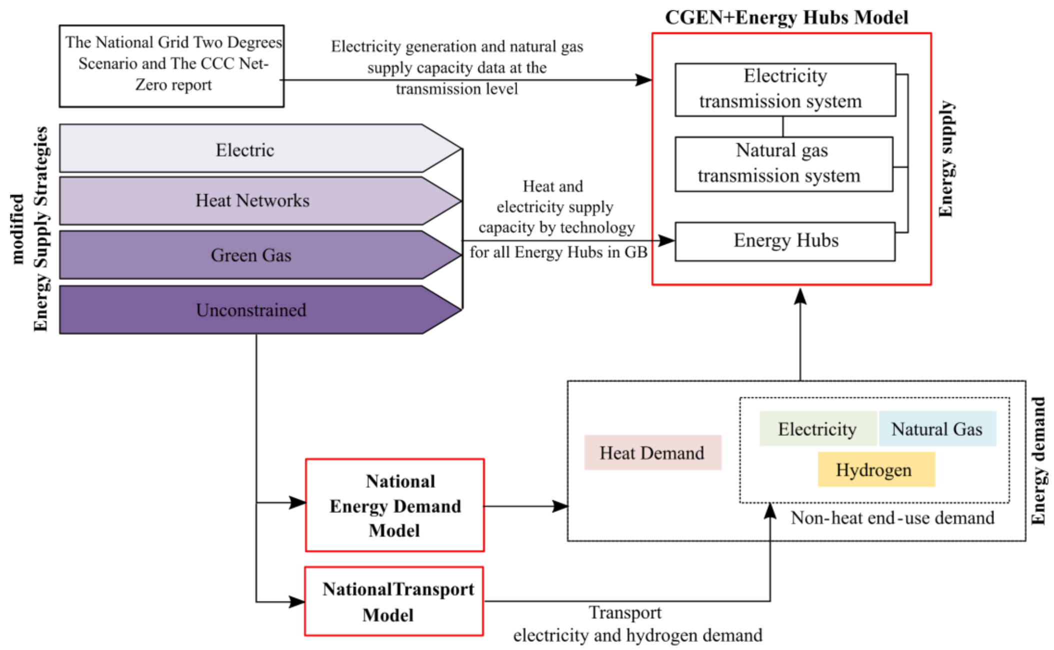

Figure 8.1 – Energy demand and supply capacity inputs to the CGEN+Energy Hubs Model

[5] Since the Energy Supply Strategies are focused on energy-transport interactions, the modifications made with the National Water Supply Model was not used.

8.3.1. The energy demand of GB

The energy demands of GB for each modified Energy Supply Strategy were found using assumptions for population, additional dwellings and gross value added (GVA) from (BEIS, 2018k) and industrial fuels given in Table 8.2. These assumptions were used as inputs to the National Energy Demand Model (Eggimann et al., 2019). The model was run to calculate heating and non-heating (excluding transport) energy demands for GB out to the year 2050.

The National Transport Model (Lovrić et al., 2017b) provided the energy demands for transport (electricity and hydrogen demands) using the assumptions for population growth from (BEIS, 2018k) and the change in vehicle engine types given in Table 8.2.

Figure 8.2 shows the calculated annual heating and non-heating energy demands for GB (including energy demand for transport).

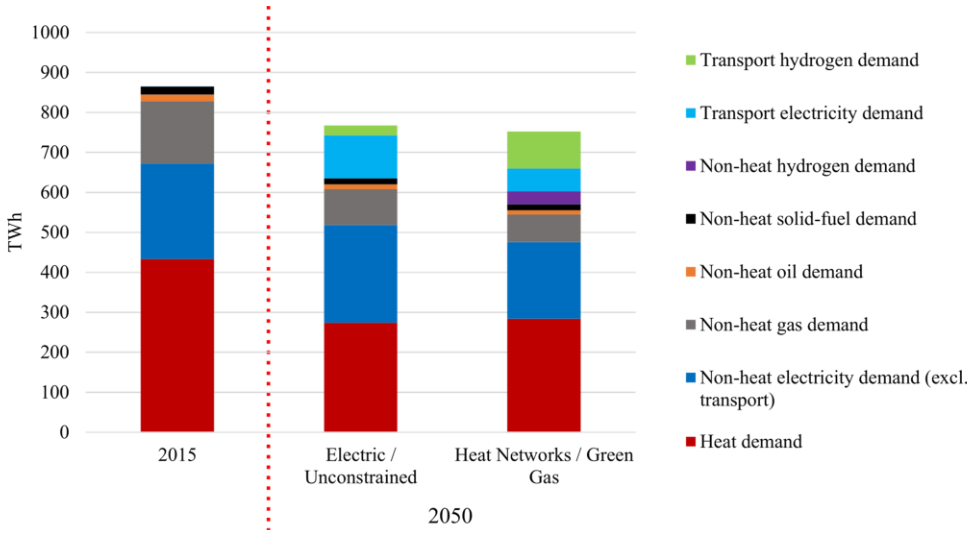

Figure 8.2 – Annual end-use energy demands in GB for heating and non-heating (including transport) in 2015 and 2050 across modified Energy Supply Strategies.

8.3.2. Energy supply capacity

The energy supply capacity needed for an 80% reduction in emissions for the GB electricity and natural gas transmission systems and the Energy Hubs were adopted from the National Grid Two Degrees Scenario (National Grid, 2019a). In addition, data and assumptions for the energy supply capacity needed for net-zero were taken (e.g. electricity generation and hydrogen production) from the CCC net-zero report (CCC, 2019a).

Electricity generation capacity in the national electricity transmission system was the same across all the modified Energy Supply Strategies. Table 8.3 shows the installed electricity generation capacity in the electricity transmission system.

Table 8.3 – Installed electricity generation capacities in the national electricity transmission system in 2015 and 2050

Generation technology	**Installed capacity – GW**	
	2015	**2050**
Oil	0.8	0.0
CCGT with Carbon Capture and Storage (CCS)	0.0	42.9
Coal	17.3	0.0
Gas (CCGT + OCGT)	26.9	1.0
Hydro	1.1	1.3
Pumped hydro	2.7	5.8
Interconnectors	3.9	20.1
Other (tidal and marine)	0.0	3.9
Nuclear	8.9	18.6
Onshore wind	4.1	17.2
Offshore wind	4.3	62.0
Solar	0.3	0.9
Battery	0	5.3
Biomass with Carbon Capture and Storage (BECCS)	0	7.0
Total	*70.5*	*185.9*

Energy supply capacity data for the Energy Hubs were calculated according to the Energy Supply Strategy selected. This ensures that the energy supply capacity meets the heating and non-heating energy demands across all modified Energy Supply Strategies. Table 8.4 shows the aggregated electricity generation capacity in all Energy Hubs.

Table 8.4 – Aggregated electricity generation capacity in all Energy Hubs across modified Energy Supply Strategies

Generation Type	**Installed capacity – GW**				
	2015	**2050**			
		Electric	**Heat Network**	**Green Gas**	**Unconstrained**
Gas (non-CHP)	1.3	1.5			
Onshore wind	3.7	22.2	11.4		22.2
PV	6.7	41.1			
Gas CHP	2.3	0.0	1.3	0.0	1.3
Oil (diesel etc.)	0.4				
Biomass CHP	0.4	0.9	3.1	3.1	3.1
Waste CHP	0.0	0.9	3.1	1.5	3.1
Fuel cells	0.0	1.2	4.6	3.1	4.6
Vehicle to grid	0.7	9.9			
Battery storage	0.0	15.9	11.9		15.9
Total (GW)	*16.3*	*94.5*	*88.8*	*84.4*	*103.6*

Table 8.5 shows the calculated heat supply capacity in all Energy Hubs.

Table 8.5 – Aggregated heat supply capacities in all Energy Hubs across modified Energy Supply Strategies

Technology	Installation	2015 (GW_{th})	Heat supply capacity (GW_{th}) in 2050			
			Electric	Heat Networks	Green Gas	Unconstrained
Air source heat pumps	Building level	0.3	25.2	9.0	3.9	25.2
Gas boilers	Building level	44.0				
Electric boilers	Building level		4.1			4.1
Resistive heaters	Building level	5.5	3.6			5.5
Hydrogen boiler	Building level			10.1	20.3	20.3
Hybrid heat pump	Building level	0.1	4.1		6.1	6.1
Oil boilers	Building level	6.5				
Gas CHP	District heating network			2.0		2.0
Biomass CHP	District heating network	0.1		4.6	4.6	4.6
Waste CHP	District heating network			4.6	2.3	4.6
Gas Boilers	District heating network					
Heat Pumps	District heating network			4.1		4.1
Hydrogen fuel cell	District heating network			7.0	4.6	7.0
Total (GW_{th})		56.5	37	41.4	41.8	83.5

8.4. Simulations performed using the CGEN+Energy Hubs model with net-zero CO_2 emissions constraint

8.4.1. Simulation

Simulations were performed using the CGEN+Energy Hubs Model for all Energy Supply Strategies in 2015 and 2050. Each simulation year consisted of four seasons and a representative week was modelled in each season using hourly time granularity. During each simulation, the CGEN+Energy Hubs Model performed an operational analysis of the entire GB energy system, with Energy Supply Strategies applied to all the Energy Hubs.

8.4.2. Net-zero CO_2 emissions

For the simulation in 2050, a constraint was applied to the entire GB energy system to ensure net zero in annual CO_2 emissions. Firstly, total CO_2 emissions were calculated from electricity generation, heat supply, hydrogen production and non-heat end-use of fossil fuels (in industry, commercial and residential sectors). Then, the net value of CO_2 emissions was calculated by accounting for negative emissions from the Bio-Energy with Carbon Capture and Storage plants (BECCS) (National Grid, 2019a) over a year.

The Bio-Energy with Carbon Capture and Storage plants were assumed to produce negative emissions of -0.861tCO_2 for every unit of electricity produced (ENA, 2019). The negative emissions factor was determined by the CO_2 absorbed during the growth of crops and plants for feedstock, upstream CO_2 emissions in feedstock processing and transportation, and the post-combustion capture of CO_2 during electricity generation (ENA, 2019; The Royal Society, 2018).

8.5. Results of simulations of the GB energy system

The results of the simulations performed using the CGEN+Energy Hubs Model are shown for the entire GB energy system across the modified Energy Supply Strategies in 2050. These are,

- electricity supplied from transmission connected and distributed generators (8.4.1)
- natural gas supply from reception terminals and storage facilities (8.4.2)
- hydrogen production (8.4.3)
- emissions from electricity generation, hydrogen production, non-heating end-use of fossil fuels (8.4.4)
- operating costs (8.4.5)

8.5.1. Electricity supply

Electricity supplied from the transmission connected generators and distributed generation in the Energy Hubs meets the GB electricity demand for heating, transport, hydrogen production, and other non-heating end-uses. Electricity is also imported from and exported to Europe via electricity interconnectors.

Figure 8.3 shows the annual electricity consumed by end-use. In 2050, annual electricity consumption doubles compared to 2015, with an average of 610TWh of all Energy Supply Strategies. In the Electric and Unconstrained Strategies, 530TWh of electricity is consumed annually for heating, transport, and industrial end-uses. In the Heat Networks and Green Gas Strategies, 300TWh of electricity is consumed to produce hydrogen using electrolysis.

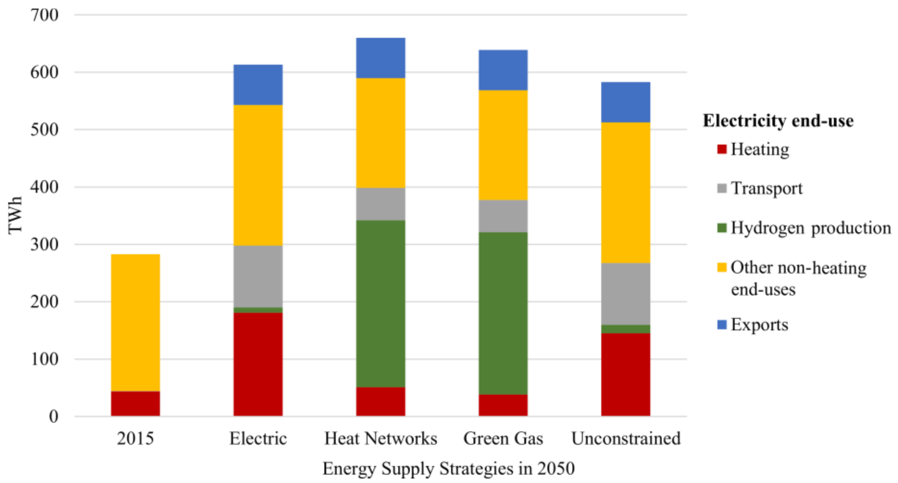

Figure 8.3 – Annual electricity used for heating, transport, hydrogen production and other non-heating end-uses (including exports) across Energy Supply Strategies in 2050

a. Annual electricity supply

Figure 8.4 shows the annual electricity supplied through the transmission system by technology and the total distributed generation (renewable and non-renewable) from all the Energy Hubs. Electricity supplied through the transmission system in 2050 is largely from wind farms and nuclear power stations alongside electricity imports. The annual distributed electricity generation increases from 22TWh in 2015 to an average of 130TWh in 2050 across all Energy Supply Strategies.

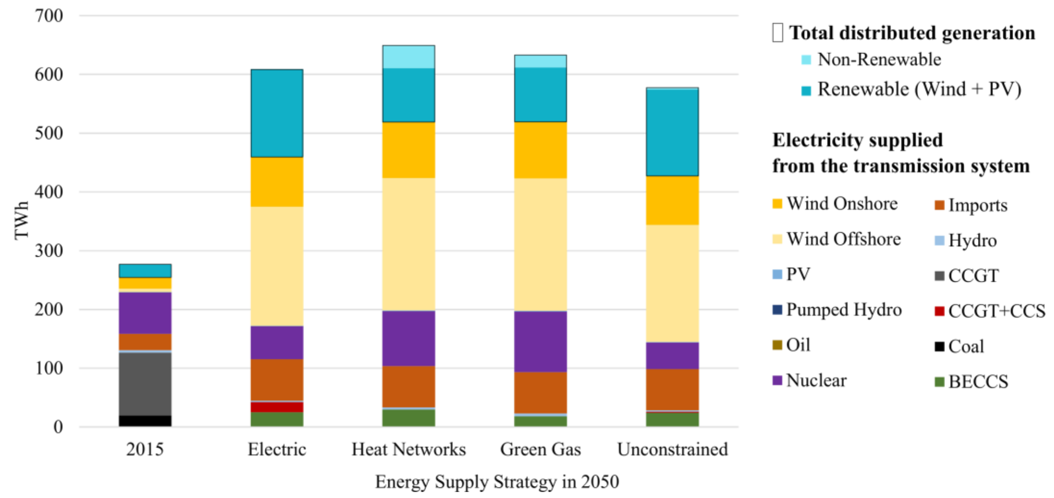

Figure 8.4 – Annual electricity supplied through the transmission system by technology, and the total distributed generation (renewable and non-renewable) in 2015 and across Energy Supply Strategies in 2050

In the Electric and Unconstraintd Strategies, 290TWh of electricity is generated from large onshore and offshore wind farms. In the Heat Networks and Green Gas Strategies, electricity generated from wind farms increases to 320TWh, as renewable electricity is used to produce hydrogen. Consequently, less curtailment and an increased electricity generation from nuclear power stations are shown compared to the Electric and Unconstrained Strategies.

The Electric Strategy shows 17TWh of annual electricity generated from CCGT plants with carbon capture and storage (CCS). These are run as a response to shortfalls in renewable electricity generation especially when there are large electricity demands from heating and transport.

Distributed electricity generation from renewables and non-renewables meets up to 33% of the annual end-use electricity demands across all Energy Supply Strategies. Renewables (onshore wind and PV systems including domestic PV) generate most of the total distributed generation. The total of distributed renewable electricity generation averages at 110TWh. Combined heat and power units are the main non-renewable sources of electricity generation used. The largest electricity generation from combined heat and power units is shown as 40TWh in the Heat Networks Strategy.

Electric batteries connected to the distribution system are used to store excess renewable electricity during low demand periods and discharge electricity during peak demand periods. In the Heat Networks and Green Gas Strategies, 4TWh of electricity is supplied through battery storage systems during peak hours. In the Electric and Unconstrained Strategies where no distributed CHP units are used, electricity supplied by discharging the batteries during peak hours has increased to ~11TWh.

Figure 8.5 shows the hourly electricity supplied from the transmission system by technology and total distributed generation (renewable and non-renewable) during a winter day in 2050. The interconnector exports are shown as negative values in the figure.

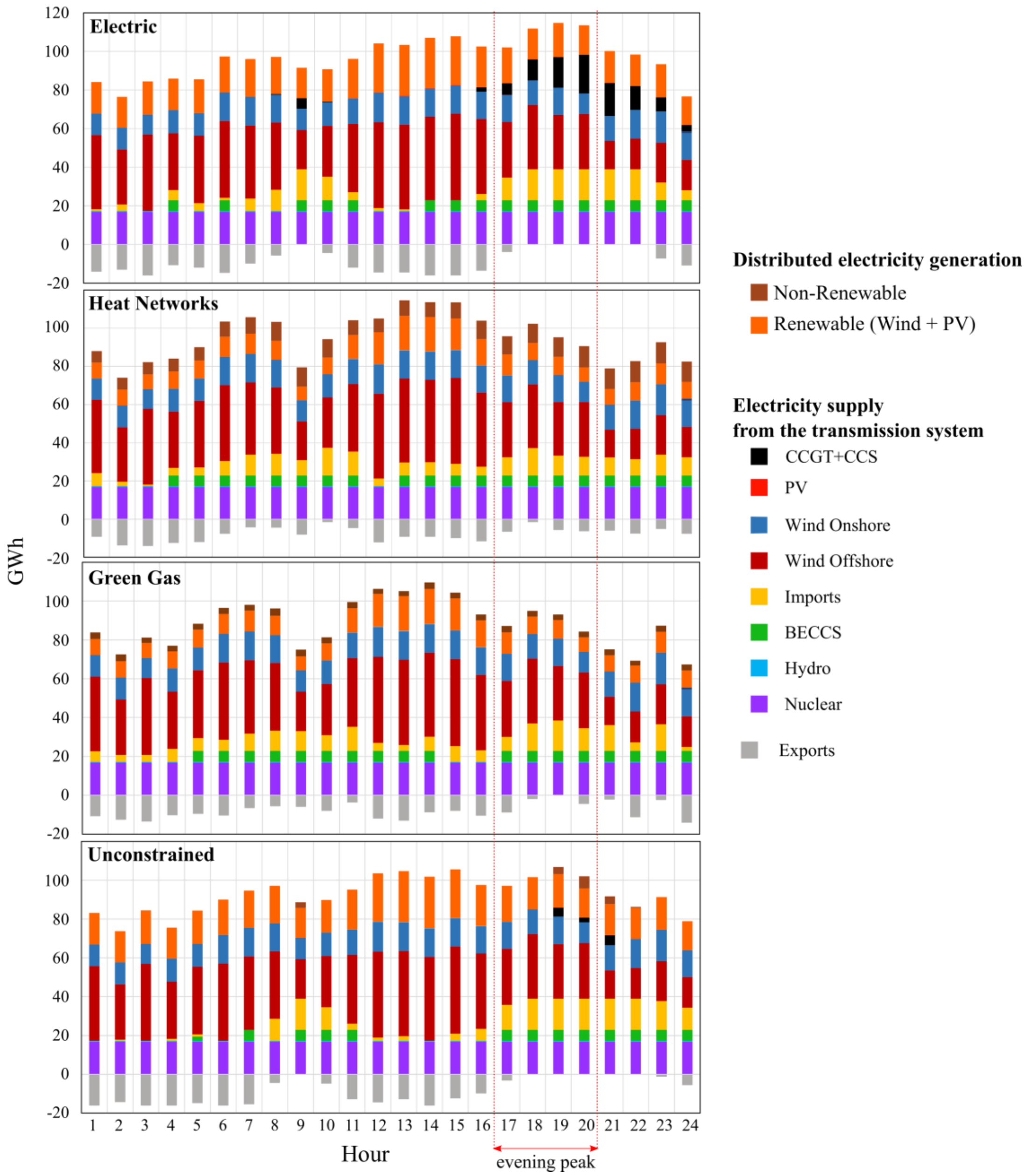

Figure 8.5 – Electricity supplied through the transmission system by technology, and total distributed generation (renewable and non-renewable) across Energy Supply Strategies in 2050

a. Electricity supply during peak hours (7 am – 9 am and 5 pm – 8 pm)

In the Electric Strategy, the electricity generation shows a peak of 120GW between 5 pm – 8 pm. This is due to the large electricity demand for heating from heat pumps and EV charging. As electricity supply is largely from wind plants (onshore and offshore), a shortfall in supply during the peak hours results in CCGT plants ramping up, and interconnectors importing to their maximum capacity.

In Heat Networks and Green Gas Strategies, electricity supply during the evening peak hours averages ~100GW as there is a low electricity demand for heating. Interconnector imports are used to meet any shortfall in the electricity supply from wind power plants. The interconnectors are used to import electricity, as it is cheaper compared to the cost of starting up and running CCGT plants with CCS.

Electricity supplied from distributed generators during the peak hours is largest in the Heat Networks Strategy. The total peak electricity supply from combined heat and power units and distributed wind plants reaches 20GW. A shortfall in wind generation is compensated by ramping up CHP units, and/or discharging electricity from grid-scale batteries. The Electric Strategy shows the largest electricity discharge of 11GW from grid-scale batteries during the peak hour.

b. Electricity generation during off-peak hours

In the Heat Networks and Green Gas Strategies, electricity generated during off-peak hours is used to produce hydrogen using electrolysis which is then stored in hydrogen storage facilities. This results in an increase in electricity generation up to 120GW during off-peak hours (mid-day 11 am – 3 pm).

In the Electric and Unconstrained Strategies, electricity generation from renewables during off-peak hours is used to charge battery storage systems and produce hydrogen in smaller quantities. Therefore, larger quantities of excess electricity are available in the transmission system (during mid-day). The majority of this is exported compared to other Energy Supply Strategies.

In all Energy Supply Strategies, interconnector flows become more variable, and bi-directional throughout the day. During off-peak periods, the interconnectors export electricity whereas during peak periods electricity is imported to balance the system.

8.5.2. Natural gas supply

Natural gas is used to meet the demand for heating, electricity generation, hydrogen production and other non-heating end-uses (largely industrial processes). Figure 8.6(a) shows the annual natural gas consumed by each end-use in 2015 and across Energy Supply Strategies in 2050. The annual natural gas supplied at reception terminals by different sources is shown in Figure 8.6(b).

The annual natural gas consumption is lower in 2050 compared to 2015 in all Energy Supply Strategies. The annual natural gas consumption is highest in the Green Gas Strategy ~210TWh where more than half is used to produce hydrogen using Steam Methane Reformation. The Unconstrained Strategy shows the lowest annual natural gas supply at 100TWh where almost all the gas is used for non-heating end-uses (cooking, industrial processes).

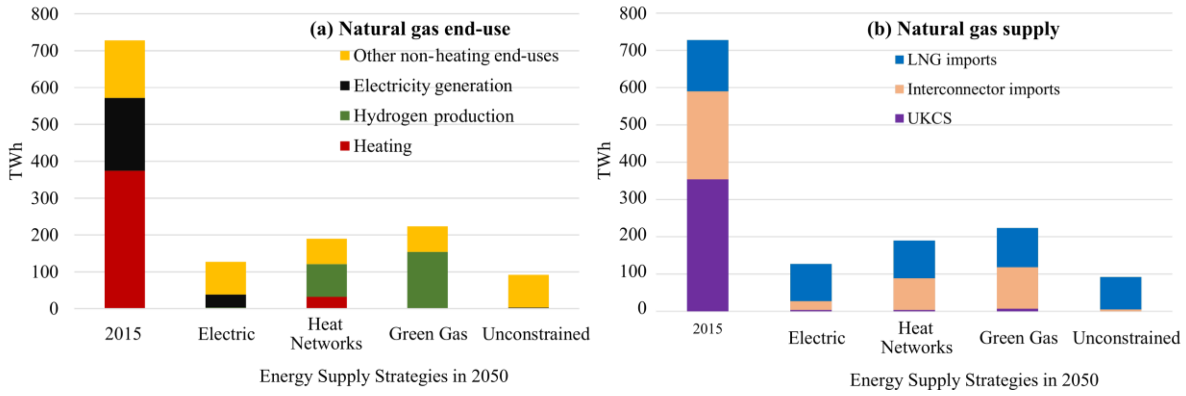

Figure 8.6 – (a) Annual natural gas consumed for heating, electricity generation. hydrogen production and other non-heating end-uses and (b) annual natural gas supply by source in 2015 and across Energy Supply Strategies in 2050

a. Annual natural gas supply

In 2050, all Energy Supply Strategies rely on imported natural gas from continental Europe and worldwide sources of liquified natural gas (LNG). This is mainly due to the decline in natural gas production in the UK Continental Shelf (UKCS). Shale gas from GB was not included in this study.

Electric and Unconstrained Strategies have low gas demands and show a dependency on LNG imports. This is mainly due to the decline in gas production in the Norwegian gas fields responding to low gas demands across the EU (National Grid, 2019a).

In Heat Networks and Green Gas Strategies, there is a higher natural gas use compared to other Strategies due to hydrogen production using Steam Methane Reformation. This increase in the GB gas demand results in an additional 110TWh of natural gas imported via interconnectors. Interconnector imports compete with LNG as natural gas demand increases (National Grid, 2020b).

b. Daily natural gas supply during a representative week in winter

The daily natural gas supply in 2050 drops significantly in all Strategies from the 5115 GWh/peak-day (465mcm/peak-day) in 2015. Figure 8.7 shows the impact of variations in renewable electricity generation on daily natural gas supply over the representative winter week in 2050. In all Strategies, a decrease in renewable generation shows an increase in the daily natural gas supply.

The Electric Strategy shows the largest increase in daily natural gas supply from 300GWh to 1400GWh. This corresponds to an increase in the use of CCGT plants that generated an additional 500GWh of electricity with the shortfall in renewable generation.

The Heat Networks and Green Gas Strategies show an increase of daily natural gas supply from 1100GWh to 1800GWh. This is due to increased production of hydrogen using natural gas by Steam Methane Reformation. Hydrogen production using electrolysis reduces with the shortfall in renewable electricity generation. However, as hydrogen is available to be withdrawn from storage facilities to meet the demands, there is no significant increase in the use of natural gas to produce hydrogen.

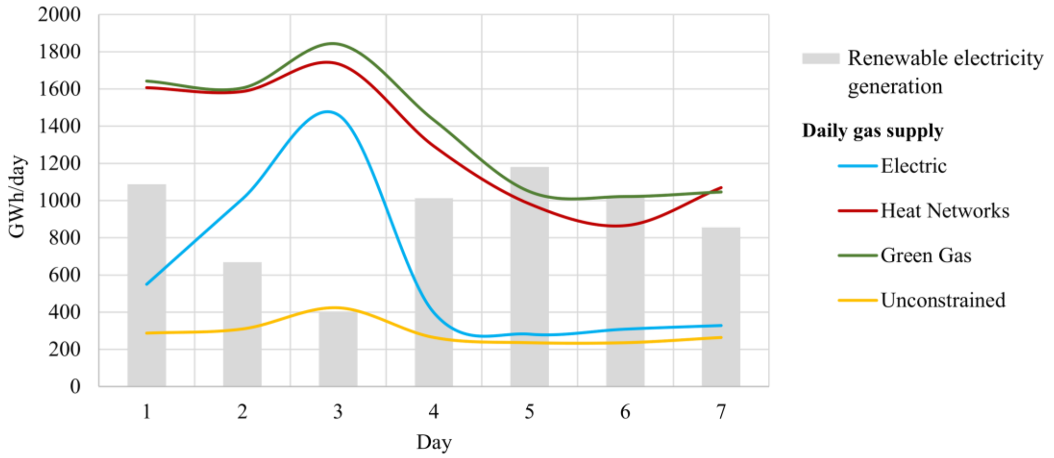

Figure 8.7 – The impact of variations in renewable electricity generation from Wind and PV on daily natural gas supply over a representative winter week across Energy Supply Strategies in 2050

8.5.3. Hydrogen production

In all strategies, hydrogen is produced by Electrolysis and Steam Methane Reformation (SMR) to meet the demands for heating, transport, and industrial fuel in 2050. Hydrogen production using electrolysis is favoured when high levels of excess electricity are available from renewables during low electricity demand periods. Hydrogen storage facilities (pressure bullets) enable the storage of hydrogen produced via electrolysis when the hydrogen demand is low and withdrawal during peak hydrogen demand periods. The remaining hydrogen demand is met by hydrogen produced using natural gas by SMR facilities with CCS.

The Electric and Unconstrained Strategies show the lowest hydrogen production (~24TWh/year) as hydrogen demand is only for refuelling hydrogen heavy goods vehicles. The total hydrogen production is from electrolysis while hydrogen storage facilities are largely used to store hydrogen and withdraw it during peak hydrogen demand periods.

The Green Gas Strategy shows the highest annual hydrogen production approximately 360TWh/year where 265TWh is used for heating in hydrogen boilers. Electrolysis accounts for 53% of total hydrogen production and the remainder is produced by SMR facilities with CCS. Total hydrogen withdrawn from storage facilities during peak demand periods is ~30TWh.

The Heat Networks Strategy shows the second-largest hydrogen production where 63% is from electrolysis. This is mainly due to increased distributed generation (CHP units running for heating), resulting in a large availability of excess renewable electricity compared to the Green Gas Strategy.

During winter, hourly hydrogen production reaches a peak of 120GW on average in the Heat Networks and Green Gas Strategies. In both strategies, hydrogen is produced from SMR during the peak electricity demand periods. This is due to electricity from renewables being used to balance the electricity system and therefore low levels of excess electricity are available to produce hydrogen from Electrolysis.

8.5.4. Emissions

Total CO_2 emissions in GB were calculated from electricity generation, heat supply, hydrogen production and non-heating end-use of fossil fuels. Annual emissions in 2050 are reduced from 175MtCO_2 in 2015 to on average 22MtCO_2 across all Energy Supply Strategies. The lowest annual CO_2 emissions are 17MtCO_2 shown in the Electric Strategy. The Heat Networks Strategy shows the highest annual emissions of 26 MtCO_2.

Across all Energy Supply Strategies, the annual CO_2 emissions are largely from the use of fossil fuels in industry. In addition to this, annual CO_2 emissions from heat supply are largest in the Heat Networks Strategy due to the use of gas-fuelled CHP units which were not replaced by low-carbon technologies. The Green Gas Strategy shows the largest emissions from hydrogen production due to the use of natural gas in Steam Methane Reformation, as only 95% of CO_2 is captured in the process.

Figure 8.8 shows the total annual CO_2 emissions and the electricity generated by Bioenergy with Carbon Capture and Storage (BECCS) plants across all Energy Supply Strategies.

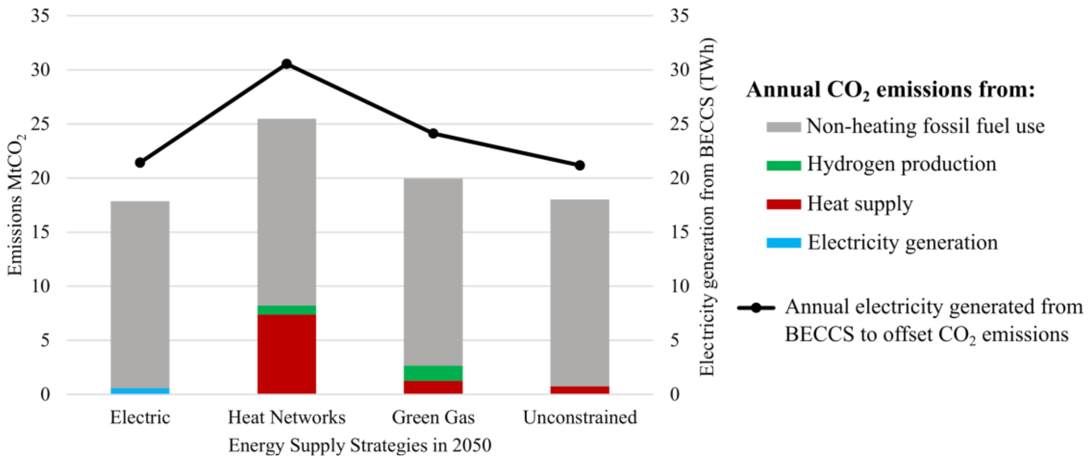

Figure 8.8 – Annual CO_2 emissions and electricity generated from BECCS to offset CO_2 emissions across Energy Supply Strategies in 2050

The annual CO_2 emissions were offset by the negative emissions accounted for by the electricity generated from Bioenergy with Carbon Capture and Storage (BECCS) plants. This ensures that the net value of annual CO_2 emissions was zero in all Energy Supply Strategies.

The Heat Networks Strategy shows the highest annual electricity generation of 30TWh from BECCS using 100TWh of plant biomass (approximately 17Mt of dry wood pellets). This results in an additional increase in biomass imports into GB for electricity generation compared to 2015 (7Mt of dry wood pellets).

8.5.5. Operating costs

The total operating costs include the costs of gas supply and electricity generation at the transmission level, variable operating costs of distributed technologies in the Energy Hubs, and carbon costs for the total CO_2 emissions over a year. The total operating costs were calculated by the objective function of the CGEN+Energy Hubs model. For this calculation, a fuel price projection for the year 2050 was used based on (BEIS, 2018k) as inputs to the CGEN+Energy Hubs model.

Figure 8.9 shows the total operating costs across Energy Supply Strategies in 2050. The total operating costs are highest in the Heat Networks Strategy and lowest in the Unconstrained Strategy.

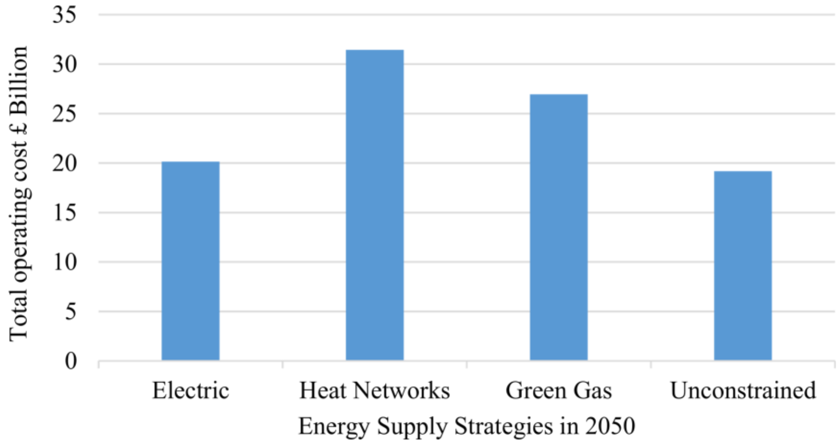

Figure 8.9 – Total operating costs given by the objective function of the CGEN+Energy Hubs model across Energy Supply Strategies in 2050

The Heat Networks Strategy shows the highest operating costs mainly due to high carbon costs, and high operating costs of BECCS plants (including the cost of imported biomass). These high costs undo some of the cost savings from co-generating heat and electricity in the Energy Hubs.

The Green Gas Strategy shows operating costs that are higher than Electric and Unconstrained Strategies. This is due to the large-scale production of hydrogen using electrolysis and SMR remains operationally expensive. In addition, operating SMR adds natural gas fuel costs which include the costs of importing natural gas to GB.

The Unconstrained Strategy shows the lowest operating costs. This is to be expected as the Energy Hubs can choose from several technologies to supply heat such that the total operating costs are minimised.

The Electric Strategy shows higher operating costs than the Unconstrained Strategy. The additional operating costs are largely from the use of expensive gas-fired plants during peak hours to compensate for the variability in renewable generation and associated costs of natural gas supply.

8.6. Summary

The CGEN+Energy Hubs Model was used to investigate the impacts of modified Energy Supply Strategies on the national gas and electricity transmission networks. The Energy Supply Strategies defined in Chapter 7 were modified to move from 80% reduction to net-zero in CO_2 emissions. The modifications replace fossil fuel use in heating, industry and transport with low-carbon electricity and hydrogen. The analysis provided an operational perspective of the GB energy system where the net-zero CO_2 emissions target is met in 2050.

The Electric Strategy showed lower operating costs compared with the Green Gas and Heat Networks Strategies to meet the emissions target. The impacts on the electricity transmission system are mainly due to the variability of renewable generation during peak electricity demand periods. Therefore, the electricity transmission system requires CCGT plants to mitigate the variability of renewable generation. Distributed battery storage systems enable the storage of excess renewable electricity during off-peak periods and withdrawal during peak electricity demand periods.

The natural gas supply is lowest in the Electric Strategy during periods when no CCGT plants are used due to plentiful renewable generation. However, the additional gas supply is required when there is a large decrease in renewable generation requiring CCGT plants to run at higher capacity factors.

The Green Gas and Heat Networks Strategies, whilst they have higher operational costs to meet the net-zero objectives highlighted different advantages. The Green Gas Strategy showed greater use of the available renewable electricity minimising the curtailments. The Heat Networks Strategy by its very design showed the use of several energy sources (biomass, waste, and hydrogen) in combined heat and power technologies to meet the net-zero target.

9. Conclusions and future work

9.1. Conclusions

The GB energy system is in a rapid transition towards achieving the target of net-zero CO_2 emissions by 2050. There is an increase in the use of renewable resources (wind and solar irradiance), bioenergy and hydrogen to decarbonise electricity generation, heating, industry, and road transport. Consequently, the interdependencies between electricity, natural gas, heating, and hydrogen supply systems are changing. For example, the direct use of natural gas for heating will be replaced by low-carbon electricity and hydrogen.

These interdependencies are likely to be much more complex at the local distribution level. There will be dispersed local integrated energy systems where different distributed: generation technologies, energy supply resources and storage systems are utilised. The operation of such local integrated energy systems will, in turn, impact the operation of national gas and electricity transmission networks.

Existing models of energy systems are not able to analyse the interdependencies between national and dispersed local energy systems. This key limitation was addressed by the modelling methods used to develop the CGEN+Energy Hubs Model.

The CGEN+Energy Hubs model was first applied to the Oxford-Cambridge Arc region and used to demonstrate the capability of analysing interdependencies between local energy systems and the backbone national gas and electricity transmission systems. This local study was then extended to the whole of GB to investigate the impact of dispersed local energy systems on the national gas and electricity networks.

9.1.1. The CGEN+Energy Hubs Model

The CGEN+Energy Hubs Model includes a detailed representation of the GB electricity and natural gas transmission networks and connected assets (i.e. large power stations and gas terminals). The representation of local energy systems as Energy Hubs was developed to model integrated local electricity, natural gas, heat, and hydrogen supply systems in geographic areas of GB. The CGEN+Energy Hubs Model performs operational analysis of integrated national and local energy systems.

The CGEN+Energy Hubs model minimises the total operating cost of electricity generation and gas supply from the transmission networks, the variable operating costs of the distributed technologies, and the penalty costs for CO_2 emissions. The constraints arise from the operational characteristics of the two transmission networks and the Energy Hub local energy systems.

The CGEN+Energy Hubs model represents the variability of renewables (wind and solar PV generation) and the availability of energy supply resources (bioenergy and waste) across all Energy Hub regions. Hourly timesteps were used to analyse the operation of renewables and storage systems. In addition, the operation of seasonal and intra-day energy storage facilities was modelled.

The CGEN+Energy Hubs model takes into account the bi-directional flows in electricity interconnectors and the characterisation of different natural gas supply resources (LNG, Shale Gas, Imports and UKCS) in the gas transmission system. For the Energy Hubs, distributed injection of hydrogen and biogas, demand response, and vehicle to grid electricity supply were modelled.

Meeting the net-zero emissions target requires policies that are coherent across different sectors, especially energy, transport, and water supply. Currently, these different sectors are analysed independently, and most whole energy system models have limited soft linking with other sector models to provide integrated analysis. To bridge this gap, the CGEN+Energy Hubs Model was integrated into a National Infrastructure Systems Model (NISMOD). Within NISMOD, the CGEN+Energy Hubs Model was coupled with,

- the National Energy Demand Model to acquire end-use energy demands across residential, commercial, and industrial consumers.
- the National Transport Model to obtain electricity and hydrogen demands for transport, and EV battery capacity to model vehicle-to-grid electricity supply.
- the National Water Supply Model provides the cooling water requirement for electricity generation.

The spatial and temporal details in whole energy system analysis and the consideration of interdependencies across national and local energy systems, and across other sectors (e.g. transport) has been identified as a requirement when providing cross-sectoral policies to meet the net-zero emissions target (BEIS, 2020; CCC, 2019b; National Grid, 2020a). These reports highlight the need for a detailed approach in renewable energy modelling, bi-directional electricity interconnector flows, characterisation of natural gas resources, demand shifting, vehicle to grid and distributed gas injection. The CGEN+Energy Hubs model provides modelling capability which allows characterisation of the whole energy system with functions that are currently not found in any single modelling tool. The CGEN+Energy Hubs model is flexible such that it allows the user to select and modify the functions required, soft linking with other sector models (transport), and spatial and temporal granularity of the analysis in a single simulation process. Therefore, a user has more control over model complexity and therefore the simulation time for model computation.

9.1.2. The impact of different Energy Supply Strategies on integrated local energy systems of the Oxford-Cambridge Arc region

The CGEN+Energy Hubs model was used to model the Oxford-Cambridge arc region and generated a diverse range of Energy Supply Strategies to meet future energy demands and contribute to the national emissions target. The choice of heat supply technology within these strategies influences the energy supply mix and therefore ways of meeting the demand for heating within the region. The performance of these energy supply strategies was analysed across different development Arc Scenarios (ITRC, 2020) using the holistic modelling approach encapsulated by the CGEN+Energy Hubs Model in which local energy supply systems were considered alongside the backbone national gas and electricity transmission systems.

Four contrasting Energy Supply Strategies were defined to investigate a diverse range of options to decarbonise heat supply in the Arc region and support the national target of reducing 80% CO_2 emissions from 1990 levels by 2050. The strategies chosen were:

1) Electric Strategy: Heating is electrified using low-carbon electricity.
2) Heat Networks Strategy: Biomass and waste fuelled combined heat and power units are used in district heating networks.
3) Green Gas Strategy: Hydrogen and biogas are used for heating, and
4) Unconstrained Strategy: A specific heat supply method is not defined in this strategy, but the CGEN+Energy Hubs Model chooses a combination of heating technologies to minimise operating costs.

Table 9.1 shows a summary of the performance of key metrics within the Arc region for each Energy Supply Strategy. The metrics are, a) energy supplied into the Arc region, b) CO_2 emissions from electricity generation, heat supply, hydrogen production, and non-heating end-use of fossil fuels, c) costs per dwelling that includes operating costs and in addition investment costs for new electricity and heat supply capacity, and network expansion by adding new natural gas, hot water and hydrogen pipes and electrical circuits.

Table 9.1 – Annual performance of key metrics within the Arc region for each Energy Supply Strategy (In each column, the minimum value is shown as green, and the maximum value is shown as red. A linear scale is then used to choose the colour gradient for the other values in the same column)

Energy Supply Strategy	a) Energy supplied into the Arc region, TWh	b) CO_2 Emissions, $MtCO_2$	c) Costs, £ per dwelling (operational and investment)
Electric	46	2	1200
Heat Networks	72	5	2400
Green Gas	65	4	1600
Unconstrained	45	2	1400

The analysis of each Energy Supply Strategy highlighted key issues related to the electrification of heat, decarbonisation of the gas network and use of heat networks.

i). Electrification of heat

Decarbonisation of heat could be achieved by switching from a system with predominately gas boilers to a system built to accommodate heat pumps (dwelling level units and larger-scale units connected to a heat network), resistive heating and storage, and running these on low-carbon electricity. The outputs of the Electric Strategy across all Arc Scenarios showed that this would require significant additional electricity generation and network capacity.

The electrification of heat (Electric and Unconstrained Strategies) in the Arc demonstrated the largest regional contribution to meet the national emissions target. Given the cost per dwelling to implement the strategy alongside near-zero-emissions in the residential and commercial sectors, the Electric strategy performed strongest across the key metrics.

The implementation of an Electric energy strategy would experience many practical challenges. For instance, in scenarios where retrofitting of existing buildings is required this would entail the requirement of radical change in infrastructure at the end-user level, such as each dwelling either acquiring a heat pump, resistive heating system or electric boiler. It becomes a great deal easier to incorporate this change on new dwellings proposed in the Arc Scenarios, especially in New Settlements and Expansion.

The public's knowledge of technologies such as heat pumps is still limited. Awareness could be increased by government and industry via promotional exemplars. Confidence could be further enhanced by ensuring that installers abide by high standards during the design and installation process.

ii). Decarbonisation of the gas distribution systems

Partial decarbonisation of the gas network can occur by mixing natural gas with hydrogen (20% by volume) and biomethane. This has the advantage that the changes for the end-use appliances such as gas cookers and boilers can be kept to a minimum. Also, programmes like the Iron Main Replacement Programme (HSE and Ofgem, 2011) is underway replacing iron pipelines with polyethylene pipes that are suitable to transport 100% hydrogen. Therefore, the prospect of near-zero carbon emissions from using hydrogen alongside relatively low network conversion costs becomes a possibility. The challenge of producing hydrogen at scale and to do so commercially and carbon-free is modelled within the Green Gas Strategy for the Arc Scenarios.

The Green Gas Strategy outputs showed hydrogen production using SMR with CCS, which is expected to be technically viable in the 2030s to sustain the hydrogen supplies to be used in heating and non-heating end-uses. The use of electrolysis within the region is limited due to the low capacity of renewable generation, hence, less "free" electricity is available to cost-effectively produce hydrogen. Large scale hydrogen production using SMR adds a substantial amount of operational costs annually. Therefore, the overall annualised costs per dwellings are the second-largest (~£1600) for the Baseline Scenario when compared with the other strategies. Annual emissions in 2050 are over 65% lower than in 2015 across all Arc Scenarios.

iii). Heat networks

The Heat Networks Strategy for the Arc Scenarios focussed primarily on CHP based heating technologies although a heat network is technology and fuel source neutral. Within the Arc Scenarios and especially with New Settlements and Expansion, given higher demand (for heat) densities and the possibility of synergies during the construction of heat networks and new dwellings, potential reductions in annual costs per dwelling are feasible. The implementation of this strategy has overall costs that are the highest across all scenarios whilst emission reductions are not as large as other strategies (~55% reduction from 2015 levels). Alternatively, if heat networks were attached to an equal capacity split between large heat pumps and CHPs, this would reduce heat technology capacity costs by over 25%. Although the addition of heat pumps would require strengthening of the electricity system which would undo some of the costs savings.

The implementation of a Heat Networks strategy was shown to be feasible but there are several areas where progress needs to be made to fully realise the advantages offered by a heat source agnostic energy vector. These include:

- **Economics:** The Heat Networks strategy was shown to have the highest overall total costs including on a per dwelling basis. This is mainly concentrated around the high capital costs for CHP plants, digging and laying of hot water pipes and connections to dwellings. Cost reductions would have to take place across all these areas for a heat network-based solution to become competitive with alternative solutions.
- **Lack of standardisation**: There is no national organisation (such as National Grid) to drive standardisation across the industry. There are several companies (which can be good for innovation) driving distinct operations regionally and locally. But currently, there is no universal approach to design layout or treatment of risks. This can lead to poor quality installations.
- **Perceived technological shortcoming:** Whilst well established abroad (especially within Europe), heat networks are still relatively new to the average UK consumer. Reports of poor service by energy services companies or others results in disproportionate bad publicity like the one published by the CMA in 2018, "there were instances of poor service quality and cases where customers were paying 'considerably more' than for non-network heat" (CMA, 2018). Furthermore, there is a distinct lack of knowledge about heat networks (heating capabilities) including the charging methodology and awareness of the services offered.

- **Complexity:** This can range from ownership issues such as who owns the network, who operates and regulates it, to what the grievance procedures are. In contrast to heat networks, natural gas networks are regulated, and most people are comfortable in the knowledge that they are protected by a regulator.

Overall, the analysis suggests the Electric Strategy would be able to meet the CO_2 emissions target in 2050 at the lowest annualised costs (investment and operation) per dwelling within the Oxford-Cambridge Arc region. This will require investment to increase the capacity of transmission electricity supply, distributed generation, and electricity distribution networks. It was also shown that the investment for distributed generation could be reduced if EV batteries were utilised to supply electricity during peak hours.

9.1.3. The impact of local Energy Supply Strategies on the operation of national gas and electricity transmission networks

The CGEN+Energy Hubs model was used to investigate the impacts of local Energy Supply Strategies applied across all GB Energy Hubs on the operation of gas and electricity transmission networks.

The Energy Supply Strategies were modified to further reduce the use of fossil fuels for industrial processes, heating, and transport with low-carbon electricity and hydrogen to ensure that the net-zero CO_2 emissions target is met in 2050. The modified Energy Supply Strategies were applied across all Energy Hubs in GB. For each strategy, the CGEN+Energy Hubs Model showed energy supply and annual CO_2 emissions for the whole of GB. The study assessed the impacts on electricity generation and natural gas supplies from the transmission networks.

Table 9.2 shows a summary of the performance of the key metrics of the GB energy system for each Energy Supply Strategy. The metrics are, a) electricity supplied through the transmission system and distributed generation, b) renewable electricity curtailed, c) natural gas supply at reception terminals, d) CO_2 emissions from electricity generation, heat supply, hydrogen production, and non-heating end-use of fossil fuels, and e) operational costs of the GB energy system.

Table 9.2 – Annual performance of key metrics of the GB energy system for each Energy Supply Strategy (In each column, the minimum value is shown as green and the maximum value is shown as red. A linear scale is then used to choose the colour gradient for the other values in the same column)

Energy Supply Strategy	a) Electricity supply, TWh	b) Renewable electricity curtailed, TWh	c) Natural gas supply, TWh	d) CO_2 Emissions, $MtCO_2$	e) Operational Cost, B£
Electric	600	34	125	17	20
Heat Networks	650	1.5	190	26	30
Green Gas	625	1	181	21	26
Unconstrained	590	40	100	19	19

The analysis of the whole energy system with selected local Energy Supply Strategies showed the impacts on the national gas and electricity networks and highlighted key mitigating measures to ensure a secure, and cost-effective and net-zero energy supply.

i.) Impacts on the national electricity transmission system.

The national electricity transmission system is expected to maintain a prominent role in balancing electricity generation and demand. In a net-zero future, electricity supply from the transmission system is mostly from large offshore and onshore wind farms and nuclear plants. This requires the renewable capacity to grow dramatically from ~16 GW in 2015 to greater than 150GW in 2050 and Nuclear reaching a maximum of 16GW capacity where total generation capacity would need to be approximately 280GW. The generation contribution from renewables is projected to be over 400TWh (including distributed renewables) and the total generation reaching just over 600TWh in all Energy Supply Strategies by 2050.

The peak electricity demand has shown to be directly influenced by the heat and transport decarbonisation pathway. When both heating and transport is electrified (Electric and Unconstrained Strategies), it increases the national peak electricity demand to more than double the reference year peak demand (~55GW in 2015) with an unmanaged electric vehicle charging behaviour. Replacing electricity with alternatives such as hydrogen, biomass, and waste in the Heat Networks and Green Gas Strategies was able to bring down the peak electricity demand around 10-15%.

The analysis showed the key challenge in operating a predominantly low-carbon electricity system, is the intermittency of renewables, especially during peak hours. Interconnectors, flexible CCGT+CCS plants, and grid-scale battery storage systems were shown to play a key role in balancing the supply and demand subjected to variable outputs from the renewable. The higher the system peak demand, as shown in the Electric Strategy, the larger the capacity required from such flexible technologies.

In an integrated energy system, the access to storage facilities of a different form of energy illustrated maximised utilisation of renewable electricity and reduction of curtailments. The Green Gas Strategy showed greater use of distributed hydrogen storage facilities (pressure bullets) to enable the storage of hydrogen produced by renewable electricity via electrolysis during off-peak hours.

ii.) Impacts on the national natural gas transmission system.

The annual natural gas supply reduces significantly in all Strategies by 2050. Electrification leads to the largest decrease in gas supplies of over 90% and production of hydrogen at scale using SMR leads to the lowest fall over 60% compared to 2015. Given the depletion of domestic gas resources, almost all gas supplies will need to be imported (via interconnectors and as LNG).

Maintaining a cost-effective gas supply was shown to be challenging in an all-electric future considering the variability of renewables. The analysis of the Electric Strategy showed that a shortfall in renewables during electricity peak demand hours could potentially increase the daily gas supply by more than two times due to generation from CCGT+CCS plants compared to a day with plentiful renewable generation. Adequate gas volume in the system needs to be maintained as linepack and within short-term gas storage facilities.

iii.) Impacts on the cost of operating a net-zero GB energy system.

Electricity generation from BECCS plants accounts for negative CO_2 emissions and therefore ensures net-zero emissions are met nationally. Prolonged use of fossil fuels in the industry, heating and hydrogen production would require BECCS plants to run with higher capacity factors. Consequently, additional costs are incurred on biomass imports as the UK is limited with inland biomass resources. This will be in addition to the higher prices of fossil fuels subjected to a carbon tax.

The high costs of hydrogen production remain a bottleneck for realising the operational cost benefits of a net-zero GB energy system where hydrogen technologies are deployed at scale across industry, heating, and transport. Also, relying on large natural gas imports to produce hydrogen to meet the demand will incur additional costs to the system operator.

The analysis showed that there is a direct impact on the total costs of operating the GB energy system using flexible gas-fired generation technologies which compensate for the variability in renewable supply at peak demand hours. Costs will be incurred from starting up/shutting down of the plants as they are used only a few times during a year depending on the weather. In addition, there will be costs for maintaining gas supply as linepack and in short-term gas storage facilities in the gas transmission system.

Overall, the analysis provided an operational perspective of the GB energy system in implementing different Energy Supply Strategies to meet the net-zero CO_2 emissions target. The study showed that the Electric Strategy would be able to deliver the net-zero CO_2 emissions target in GB at the lowest annual operating cost. Furthermore, impacts on the operation of GB electricity and natural gas transmission networks in the Electric Strategy due to the variability of renewables were identified. Additional grid-scale battery storage capacity is suggested to mitigate these impacts and further reduce the use of CCGT+CCS generators.

9.1.4. Comparison of the Arc and GB analysis

The Arc analysis generated several Energy Supply Strategies that showed ways in which the local energy systems can meet demands while adhering to the national emission targets. The analysis was focused only on the Arc region, and the impacts on energy supply, emissions and costs of operating integrated local electricity, natural gas, heating, and hydrogen supply systems. The study was extended with a cost analysis which includes investment costs in addition to the operating costs calculated by the CGEN+Energy Hubs Model. This allowed contrasting of costs across the implementation of different

Energy Supply Strategies within the Arc region. The analysis favoured electrification of heating and transport to meet the national emissions targets at the lowest costs per dwelling.

The GB case study in contrast assumes that the Energy Supply Strategies are adopted across all GB local areas and focuses on the impacts of operating the gas and electricity transmission networks. This study did not include investment cost calculations and focused only on the operation of the GB energy system where the net-zero target is met. This study also showed that electrification of heating and transport meets the net-zero target with the lowest annual operating costs.

The studies showcased the applicability of the new CGEN+Energy Hubs model for both local and national scale studies.

9.2. Contributions of the thesis

The following contributions were made during this research.

- The CGEN+Energy Hubs model was developed by improving the established CGEN model, by integrating dispersed local energy system representations that also includes functions for demand-side response, distributed injection of hydrogen and biogas, and vehicle to grid electricity supply.
- Additional functions were implemented into the established CGEN model, 1) to improve modelling of variable renewable generation that include weather parameters (wind speed and solar irradiance) derived from climate change projections and takes into account the spatial variability, 2) to model bi-directional flows in electricity interconnectors, 3) to characterise different natural gas supply resources such as LNG, pipeline imports, shale gas and UKCS.
- The impacts of local energy supply systems on the operation of the GB energy system were demonstrated using the new CGEN+Energy Hubs model.
- The CGEN+Energy Hubs model was used to assess contrasting options to decarbonise heat and affordably reduce CO_2 emissions from the Oxford-Cambridge Arc's energy system.
- Interdependencies between energy - transport and energy - water supply systems were modelled by the integration of National Transport and National Water Supply Models with the CGEN+Energy Hubs Model.

9.3. Future Work

The CGEN+Energy Hubs model includes several assumptions and limitations where several areas were identified for future development. Firstly, the model assumes a linear relationship between wind speed and turbine power output when wind speed is between cut-in and rated wind speeds. The linear relationship results in significant errors as identified in the error analysis and would benefit from a more accurate approximation. Secondly, the Energy Hubs are limited to the shifting of non-heating electricity demands as thermal energy storage systems are not modelled. This limitation needs to be addressed as more flexibility is envisaged from the demand side in the analysis of future low-carbon energy systems. Thirdly, the battery storage modelling in the Energy Hubs requires a correction of the minimum battery storage capacity assumption. This is assumed to be zero, which is incorrect. Fourthly, the CGEN+Energy Hubs model does not model losses. This needs to be implemented in both transmission and within Energy Hubs. Finally, key input data to the model on energy demand, fuel costs, emission factors, and availability of biomass and waste require refinement against the projections from BEIS, National Grid and the CCC.

Future work using the CGEN+Energy Hubs model could investigate a different set of scenarios other than the ones investigated. The current scenarios lack the improvements to several technologies within the current heat decarbonisation debate such as hybrid heat pumps, waste heat powered district heating, and biofuel boilers. Also, hydrogen CCGTs are largely discussed in the recent National Grid Future Energy Scenarios replacing conventional natural gas CCGTs with CCS as peaking plants. The CGEN+Energy Hubs model needs refinement to use these different technologies across numerous new scenarios.

The CGEN+Energy Hubs model uses electricity generation, heat supply and hydrogen supply capacity as inputs. These capacity data need to be calculated for different Energy Hubs. The existing methodology adopts nationally aggregated capacity data from the National Grid Future Energy Scenarios and distributes across the Energy Hubs in proportion to the electricity, heat and hydrogen demands. This method could be improved by considering additional constraints from network capacity, technology build rates and investment costs. Therefore, an optimal planning module is suggested to provide more accurate input energy supply capacity data to the CGEN+Energy Hubs model for future scenario studies.

Currently, aggregated local energy supply capacity data for different geographic regions across GB are manually disaggregated. This existing process for Energy Hub design is time-consuming. A central database could be used to store all energy supply capacity data to their available spatial granularity. Then the process of disaggregating capacity data to the given spatial granularity of a defined Energy Hub could be automated through Arc GIS. This brings considerable benefits to the user in the process of designing Energy Hubs to suit their study using the CGEN+Energy Hubs model.

Modelling of the dynamic behaviour (using finer time granularity than an hour) of integrated electricity, gas, heating, and hydrogen systems results in greater accuracy and detailed analysis of interdependencies between these different systems. In addition, dynamic studies help the design of control systems for the real-time operation of complex integrated systems. However, the computational cost of dynamic modelling of an integrated energy system is of concern, especially when modelling the whole energy systems (national and local) and therefore linearisation and reduction techniques are required.

Appendix A: Electricity generation and heat supply capacity data collected for Energy Hubs

A.1. Electricity generation capacity

The calculated electricity generation capacity in each Energy Hub is given in Table A.1. The capacity data was calculated for 2015.

Table A.1 – Electricity generation capacity calculated in each Energy Hub in 2015

Energy Hub	Installed electricity generation capacity (MW)					
	Oil	Gas (non-CHP)	Wind Onshore	PV	CHP gas	CHP biomass
1	362.1	0.0	495.1	0.0	0.0	7.3
2	0.0	43.1	194.4	0.0	73.7	0.7
3	0.0	0.0	119.0	0.0	0.0	0.0
4	0.0	0.0	50.3	0.0	0.0	45.4
4	25.3	0.0	375.4	0.0	0.0	22.4
6	0.0	0.0	671.1	0.0	0.0	27.5
7	0.0	0.0	44.1	0.0	0.0	0.0
8	0.0	0.0	260.7	0.0	0.0	0.0
9	0.0	6.6	57.8	34.4	11.2	26.8
10	0.0	4.5	159.0	0.0	7.7	30.2
11	0.0	33.3	87.1	0.0	57.0	5.6
12	0.0	69.2	35.6	78.2	118.3	0.0
13	0.0	101.8	0.0	41.3	174.2	22.7
14	0.0	1.8	27.0	42.0	3.1	16.4
15	0.0	47.8	297.2	10.1	81.7	48.1
16	0.0	247.0	80.9	308.3	422.5	20.8
17	0.0	64.7	29.3	251.5	110.6	1.1
18	0.0	141.8	225.6	699.8	357.3	28.8
19	0.0	70.8	90.2	106.2	121.1	0.0
20	25.3	15.3	38.4	648.9	26.2	33.2
21	0.0	26.1	70.6	532.0	44.6	21.9
22	0.0	41.5	59.0	571.2	71.1	8.7
23	0.0	48.3	15.3	738.0	76.9	8.3

24	0.0	58.9	0.9	296.3	100.8	19.1
25	0.0	20.5	78.0	4.5	41.3	17.4
26	0.0	139.8	44.6	91.3	239.1	0.0
27	25.3	0.0	26.4	233.0	0.0	0.0
28	0.0	78.0	0.0	732.2	87.5	0.8
29	0.0	80.5	80.2	1315.0	68.1	0.8
Total	437.9	1341.4	3713.2	6734.3	2294.4	413.9

A.2. Heat supply capacity

Table A.2 – Installed heat supply capacity in each Energy Hub for 2015

Energy Hub	Installed heat supply capacity (MW_{th})					
	Heat Pumps (air and ground source)	Gas Boiler	Resistive Heating	Oil Boilers	Biomass Boilers	Gas CHP
1	1.7	274.1	34.2	40.5	0.4	0.2
2	2.6	412.3	51.5	60.9	0.7	0.3
3	1.3	209.2	26.1	30.9	0.3	0.1
4	3.4	539.0	67.3	79.6	0.9	0.4
5	6.3	1009.8	126.1	149.2	1.6	0.7
6	4.5	725.6	90.6	107.2	1.2	0.5
7	3.0	481.4	60.1	71.1	0.8	0.3
8	0.5	83.0	10.4	12.3	0.1	0.1
9	2.2	355.7	44.4	52.5	0.6	0.2
10	13.0	2078.0	259.6	307.0	3.3	1.5
11	15.5	2478.4	309.6	366.2	4.0	1.7
12	7.9	1267.7	158.4	187.3	2.0	0.9
13	14.4	2308.9	288.4	341.1	3.7	1.6
14	8.6	1374.2	171.7	203.0	2.2	1.0
15	10.0	1606.8	200.7	237.4	2.6	1.1
16	5.2	833.8	104.2	123.2	1.3	0.6
17	11.7	1875.9	234.3	277.2	3.0	1.3
18	33.0	5288.5	660.6	781.4	8.5	3.7
19	3.2	506.9	63.3	74.9	0.8	0.4
20	12.4	1989.9	248.6	294.0	3.2	1.4
21	6.5	1036.6	129.5	153.2	1.7	0.7
22	12.7	2036.2	254.3	300.8	3.3	1.4
23	10.5	1683.7	210.3	248.8	2.7	1.2
24	8.9	1418.1	177.1	209.5	2.3	1.0
25	37.1	5947.1	742.9	878.7	9.6	4.2
26	4.1	657.0	82.1	97.1	1.1	0.5

27	3.6	573.1	71.6	84.7	0.9	0.4
28	19.7	3147.4	393.1	465.0	5.1	2.2
29	11.1	1783.5	222.8	263.5	2.9	1.3
Total	274.7	43981.7	5493.8	6498.4	70.6	30.9

Appendix B: Cooling water source and cooling method used in power generation plants in the CGEN model

Table B.1 – Power stations in the CGEN model characterised by cooling water source and cooling type used (Byers et al., 2016; Macknick et al., 2012) (Key: SW – Sea Water, TW- Tidal Water, AC- Air Cooled, and FW – Fresh Water)

Power station name	Capacity (MW)	Type	Cooling source	Cooling type
Aberthaw B	1586	Coal	SW	Open loop
Aberthaw GT	51	GT/OCGT	AC	Air cooled
Baglan Bay	510	CCGT	TW	Evaporative
Ballylumford B	540	GT/OCGT	AC	Air cooled
Ballylumford B OCGT	116	GT/OCGT	AC	Air cooled
Ballylumford C	616	CCGT	SW	Open loop
Barking	1,000	CCGT	TW	Open loop
Barry	230	CCGT	AC	Air cooled
Belvedere	70	Waste	AC	Air cooled
Blackburn Mill	60	CCGT	FW	Hybrid
Bridestones Carrington	860	CCGT	FW	Evaporative
Bristol Dock	100	Biomass	TW	Evaporative
Burghfield	47	CCGT	FW	Open loop
Carrington	380	CCGT	FW	Evaporative
Castleford	56	CCGT	FW	Open loop
Charterhouse St Citigen London	31	GT/OCGT	AC	Air cooled
Chickerell	45	GT/OCGT	AC	Air cooled
Cockenzie [e]	1152	Coal	SW	Open loop
Connahs Quay	1380	CCGT	TW	Hybrid
Coolkeeragh	53	GT/OCGT	AC	Air cooled
Coolkeeragh	408	CCGT	TW	Open loop
Corby	401	CCGT	AC	Air cooled
Coryton	800	CCGT	AC	Air cooled
Cottam	2,008	Coal	TW	Evaporative

Cottam Development Centre	390	CCGT	TW	Hybrid
Cowes	140	GT/OCGT	AC	Air cooled
Damhead Creek	800	CCGT	AC	Air cooled
Deeside	515	CCGT	TW	Hybrid
Derwent	228	CCGT CHP	FW	Evaporative
Didcot A [e]	1958	Coal	FW	Evaporative
Didcot B	1430	CCGT	FW	Hybrid
Didcot B	120	CCGT	FW	Evaporative
Didcot GT	100	GT/OCGT	AC	Air cooled
Drakelow	1,220	CCGT	FW	Evaporative
Drax	3,870	Coal	TW	Evaporative[1]
Drax GT	75	GT/OCGT	AC	Air cooled
Dungeness B	1,040	Nuclear	SW	Open loop
Eggborough	1,960	Coal	FW	Evaporative
Elean	38	Biomass	AC	Air cooled
Enfield	408	CCGT	AC	Air cooled
Fawley [e]	968	Oil-ST	TW	Open loop
Fawley GT	68	GT/OCGT	AC	Air cooled
Fellside CHP	180	CCGT CHP	FW	Hybrid
Ferrybridge C [e]	1960	Coal/Biomass	FW	Evaporative
Ferrybridge GT	34	GT/OCGT	AC	Air cooled
Fiddler’s Ferry [e]	1961	Coal/Biomass	TW	Evaporative
Fiddler's Ferry GT	34	GT/OCGT	AC	Air cooled
Gateway energy centre	900	CCGT	AC	Air cooled
Glanford Brigg	260	CCGT	FW	Evaporative
Grain	1320	CCGT CHP	TW	Evaporative
Grain [e]	1300	GT/OCGT	AC	Air cooled
Grain GT	55	GT/OCGT	AC	Air cooled
Great Yarmouth	420	CCGT	TW	Open loop
Hartlepool	1,180	Nuclear	TW	Open loop
Hatfield Park 1	450	CCGT	FW	Evaporative
Hatfield Park 2	450	Coal	FW	Evaporative
Heysham 2	1,220	Nuclear	TW	Open loop
Heysham1	1,160	Nuclear	SW	Open loop
Hinkley Point B [e]	870	Nuclear	SW	Open loop
Hinkley Point C	3620	Nuclear	TW	Open loop
Hunterston B [e]	890	Nuclear	SW	Open loop
Immingham CHP	1,240	CCGT CHP	TW	Hybrid
Indian Queens	140	GT/OCGT	AC	Air cooled
Ironbridge [e]	940	Coal	FW	Evaporative

Isle of Grain	1,260	CCGT	TW	Open loop
Keadby	710	CCGT	TW	Open loop
Keadby GT	25	GT/OCGT	AC	Open loop
Killingholme A	665	CCGT	TW	Air cooled
Killingholme B	900	CCGT	TW	Hybrid
Kilroot	520	Coal	SW	Open loop
Kilroot OCGT	142	GT/OCGT	AC	Air cooled
King's Lynn	99	CCGT	AC	Air cooled
Kingsnorth [e]	1940	Coal	TW	Open loop
Kingsnorth GT	34	GT/OCGT	AC	Air cooled
Knapton	42	GT/OCGT	AC	Air cooled
Langage	905	CCGT	AC	Air cooled
Little Barford	714	CCGT	FW	Evaporative
Little Barford GT	17	GT/OCGT	AC	Open loop
Littlebrook D [e]	1370	Oil-ST	TW	Open loop
Littlebrook GT	105	GT/OCGT	AC	Air cooled
Longannet	2304	Coal	TW	Open loop
Lostock	60	Waste	AC	Air cooled
Marchwood	842	CCGT	TW	Open loop
Medway	688	CCGT	TW	Evaporative
MGT Teesside	295	Biomass	AC	Air cooled
Oldbury	424	Nuclear	TW	Open loop
Pembroke	2180	CCGT	TW	Open loop
Peterborough	405	CCGT	AC	Air cooled
Peterborough Fengate	79	Biomass	AC	Air cooled
Peterhead	1180	CCGT	SW	Open loop
Port Talbot Docks	350	Biomass	AC	Air cooled
Ratcliffe	1960	Coal	FW	Evaporative
Ratcliffe GT	34	GT/OCGT	AC	Air cooled
Rocksavage	810	CCGT	FW	Evaporative
Roosecote	229	CCGT	SW	Open loop
Rugeley	1006	Coal	FW	Evaporative
Rugeley GT	50	GT/OCGT	AC	Air cooled
Rye House	715	CCGT	AC	Air cooled
Saltend	1200	CCGT	TW	Evaporative
Sandbach	50	CCGT	FW	Evaporative
Seabank 1	812	CCGT	TW	Hybrid
Seabank 2	410	CCGT	TW	Hybrid
Seal Sands	1,020	CCGT CHP	AC	Air cooled

SELCHP (South East London CHP)	32	Waste	AC	Air cooled
Severn	848	CCGT	AC	Air cooled
Shoreham	400	CCGT	TW	Open loop
Shotton	210	CCGT CHP	AC	Air cooled
Sizewell B	1,191	Nuclear	SW	Open loop
Slough	61	Biomass	FW	Evaporative
South Humber Bank	1,285	CCGT	TW	Open loop
Spalding	880	CCGT	AC	Air cooled
Stallingborough	65	Biomass	FW	Evaporative
Staythorpe C	1724	CCGT	FW	Evaporative
Steven's Croft	50	Biomass	AC	Air cooled
Stornaway	19	Oil-ST	SW	Open loop
Sutton Bridge	819	CCGT	AC	Air cooled
Taylor's Lane GT	132	GT/OCGT	AC	Air cooled
Teeside CCGT	1875	CCGT	TW	Evaporative
Teeside Power station	45	CCGT	FW	Evaporative
Thetford	39	Biomass	AC	Air cooled
Thornhill	50	CCGT	FW	Open loop
Tilbury B [e]	750	Biomass	TW	Open loop
Tilbury Docks	60	Biomass	AC	Air cooled
Tilbury GT	68	GT/OCGT	AC	Air cooled
Torness	1,190	Nuclear	SW	Open loop
Uskmouth	363	Coal/Biomass	TW	Hybrid
West Burton	2,012	Coal	TW	Evaporative
West Burton CCGT	1270	CCGT	TW	Evaporative
West Burton GT	40	GT/OCGT	AC	Air cooled
West marsh road Spalding expansion	900	CCGT	AC	Air cooled
Willington C CCGT	2400	CCGT	FW	Evaporative
Willington C OCGT	400	OCGT	AC	Air cooled
Wilton 10	38	Biomass	TW	Hybrid
Wilton GT 2	42	GT/OCGT	AC	Air cooled
Wilton Power Station Coal/biomass	150	Coal/Biomass	FW	Evaporative
Wilton Power Station Gas	130	GT/OCGT	FW	Air cooled
Wylfa [e]	490	Nuclear	SW	Open loop

Appendix C: Oxford-Cambridge Arc case study data calculations

C.1. Energy supply capacity data for the electricity transmission system and Energy Hubs excluding the Arc region.

Table C.1 – Installed electricity generation capacities for the national electricity transmission system and Energy Hubs (excluding the arc region).

Generation Type	**Generation Capacity – GW**		
	2015	**2030**	**2050**
Transmission			
Oil	0.8	0.4	0.1
CCGT with Carbon Capture and Storage (CCS)	0.0	6.1	11.6
Coal	13.8	0.0	0.0
Gas (CCGT + OCGT)	28.9	15.7	5.2
Hydro	1.2	1.3	1.3
Pumped hydro	2.8	4.7	5.9
Interconnectors	4.2	15.2	21.2
Other (tidal and marine)	0.0	3.1	5.8
Nuclear	9.0	11.8	15.8
Onshore wind	5.4	11.6	15.2
Offshore wind	4.3	34.0	54.2
Solar	0.5	0.7	0.9
Battery	2.7	2.7	2.7
Total	*73.5*	*107.2*	*139.7*
Distribution - Excluding capacity for the arc region			
Gas (non-CHP)	1.3	3.1	4.1
Onshore wind	4.0	7.4	9.9
Offshore wind	0.5	0.7	0.8
PV	12.3	28.4	40.9
CHP gas	4.9	4.4	4.1
Oil (diesel etc.)	0.6	0.2	0.0

Biomass other	2.6	2.8	2.4
Biomass CHP	0.1	1.2	1.9
Waste other	0.8	1.0	1.0
Waste CHP	0.5	0.7	0.9
Fuel cells	0.0	0.002	0.003
Vehicle to grid	0.0	4.2	8.0
Storage (battery)	0.001	6.0	10.7
Other	0.012	1.0	1.7
Total	*27.5*	*61.3*	*86.1*
Total capacity	**101.1**	**168.5**	**225.8**

C.2. Example investment cost calculation for the Baseline Scenario

The investment costs calculated for the Baseline scenario across all Energy Supply Strategies are presented below. The total investment costs for (a) electricity and heat supply capacity, and (b) network expansion was calculated.

C.2.1. Investment cost calculation of electricity and heat supply capacity

<u>Electricity generation capacity investments</u>

Investment costs were calculated for the new generation capacity added to Arc Energy Hubs. The equivalent annualised costs(C^{eq}) for an investment C $(£/MW)$ were calculated for an annuity rate of r and a lifespan of y, using Equation C.1.

$$C^{eq}\left(\frac{£}{MW}\right) = C \times \left(\frac{r}{1 + \frac{1}{(1+r)^y}}\right) \tag{C.1}$$

The annualised cumulative investment cost calculations include an annuity rate of 7.5% that assumes a 20-year lifespan for new assets. Table C.2 shows the annualised cumulative investment cost calculations made for the new electricity generation capacity for the Electric Strategy.

Table C.2 – Total annualised cumulative investment costs for electricity generation capacity for the Electric Strategy in Baseline Scenario

Generation Asset Type	Investment Cost (ETI, 2017b) C_e^I (M£/MW$_e$)	Cumulative new capacity added by 2050 P^{new} (MW$_e$)	Total annualised cumulative investment cost = $C_e^I \times P^{new} \times C^{eq} \times 20$ (M£)
Oil	1	0.0	0.0
Gas (non-CHP)	0.4	253.3	198.8
Wind Onshore	0.75	205.4	302.3

Wind Offshore	1	0.0	0.0
PV	0.6	5953.0	7007.4
CHP gas	0.5	0.0	0.0
CHP biomass	1	217.3	426.2
CHP waste	2.5	64.5	316.4
Fuel Cells	1.5	0.3	0.8
Vehicle to Grid	0	814.3	0.0
Storage (battery)	0.25	1711.3	839.3
Waste Other	1	29.5	57.8
Biomass Other	1	29.4	57.6
Total			**9206.7**

A similar calculation was made for the new heat supply capacity added to the Arc Energy Hubs. Table C.3. shows the calculated annualised cumulative costs of new heat supply capacity for the Electric Strategy.

Table C.3 – Annualised cumulative investment cost of new heat supply capacity for the Electric Strategy in the Baseline Scenario

Heat supply technology type	Investment Cost (ETI, 2017b) C_{th}^{I} (M£/MW$_{th}$)	Cumulative new capacity added H^{new} (MW$_{th}$)	Total annualised cumulative cost (M£) $= C_{th}^{I} \times H^{new} \times C^{eq} \times 20$
Biomass Boiler	0.45		
Biomass Boiler-DH	0.3		
Biomass CHP-DH	1.5		
Electric Boiler	0.2	702.8	275.8
Electric Boiler-DH	0.21		
Gas Boiler	0.15		
Gas Boiler-DH	0.065	171.0	21.8
Gas CHP-DH	1.5	341.9	1006.2
Heat Pump	0.5	1696.8	1664.4
Heat Pump-DH	0.3	158.9	93.5
Hybrid HP	0.8		
Hybrid HP-DH	0.6	855.9	1007.5
Hydrogen Fuelcell-DH	0.5		
Hydrogen Heatpump	0.9		
Hydrogen Boiler	0.25		
Oil Boiler	0.18		
Resistive Heating	0.175	243.6	83.6
Waste CHP -DH	2		
Total			**4152.8**

Table C.4 – Annualised cumulative costs of new heat supply capacity for the rest of the Energy Supply Strategies in the Baseline Scenario.

Heat supply technology type	Total annualised cumulative investment cost (M£)		
	Heat Networks	Geen Gas	Unconstrained
Biomass Boiler	0.0	0.0	11.7
Biomass Boiler-DH	0.0	0.0	1760.1
Biomass CHP-DH	12593.6	4993.2	2309.6
Electric Boiler			
Electric Boiler-DH			
Gas Boiler			
Gas Boiler-DH	111.5	0.0	82.4
Gas CHP-DH	18094.7	0.0	648.4
Heat Pump	651.0	313.2	1381.8
Heat Pump-DH			
Hybrid HP	0.0	0.0	1385.3
Hybrid HP-DH	0.0	227.2	1890.8
Hydrogen Fuelcell-DH	0.0	1126.0	0.0
Hydrogen Boiler	0.0	1437.4	0.0
Oil Boiler			
Resistive Heating			
Waste CHP -DH	16889.8	0.0	1423.2
Total	**48340.5**	**8097.0**	**10893.2**

C.2.2. Investment cost calculation for network expansion

The network capacities required to supply electricity, natural gas, heat and hydrogen energy were determined. The total network capacity was taken as the total energy supplied through technologies in the Arc Energy Hubs excluding the technologies installed at the consumer end (e.g. gas boilers, rooftop PV etc.). Investment costs were calculated as given in Table C.5 for the additional network capacity required, similar to the investment cost calculations for electricity and heat supply capacity.

Table C.5 – Annualised cumulative investment cost of new network capacity for the Electric Strategy in the Baseline Scenario

Network Type	Investment Cost (ETI, 2017b) C_N^I (£/MWh)	Cumulative new network capacity required N^{new} (MWh)	Total annualised cumulative cost (B£) $= C_N^I \times N^{new} \times C^{eq} \times \frac{20}{10^9}$
Heat	911		
Natural Gas	130		
Electricity	110	66574	14.36
Hydrogen	200		

Table C.6 – Annualised cumulative costs of new network capacity for the rest of the Energy Supply Strategies in the Baseline Scenario.

Network Type	Total annualised cumulative investment cost (B£)		
	Heat Networks	Green Gas	Unconstrained
Heat	45.2	8.8	29.7
Natural Gas			
Electricity	0.6	0.3	5.3
Hydrogen	0	5.9	0

Appendix D: Error analysis for the linear approximation of wind turbine power output

Wind Turbine details (Vestas, 2017) used are given below.

Wind turbine rated capacity, P_k^{rated}	: 2MW
Rated wind speed, v^{rated}	: 11m/s
Cut-in wind speed, v^{cut-in}	: 4m/s
Cut-off wind speed, $v^{cut-off}$	: 20m/s
The swept area of the rotor, A_k	: 6362m^2

Air density ρ is taken as 1.225kg/m^3, and the power coefficient C_p is taken as 0.45. When wind speed v_t is $v^{cut-in} \leq v_t \leq v^{rated}$, the power output from the wind turbine $P_{k,t}$ is calculated from,

$$P_{k,t} = C_p \times \frac{1}{2} \times \rho \times A_k \times v_t^3 \quad \text{D.1}$$

And the linear approximation used in the model calculates the power output by,

$$P_{k,t} = \left(\frac{v_t - v^{cut-in}}{v^{rated} - v^{cut-in}} \right) P_k^{rated} \quad \text{D.2}$$

Figure D.1 shows the comparison between actual and linearly approximated power output curves.

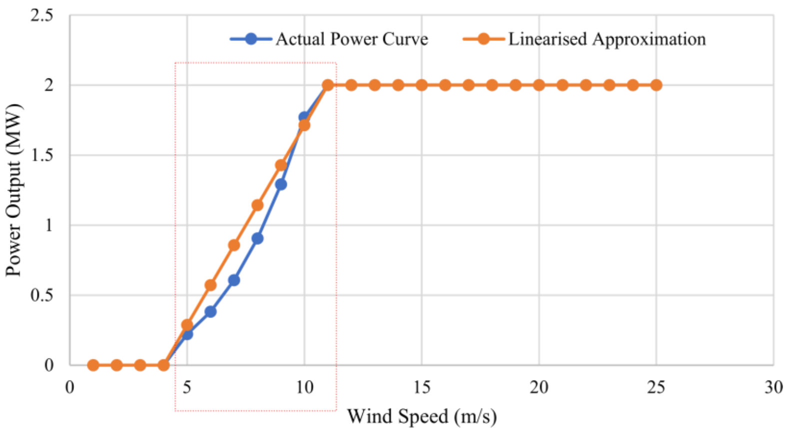

Figure D.1 – Wind power vs wind speed curve comparison between actual power curve (Given by Equation D.1) and the linear approximation (given by the Equation D.2) used in the model.

Table D.1. Calculated error when wind speed v_t is $v^{cut-in} \leq v_t \leq v^{rated}$ using the linear approximation.

Wind Speed (m/s)	Actual power output (MW) given by Equation D.1	Linearised approximation for power output (MW) given by Equation D.2	error%
4	0	0	0
5	0.221	0.287	23.11
6	0.382	0.571	33.10
7	0.607	0.857	29.18
8	0.906	1.143	20.72
9	1.290	1.429	9.69
10	1.769	1.714	3.23
11	2	2	0

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