Decarbonising Heat and Transport: Impacts on Local Electricity Systems

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Abstract

There is an increasing need to decarbonise both heating and transport sectors in the United Kingdom (UK), and the uptake of low carbon technologies (LCTs) will be central in achieving this. However, the uptake of LCTs is expected to pose significant planning and management challenges for distribution network operators (DNOs) in the coming decades as the impact of LCTs on electricity distribution networks varies both spatially and temporally, and is driven by the diversity in technology type, consumer behaviour, variable weather patterns, variation of the building stock and the incumbent network assets. In recognition of this diversity and household energy variability, LCT adoption and utilisation will be influenced by the distribution of socio-economic factors within a local area. This, in turn, has the potential to have varying impacts on distribution networks across different regions. Therefore, to inform decision making, and to 'better' quantify place-based LCT impact and the value of local flexibility, there is a requirement to understand the impact LCTs will have on distribution network infrastructure across diverse geographical areas with consideration for socio-technical and socio-spatial dimensions. This research, which is informed by unique access to distribution network infrastructure data for the entire north of Scotland, presents three approaches to explore key research questions within this theme, summarised as follows:

1. A high-resolution assessment methodology that enables assessment of electrified heat and transport impact on transformer headroom at scale using socio-economic indicators to inform the application of LCT consumption data. This includes mapping of spatially linked datasets to identify relationships between consumption and social deprivation. These relationships are then used as inputs to a heat pump (HP) modelling methodology that couples two methods of converting gas demand to equivalent electrical heat demand. This approach is compared with a generalised trial data approach to ascertain the impact of incorporating socio-economic elements.

2. A scalable approach to localised low voltage (LV) network and LCT impact modelling that

couples two modelling methods: a LV network model development methodology and a LCT impact assessment methodology which accounts for both the electrification of heat and transport demand. The methodology extends the existing HP modelling method and similarly includes battery electric vehicle (EV) charging which is based on charging behaviour in the form of charging diaries showing the combined effect of different LCTs. This is demonstrated on spatially explicit LV network models through quantification of LCT network impact against key network assessment metrics.

3. A method to translate narratives on energy demand futures in heating and transport to impacts on local electricity systems, enabling quantification of the stress placed on key infrastructure and the ability of those demands to act 'flexibly' in supporting the renewables-dominated generation mix necessary to achieve energy system decarbonisation at pace.

The findings are considered from the perspective of the DNO and other key stakeholders to demonstrate the value in spatial and temporal high-resolution modelling, emphasising a need to consider the combined impact of electrified heat and transport in future network investment planning.

Declaration

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

Connor McGarry, November 2023

Prologue

Before delving into the detailed research, it is first considered that a broad contextual reflection of the past several years would help to summarise the pace of change with regards to the continuously evolving ecological crises and wider ongoing decarbonisation efforts that continue to have an impact on the electricity system.

The PhD began in October 2019, shortly after the outbreak of COVID-19 in January 2020 would set in motion a series of events unseen before by modern-day civilisation. For only the sixth time in human history, on 30 January 2020, the World Health Organisation declared the COVID-19 virus outbreak to be a *"public health emergency of international concern"* and on 11 March 2020 the outbreak would be characterised as a *"pandemic"* [1]. On 23 March 2020, it was announced that the UK would enter the first *"lockdown"* where 'non-essential' businesses and schools would close and working from home would be practised [2]. With a reduction in social interaction and with significant changes to standard working practices, noticeable differences in electricity usage were reported [3] and on 28 June 2020 the lowest ever national demand of 13.4 GW was recorded for Great Britain (GB) [4]. The world's first COVID-19 vaccination was administered on 8 December 2020 [5] and by 10 August 2022 an estimated 67.2% of the world's population have received at least one dose of a COVID-19 vaccination with an estimated 12 billion doses administered globally [6], [7]. The scale of this achievement in such a short period of time is a testament to the scientific community and to human endeavour. However, despite this, humanities largest existential threat remains.

Since the beginning of this research, an increasing global average temperature and rising sea levels amongst other climatological factors has fuelled a number of high-profile climate related events that serve as stark reminders of the looming climate threat. The Australian summer of 2019-2020 was described as *"the most catastrophic bushfire season ever experienced in the country's history"* where an estimated 19 million hectares was burnt and nearly 3 billion animals killed or displaced [8]. Similarly, wildfires in California made worldwide headlines in

2020 with the 'August Complex Fire' and again in 2021 with 'The Dixie Fire' each being the largest and second largest wildfire in the state's history, respectively [9]. Worldwide flooding events were also frequently reported over the past several years, including in Western Germany in 2021 where it was reported that *"nearly two months-worth of rain fell in just 24 hours"* causing flash floods [10]. Similarly, in the UK, Storm Christoph brought around a months' worth of rainfall in three days and was one of the wettest three-day periods on record for north-west England and North Wales [11]. Flooding events in New South Wales, China and South Sudan [12] also made headlines with extensive damage to infrastructure, widespread evacuation and mass casualties. Other climatic events also caught headlines; the UK seen temperatures exceed 40°C for the first time, with records broken in England, Wales and Scotland [13]. Record temperatures were also observed in Moscow [14] with record-breaking snowfall in Madrid [15]. Additionally, in February 2021, winter storms in Texas led to rolling blackouts for over 4 million customers in an attempt to ration electricity access as demand increased and production capacity reduced [16], [17]. The cascading effect this had on electricity dependent services caused widespread shortages of water, food and heat [16]. These events emphasise the impact climate change has continued to have over the course of this research in altering our environment and driving an increase in extreme weather-related events that have the potential to cause widespread devastation.

To address the growing climate change concern the Climate Change Committee (CCC) (an independent statutory body established under the Climate Change Act 2008 [18]) working in an advisory capacity to the UK government published their net zero report in May 2019 [19] – eight months prior to the beginning of this work – in response to the Intergovernmental Panel on Climate Change Special Report on Global Warming of 1.5°C in 2018 [20]. The CCC's report indicates that net zero greenhouse gases (GHGs) are *"necessary, feasible and cost-effective"* in tackling global climate change and are required to fulfil the UK's signatory commitments to the 2015 Paris Agreement [19], [21]. The report provides recommendations for individual nations of the UK and in September 2019 the Bill for the Climate Change Emissions Reduction Targets Act 2019 [22] was passed by the Scottish Parliament setting the ambitious target of net zero carbon emissions by 2045, with interim emission targets relative to 1990s carbon emission levels of 56% by 2020, 75% by 2030 and 90% by 2040, respectively [22].

Off the back of such policy mandates grows an increasing climate awareness amongst the general population that has continued to grow over the course of this research. According to the Office for National Statistics' Opinions and Lifestyle Survey, in October 2021, 75% of adults in GB said they were worried about the impact of climate change [23]. The highly anticipated Conference of the Parties 26th (COP26) annual summit held in Glasgow 2021 with over 13 days of negotiations between nearly 200 countries gained significant global attention and massively raised climate awareness, and with the summit held within walking distance of the University of Strathclyde, substantial local attention. At the summit, a new global – non-legally binding – agreement was reached; the Glasgow Climate Pact [24]. The primary objective of the pact is to keep 1.5°C alive (current pledges will only limit global warming to about 2.4°C) and to set the climate agenda for the next decade. Some highlights include promises to stop deforestation by 2030, increased financial support for developing countries to make the switch to clean energy and a pledge for the United States (US) and China to cooperate more over the next decade [25]. However, commitments to *"phase down"* rather than *"phase out"* coal have fuelled debate about the urgency of global action with many leaders and campaigners arguing that the commitments fall short of the necessary response [26]. In addition, whilst many companies in the past several years have ramped up investment in sustainability within their business practices to promote a positive climate aware image that aligns with the evolving social perception of a more climate aware culture, the practice of 'green-washing' has also become a common issue [27].

The heightened attention of COP26 also brought significant controversy, particularly with regards to the proposed Cambo oil field off the coast of Scotland [28]. In a similar vein, the controversial Cumbria coal mine has also intensified and fuelled the debate surrounding energy security and climate change [29]. The biggest driver of the energy security debate is undoubtedly the ongoing Russia/Ukraine crisis. Without delving into geo-politics, at a high-level, price volatility, supply shortages, security concerns and economic uncertainty have fuelled *"the first truly global energy crisis"* according to the International Energy Agency (IEA) [30]. However, it has been acknowledged that the crisis presents an opportunity to hasten the transition towards the use of renewable technologies in an attempt to reduce the dependency on fossil-fuelled imports, and to reduce exposure to global volatile fossil fuel markets [31]. In tandem, domestic fossil fuel production is also at the forefront of the debate despite domestic fossil fuels not necessarily equating to lower energy prices for consumers and being at odds with carbon emissions reduction efforts, though being able to provide autonomy during the transition to net zero. In their winter outlook for 2022-23, National Grid Electricity System Operator (NGESO) indicated that consumers could have faced rolling three-hour power cuts in the worst-case scenario [32]. Although this was unlikely as it accounted for extreme escalation of the crisis, it raised further concerns with energy security.

In combination with the fall-out from the global Covid-19 pandemic, the energy price increase associated with the Russia/Ukraine crisis has had a significant effect on inflation impacting all sectors of the economy. This has manifested in a cost of living crisis of significant proportion such that in June 2023, around half (47%) of surveyed adults reported they found it very or somewhat difficult to afford their energy bills, an increase from 37% in June 2022 [33].

Over the course of this research, the uncertainty surrounding the Covid-19 pandemic, the post pandemic economic and societal recovery, both the short- and long-term implications of the UK's exit from the European Union (EU) formally on 21 December 2020 [34], the Russia/Ukraine inspired global energy crisis, the ongoing cost of living crisis and a rapidly increasing need to address ambitious carbon reduction targets in-line with public expectation and acceptance has intensified an already fast paced highly volatile situation. However, despite the pace of change, the cataclysmic uncertainty and the day-to-day volatility across the energy sector, the research presented in this thesis provides a valuable contribution to knowledge and the ongoing decarbonisation efforts that is supported by the current literature and aligned with the requirements of key industrial actors at this time. Narrowing from this contextual reflection, the research presented in this thesis takes a more in-depth view on the role of the electricity system and associated parties in supporting the decarbonisation of the UK's domestic heat and transport sectors which is central to meet legislated net zero targets.

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Table of Contents

List of Figures

List of Tables

Nomenclature

Abbreviations

ABM Agent-based model

ADMD After diversity maximum demand

ANM Active network management

AQ Annual quantity

ASHP Air source heat pump

AVC Automatic voltage control

BaU Business as usual

BEIS Department for Business, Energy and Industrial Strategy

BEV Battery electric vehicle

BFS Breadth first search

CCC Climate Change Committee

CCS Carbon capture and storage

CDF Cumulative distribution function

CHP Combined heat and power

CMZ Constraint managed zone

COP Coefficient of performance

COP26 26th Conference of the Parties

CREDS Centre for Research in Energy Demand Solutions

DER Distributed energy resource

DERMS Distributed Energy Resource Management System

DG Distributed generation

DNO Distribution Network Operator

DSO Distribution System Operator

ENW Electricity North West

EPC Energy Performance Certificate

ESH Electric storage heater

EU European Union

EV Elective vehicle

FCEV Hydrogen fuel cell electric vehicle

FES Future Energy Scenarios

FSO Future System Operator

GB Great Britain

GHG Greenhouse gas

GIS Geographic information system

GSHP Ground source heat pump

GSO Gas System Operator

GSP Grid supply point

HGV Heavy goods vehicle

HP Heat pump

HV High voltage

ICEV Internal combustion engine vehicle

IEA International Energy Agency

IEEE Institute of Electrical and Electronics Engineers

IMD Index of multiple deprivation

LCL Low Carbon London

LCT Low carbon technology

LFDD Low frequency demand disconnection

LHEES Local Heat and Energy Efficiency Strategies

LoM Loss of mains

LPG Liquid petroleum gas

LV Low voltage

LVNS Low Voltage Network Solutions

MV Medium voltage

NEUPA Network headroom, engineering upgrades and public acceptance

NGESO National Grid Electricity System Operator

NGET National Grid Electricity Transmission

NRS National Records of Scotland

NTS National Travel Survey

Ofgem Office of Gas and Electricity Markets

OLTC On-load tap changer

OPF Optimal power flow

PHEV Plug-in hybrid electric vehicle

PLEF Positive Low Energy Future

PV Photovoltaic

RHPP Renewable heat premium payment

RIIO Revenue=Incentives+Innovation+Outputs

SCL Short circuit level

SIMD Scottish index of multiple deprivation

SSEN Scottish and Southern Electricity Networks

STEVE Spatial temporal engine for vehicle fleet evolution

TEAM Transport Energy Air pollution Model

TSO Transmission System Operator

UK United Kingdom

UKPN UK Power Networks

ULEV Ultra low emission vehicle

US United States

V2G Vehicle-to-grid

VOLL Value of lost load

VPP Virtual power plant

VSM Vehicle stock model

VUF Voltage unbalanced factor

WSHP Water source heat pump

Chapter 1

Introduction

1.1 Research Context

In 2019, the UK became the first major economy to legislate for net zero GHG emissions by 2050 [38] and as a step towards reaching this target, in April 2021, committed to reducing emissions by 78% relative to 1990s levels by 2035 [39]. As a devolved nation within the UK, Scotland has set a net zero target for 5 years ahead of the UK's 2050 target, with an interim target of 75% by 2030 [40]. To achieve these highly ambitious targets, a monumental decarbonisation transition that is set to impact all facets of the economy and society is underway. The power system and associated stakeholders have an integral role in this transition and are having to adapt and evolve to accommodate the new technologies and practices necessary to support the decarbonisation effort. Under this theme, the research context for the work presented in this thesis is described in this section.

1.1.1 Decarbonisation in the UK

To fully appreciate the scale of the transition to net zero and the decarbonisation effort required, the extent of the challenge must first be acknowledged. In the UK, the generation of electricity has historically been dominated by carbon intensive fossil-fuelled technologies, which have directly contributed to the high GHG emission levels recorded [41]. However, over the period of 2009 to 2019 electricity supply emissions have decreased by 65% as demonstrated in Figure 1.1 while the carbon intensity of the grid fell from nearly 500 gCO_2/kWh in 2009 to 200 gCO_2/kWh in 2019 [41]. This reduction, in part, can be attributed to an increase in electricity generated from renewable sources. In 2009, electricity generated from variable renewables was 9 TWh (3% of total generation), compared with 73 TWh in 2019 (26%) [41].

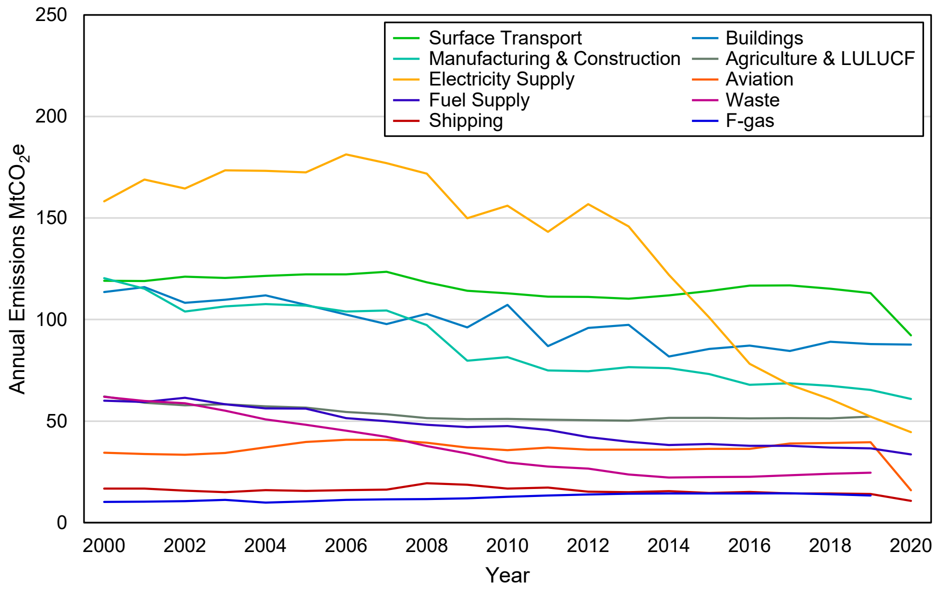


Figure 1.1. Annual carbon dioxide emissions for different sectors from 2000 to 2020 in Britain [41].

In particular, Scotland's electricity sector has seen a substantial reduction in carbon emissions and as a result, Scotland has decarbonised faster than the UK average due to the speed and scale of this reduction, accounting for two-thirds of all GHG emissions reductions since 2008 [42] with renewable sources meeting the equivalent of 98.6% gross electricity consumption in 2020 (up 71.4% since 2009) [43]. This is primarily due to the decommissioning of conventional generating plants such as Cockenzie and Longannet coal-fired power stations coupled with the uptake of onshore and offshore wind farms [44], [45]. Overall, the electricity sector in Scotland has seen a 91% reduction in carbon emissions since 2012 and as of 2017 accounts for less than 3% of the country's carbon emissions [46].

In broad terms this indicates that power sector decarbonisation is at an advanced stage in comparison to other sectors. Further emphasised by the CCC in their 2021 report to parliament stating *"to meet the Sixth Carbon Budget and to deliver the UK's 2030 Nationally Determined Contribution to the Paris Agreement, progress will have to extend quickly beyond the power sector"* [41]. Implying that although power sector decarbonisation remains necessary and the continued growth of Distributed Generation (DG) and larger renewable generation is required, attention must turn towards other key sectors. Namely, the heating and transport sectors which in 2020 account for 51.8% and 24.5% of final energy consumption in Scotland, respectively (note that final energy consumption of electricity is 21%) [47].

The UK has more than 28.6 million homes and over 1.9 million non-residential buildings [48]. It also has the oldest housing stock in Europe where over 52% of homes in England were built prior to 1965 and nearly 20% were built before 1919 (this is comparable to Scotland). Generally, older buildings are less energy efficient in comparison with newer builds. As such, UK households typically use more energy on average than most EU nations. The vast majority of these residential households are connected to the gas network (approximately 85%) using a traditional gas-fired boiler and a wet-based central heating system [39]. The remaining households are unconnected to the gas network and primarily use oil, solid fuel, liquid petroleum gas (LPG) or electric heating as their main source of fuel. Oil and LPG have a higher carbon intensity in comparison with natural gas therefore these households are considered a decarbonisation priority. In Scotland, as of 2020, there are approximately 2.51 million households and around 14% (361,000) of these are not connected to the gas-network [49].

Building emissions come in the form of direct emissions which stem from the combustion of fossil fuels for heat, hot water and cooking, and indirect emissions which come from the use of electricity in buildings. In 2019, it was estimated that heating for buildings contributed 23% towards total UK carbon emissions; with 17% from residential homes, 4% for commercial and 2% from public buildings [50]. With such a significant contribution towards the UK's total emissions, decarbonisation of this sector is vital to achieve the legislated targets. However, the scale, complexity, and costs involved are significant barriers, such that the Department for Business, Energy and Industrial Strategy (BEIS)[1] identified in [52] that *"heating is arguably the most difficult of the major energy consuming sectors of the economy to decarbonise"*. The CCC also indicate in its Sixth Carbon Budget report [53] that to meet decarbonisation targets, an investment of around £250 billion will be required to fully decarbonise homes.

In 2019, domestic transport produced 27% of the UK's total emissions emitting 122 $MtCO_2e$ [54]. A comparative breakdown of the largest contributors between 1990 and 2019 is provided in Figure 1.2.

[1] In February 2023, BEIS was replaced by the Department for Business and Trade, the Department for Energy Security and Net Zero and the Department for Science, Innovation and Technology [51].

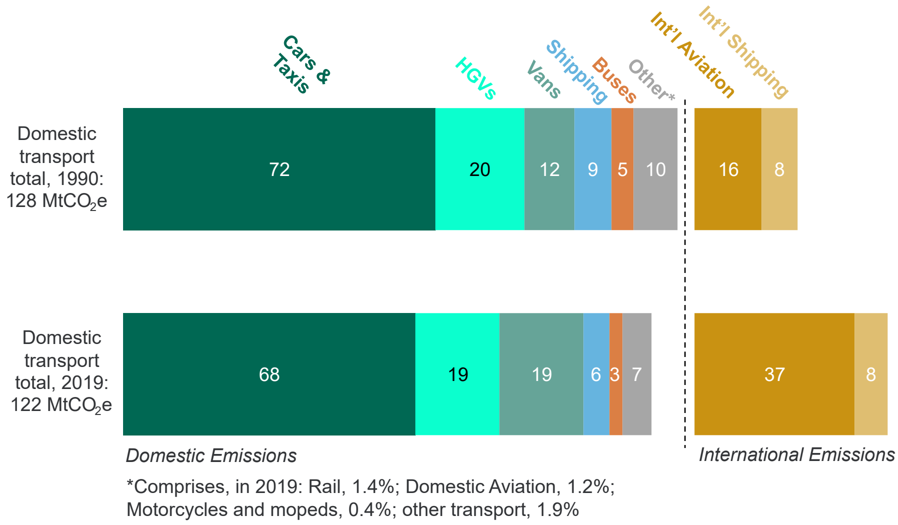


Figure 1.2. Breakdown of transport emissions for 1990 and 2019 [54]. (top) 1990. (bottom) 2019.

The figure identifies that the bulk of domestic transport emissions stem from cars and taxis with internal combustion engines at 68 $MtCO_2e$, accounting for 61% of road transport emissions (decreasing since 1990 primarily due to improvements in vehicle efficiency). This is followed by Heavy Goods Vehicles (HGVs) at 19.5 $MtCO_2e$ (18%) and vans at 19 $MtCO_2e$ (17%) [54]. In Scotland, domestic transport accounted for approximately 25% of emissions at 12 $MtCO_2e$ in 2019 and has been the leading emitter since 2016 [55]. As of 2021, there were approximately 40.3 million licensed vehicles in the UK, 739,000 of these were ultra low emission vehicles (ULEVs) [56] which emphasises the scale of the decarbonisation challenge in the coming decades.

In short, extensive decarbonisation is required in both residential heating and transport sectors. In particular, there is a need to switch from the use of natural gas and other carbon intensive heating options in domestic households to low carbon heating solutions and from carbon intensive internal combustion engine vehicles (ICEVs) to ULEVs. Therefore, to meet the ambitious decarbonisation targets, it is necessary that both transitions occur rapidly[2] and in parallel. This in-part will be achieved through 'electrification' whereby existing technologies and processes that use fossil fuels in both sectors are replaced with low carbon electrically-powered

[2]It is estimated that between now and 2050 emissions from residential buildings must fall to zero at a rate of 3.4% each year based on current emission levels, increasing to a rate six times higher in the next three decades than in the previous three [39].

alternatives. To facilitate this, primarily over the next decade, there will be a requirement for significant investment in new LCTs[3] and electricity system infrastructure amongst investment in wider sectoral decarbonisation efforts e.g. energy efficiency improvements.

1.1.2 The Power System

In principle, the power system facilitates the generation, transmission and distribution of electricity to a variety of different consumers. As such, the power system is integral to the ongoing energy transition and is expected to play a significant role in the transition to net zero. Therefore, in recognition of this role, the following subsections provide a brief overview of the power system in GB and the potential decarbonisation pathways that are set to influence future evolution. This is followed by an overview of the 'energy trilemma' which describes the central challenge with power system investment.

1.1.2.1 The Stakeholders

In 1948, the electricity supply industry in GB was nationalised and subsequently two primary organisations were formed, the Area and Generating Boards. The Generating Boards were responsible for generation and the transmission network, whereas the Area Boards were responsible for the distribution network and demand side servicing [57]. Moving forward, in 1990, the electricity supply industry was privatised, and separate entities were formed to facilitate competition within the sector [57]. From then on, the Transmission System Operator (TSO) and DNOs owned and operated the transmission and distribution networks, respectively. Given the nature of electricity supply infrastructure these entities are natural monopolies and as such, the Office of Gas and Electricity Markets (Ofgem), an independent energy regulator, was formed to promote competition in the energy markets and regulate networks.

In April 2019, the TSO in Britain, National Grid, separated into two businesses; National Grid Electricity Transmission (NGET) and NGESO under the umbrella of the National Grid group, where NGET own the electricity supply infrastructure and NGESO is responsible for balancing supply and demand across GB through the Balancing Mechanism and ancillary service provi-

[3]Note that terms such as DG and LCTs are used with a recognition of their broad applicability and that there is a degree of overlap depending on the specific context they are used in. These terms serve as encompassing descriptors for the various technologies connected to the distribution network. However, as this work focuses specifically on the decarbonisation of heat and transport, in certain contexts the use of LCTs is used to refer solely to the technologies considered in the presented analysis.

sion [58]. Currently in GB, there is a single electricity system operator, NGESO (also the Gas System Operator (GSO)), 3 transmission network companies: NGET, Scottish Hydro Electric Transmission and SP Transmission and 6 DNO groups: Electricity North West (ENW), Northern Powergrid, Scottish and Southern Electricity Networks (SSEN), Scottish Power Energy Networks, UK Power Networks (UKPN) and National Grid after recently acquiring Western Power Distribution.

As of April 2022, the UK government and Ofgem have committed to proceeding with the creation of an 'expert impartial' Future System Operator (FSO) [59]. This operator will have operational independence from government and will adopt a 'whole system' approach within the energy system through responsibilities in operating, strategic network planning, long-term forecasting, and market strategy. Through these roles, the FSO will drive progress towards net zero while maintaining energy security and minimising costs for consumers. The FSO in effect would take an increasingly significant role in shaping the energy system, support policy decision making and drive competition across the energy sector.

1.1.2.2 Transmission and Distribution Networks

Electricity is generated from various sources and supplied to consumers via the transmission and distribution networks. The transmission network is comprised of high voltage links, typically 275-400 kV in England & Wales and 132-400 kV in Scotland, that connect large generators – often situated in remote locations – to load centres, supporting the bulk transfer of power [57]. The distribution network, which operates at lower voltages, typically 33, 11 or 6.6 kV and 400 V (including 132 kV in England & Wales), then conveys this power to consumers. The step-up/-down in voltage is achieved through transformers. The power system is thus essentially made up of networks at various voltages, and so multiple voltage tiers. At higher voltages, the connection between various system components e.g. lines, transformers and switching devices are made at substations. The connection point between the transmission and distribution network is more specifically known as the Grid Supply Point (GSP). Both transmission and distribution networks operate at three-phase with residential demand typically connected via single phase (230 V line-to-phase).

In addition to voltage differences (and associated asset costs) transmission and distribution networks differ significantly in terms of general structure and topology [57]. Distribution networks have significantly more sources and branches in comparison with transmission networks. However, transmission networks have historically been of higher priority given the dependency, risk and cost associated with operating at higher voltages. Transmission network circuits in GB are subject to N−1 conditions according to the Security and Quality of Supply Standard and connections must conform to the Grid Code [60], [61]. Distribution network connections and operators must conform to the Distribution Code [62] and various Engineering Recommendations and Technical Specifications e.g. security of supply is governed by Engineering Recommendation P2/7 [63].

As the decarbonisation of residential heat and transport will be achieved in part through electrification via demand side connected LCTs, this research is primarily focused on the distribution network. Therefore, for distinction, the voltage tiers are defined as follows; EHV for the portion of network above 33 kV, high voltage (HV) for the portion between 33 kV and 11/6.6 kV, and LV for anything at 400 V or below. Primary transformers are responsible for the step-down in voltage from 33 kV to 11/6.6 kV and secondary transformers or distribution transformers are responsible for the step-down in voltage from 11/6.6 kV to 400 V. Although focus is predominantly on the distribution network the wider implications from a whole system perspective are acknowledged.

1.1.3 The Future: Decarbonisation Pathways

The transition to a net zero economy by 2050 is highly uncertain given the scale of the cross sectoral challenges and requirements. In terms of heat and transport decarbonisation, there are a diverse portfolio of end use technologies available to support the transition (some more advanced and mature than others). As such, there is no 'silver bullet' or 'one size fits all' solution and by having such a diverse portfolio of available decarbonisation options there exists significant uncertainty surrounding future pathways which is further complicated by the inherent nature of this particular decarbonisation challenge, in that society is central to the transition and must change the way it demands energy services. This uncertainty has major implications for various parties involved in the transition e.g. local government, policy makers, network operators and local businesses. As such, numerous bodies across the energy systems community have aimed to reduce this uncertainty by creating plausible decarbonisation pathways [53], [64], [65]. The pathways fundamentally differ in terms of their specifics. However, they provide insight into what the transition to net zero may look like. This includes insight into potential sectoral energy demand evolution and subsequent decarbonisation through technological displacement and behavioural changes [66]. NGESO's decarbonisation pathways are published in the form of Future Energy Scenarios (FES) and their FES for 2022 are presented in Figure 1.3.

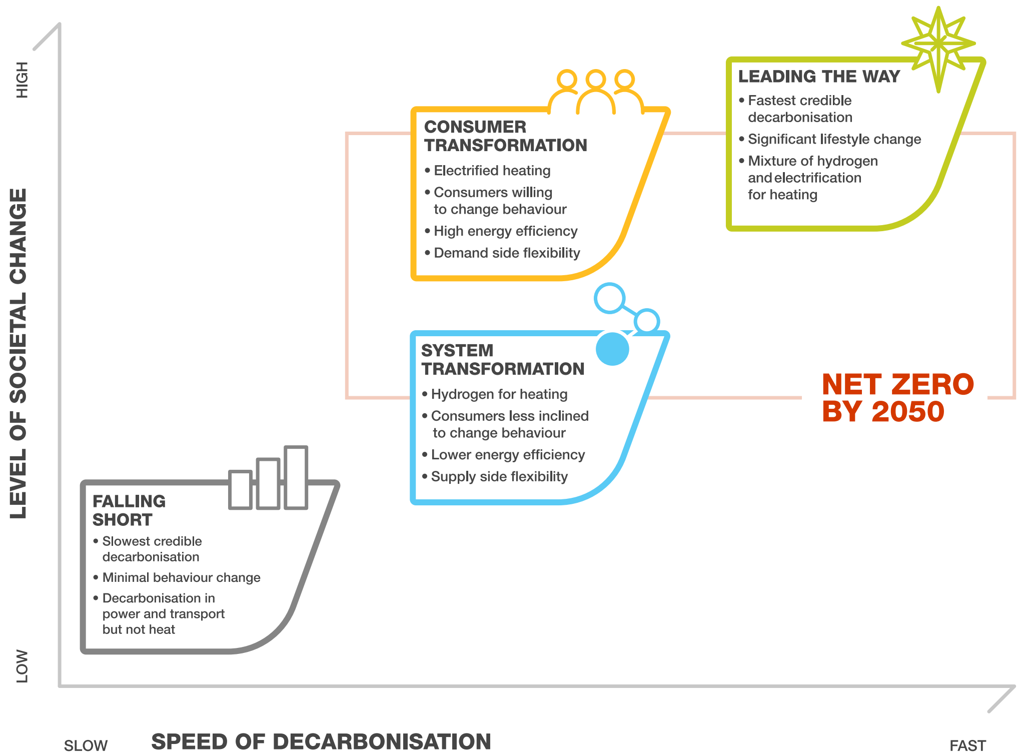


Figure 1.3. NGESO's Future Energy Scenarios 2022 [64].

Of the four published scenarios shown in Figure 1.3 only three meet the 2050 net zero target, these are Consumer Transformation, Leading the Way and System Transformation, with Falling Short failing to meet the target. The scenarios are formed around varying levels of societal change and decarbonisation rates [64]. In comparison, the net zero pathways produced by the Energy System Catapult are designed specifically to explore the extent and effect of energy system decentralisation [65]. In recognition that distribution networks are becoming increasingly decentralised as generation shifts from large scale synchronous generating plant connected to the transmission network to smaller more distributed asynchronous generating units (sources of electricity that are not inherently synchronised with the grid frequency and are typically connected through power electronics which regulate frequency and voltage within acceptable limits) located in closer proximity to demand [67], [68]. This transition fundamentally challenges the conventionally designed uni-directional flow of power, i.e. generation to transmission to distribution, by introducing a more flexible variable flow of power in certain areas of the network [67]. The challenges associated with this evolution are compounded by the connection of variable LCTs to the network. As a result, this evolution is set to introduce a range of network operational, management and planning challenges [67], [69]. Therefore, regardless of the broader transitional pathway taken to net zero, distribution network operation and management is set to become substantially more challenging as distribution networks (and operators) become increasingly more active.

1.1.4 The Energy Trilemma

The overarching role of the electricity system in the transition to net zero is to serve future demands for electricity (whatever that may turn out to be) across all sectors. Therefore, the central challenge of providing a secure and reliable supply remains despite the ongoing changes in how electricity is generated and supplied to end consumers. To achieve this there is a requirement for appropriate investment at sufficiently advanced timescales. How this investment is distributed and allocated must be in keeping with decreasing carbon emissions. As such, there are a distinct set of planning constraints which drive investment decision making and these comprise the ‘energy trilemma’ [70], as demonstrated by Figure 1.4.

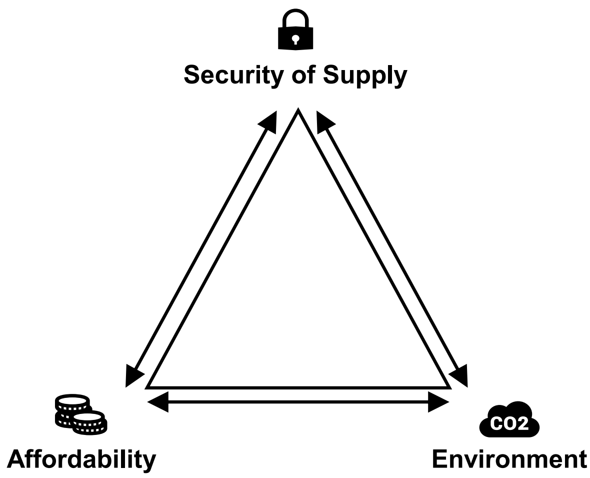


Figure 1.4. Visual representation of the energy trilemma concept [70].

As distribution networks become increasingly more active, and the conventional methods of planning and management are challenged. DNOs are having to adapt and evolve to ensure that they are equipped to manage the increase in demand from LCTs and to provide a secure and reliable supply as consumer dependency on the network increases. This is particularly challenging as network operation becomes increasingly more demanding. Therefore, they are tasked with finding the optimal balance between the energy trilemma vectors such that the network is developed to provide security of supply at an affordable cost to the consumer with respect to the ongoing decarbonisation efforts.

The authors in [71], identify that in addition to the core constraints of the energy trilemma, there exists broader considerations that have the potential to further influence investment decision making. Identifying that there is a requirement to consider the social impacts of electricity investment and the fairness of resource allocation. This underscores the need to ensure that the benefits and burdens of infrastructure investments are distributed equitably among different demographic groups and regions to prevent from disproportionately favouring certain areas or exacerbating existing social inequalities. Understanding the wider societal impacts of such investments will help to ensure that future investments are aligned with broader just-transitional goals and values.

1.1.5 Society and Localisation

Societal diversity (economic or otherwise), combined with climate conditions and buildings drives the spatial and temporal variation in electricity demand that the grid is currently designed to accommodate. Therefore, it is well understood that energy consumption and resulting emissions are unequally distributed [72]. As a consequence, this manifestation translates to the uptake and utilisation of LCTs where different areas at the local-level will have different demand requirements subject to the 'local conditions' (demographic, buildings and climate) of a particular area. For simplicity, this phenomenon is termed as 'localisation' in this work. Whilst it is acknowledged that localisation will have an impact on the rate of LCT uptake and utilisation, at present, it is not yet fully understood what extent different manifestations of local conditions will have on LCTs [73]. Therefore, the uncertainty associated with LCT impact on distribution networks across different geographical areas is exacerbated.

Historically, distribution network complexity has been offset by the low uncertainty associated with conventional load types in that electricity demand has been relatively predictable in terms of shape and magnitude despite the DNO having limited monitoring and visibility of the LV network. Conventional network planning has been reliant on estimating an absolute maximum peak demand, rating assets with the expectation this will satisfy network demand and any moderate future growth. In consideration of diversity within local areas, the DNOs have used relatively simplistic metrics in planning since the 1987 issue of Engineering Recommendation P5 including After Diversity Maximum Demand (ADMD) and the statistical method 'Debut' [74], [75]. As the number of consumers increase, the impact of demand diversity is reduced [74]. This dictates that at higher voltage tiers (with greater numbers of loads connected downstream) the impact of diversity is less prominent than compared with at lower voltage tiers e.g. at a feeder level.

Despite this, the uptake of LCTs is further complicated by the regulatory and policy decision making of different entities (including local government responsible for different regions) that have the potential to influence particular decarbonisation pathways, and the uptake and usage of particular technologies. For example, a mandate of many national government policies is to ensure a just transition and that areas of higher social deprivation using carbon intensive technologies cannot be ignored or 'left behind' in the energy transition as they too will need to decarbonise to achieve net zero in the timescales required [76]. Therefore, the transition to low carbon alternatives will have to be affordable or policy through political and regulatory decisions will be necessary to support those in these areas to realise the legally binding net zero targets. What exactly those decisions will look like and how policy makers and local government will address these national objectives will vary across different regions based on local-area specific requirements. Nevertheless, these decisions will have an impact on electricity system infrastructure though the extent of which still remains unclear. As a result, there is a growing need for targeted socio-technical[4], LCT and infrastructure linked modelling to minimise the uncertainty that subsequently feeds into both DNO planning decision making and that of policy, and local government.

Figure 1.5 summarises the relationship between local conditions, LCTs, the distribution net-

[4]The term 'socio-technical' is used to emphasise the relationship between people and technologies/systems whereas 'socio-economic' is used to account for broader societal structures, such as social classes, demographics, cultural norms and various other aspects of life, including employment status and income distribution. There is naturally some overlap and it is therefore considered that either of these terms can be used to sufficiently capture the societal element within the context of this work.

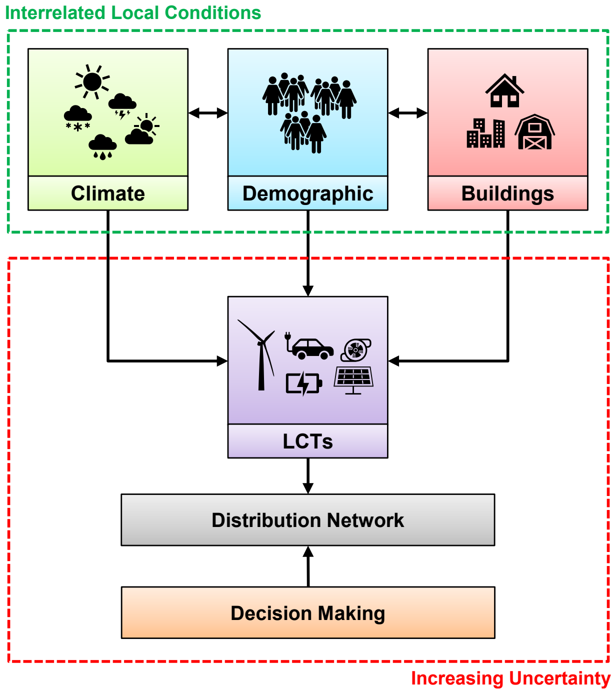


Figure 1.5. High level overview of how interrelated local conditions and LCTs are contributing to an increasing uncertainty in DNO decision making.

work and DNO decision making.

1.1.6 Flexibility in Electricity Demand

Conventionally, the DNO was responsible for distribution network resilience, where they were required to maintain security of supply through asset management and network reinforcement, making decisions based on a limited measurement set [63], [77], [78]. With the electrification of both heat and transport demand, significant investment will be necessary to meet increasing peak demand requirements. However, as with conventional peak demands these increased peak demands are only likely to occur several times each year, which further challenges the cost effectiveness of traditional network reinforcement i.e. reinforcement costs for predominately underutilised assets are exacerbated beyond what is currently acceptable. This introduces the potential for 'smarter' network management through flexible solutions that offset reinforcement costs and manage asset capacity more efficiently. In [79], it is estimated that flexible technologies that deter reinforcement and manage capacity could save the UK energy system £17–40 billion cumulative to 2050. Ofgem have directed that DNOs should be responding to the inherent flexibilities associated with LCTs by exploiting flexible solutions now and across the second round of electricity distribution price controls as set by the Revenue=Incentives+Innovation+Outputs (RIIO) framework [80]. As such, the development of ‘smart’ technologies and an increasing ethos for a ‘flexibility first’ approach, presents an opportunity to defer network reinforcement and the disruption that this brings, whilst providing an opportunity to capitalise on the flexibilities available from distributed assets to maximise infrastructure utilisation and support network operation, benefiting the DNO, industry partners and potentially end consumers [69]. However, Ofgem also express an expectation for DNOs *“to develop their networks in a manner that considers the optimal outcome for the system as a whole”*, e.g. by developing the network with the appropriate balance between the use of flexible solutions and network reinforcement [80]. With this, the concept of local energy systems has formed part of the flexibility versus reinforcement discussion and in April 2022, Ofgem launched a review into local energy system operation [81]. In principle, local energy systems through strategic coordination would see energy managed locally for a local benefit, reducing the dependency on centralised sources of generation and on the delivery chain. With the electrification of heat and transport, flexibility would be instrumental in a local energy system context and therefore the uptake of LCTs are expected to have a significant impact on local energy system operability.

1.2 Research Motivation

There is an increasing need to decarbonise both the residential heating and transport sectors, and electrification through the uptake of LCTs is expected to be central in achieving this. However, whilst research on the impacts of prominent individual LCTs e.g. EVs and HPs on distribution networks is plentiful [82]–[94], works on the combined effects of EVs and HPs on network infrastructure is comparatively scarce with only a handful of published studies. Of the existing studies that consider both EVs and HPs [93], [94], none use socio-economic indicators in forming their analyses at granular resolutions, which has been established as a major driver of household energy consumption [95]–[98] and subsequently a key determinant in influencing the necessary network investment. As such, this has been identified as a considerable research gap and to the author’s knowledge, no work has sought to simulate the combination of EV and HP demand on distribution network infrastructure at scale and at a higher resolution than primary substations, using socio-economic indicators to inform the application of LCT consumption data.

Furthermore, as LCT uptake and utilisation varies both spatially and temporally – a consequence of the inherent diversity associated with local conditions – the uptake of LCTs is increasing demand uncertainty which is challenging the effectiveness of network planning decision making. Therefore, in recognition that many of the LV network modelling techniques that have been developed in the literature have been developed to capture the complexity and disparate nature of LV networks e.g. [99]–[102] and [103]. With a growing appetite to move beyond the modelling of 'generic' LV networks where less emphasis is placed on specific networks and their locale, works such as [94], [104] have identified that the use of network geographic information system (GIS) data has significant LV network modelling potential, generating a number of LV network models that have been used extensively. However, since the creation of these models, and the occasional development of other isolated GIS-network models as in [105], GIS data quality has progressed in line with the need for scalable targeted modelling of specific networks and detailed characterisation of associated local demand with respect to socio-spatial and socio-technical indicators that inform LCT consumption.

In addition, as the distribution network becomes increasingly more active with decentralisation and the increased uptake of inherently flexible and variable distributed assets, the potential of demand flexibility has been well documented [106]–[109]. However, whilst these works have investigated the role and usefulness of demand flexibility, they fail to consider the future evolution of energy service demand as a result of shifting societies, evolving technologies and policies that actively support energy demand reduction in the name of climate change mitigation and promotion of human well-being at the local-level. As previous, they also tend to focus on one low carbon vector (either heat or transport) with the effects of combinational LCT uptake neglected. This is also identified as a considerable research gap and to the author's knowledge, there has been no work on linking pathways in energy demand futures – such as those presented in [110] – to the potential impacts on infrastructure and the value proposition of local energy system flexibility in consideration of both the electrification of heat and transport demand.

1.3 Thesis Contribution

1.3.1 Research Questions and Objectives

The research presented in this thesis provides a contribution to the existing body of knowledge by exploring the following question:

What impact does both the electrification of heat and transport have on local electricity systems and flexibility in network planning?

In doing so, the following sub-questions are considered:

1. How can geospatial and socio-technical analysis support assessment of LCT impact on distribution network infrastructure to inform network and policy decision making?

2. What role does scalable place-based LCT and detailed LV network modelling have in supporting informed LCT impact assessments and local-level decision making for different stakeholders?

3. What impact does different future energy demand narratives have on local electricity systems and demand flexibility?

From these sub-questions, the research objectives are defined as follows:

1. To bridge the gap in understanding on how distribution network assets are affected by LCT uptake in consideration of social and spatial diversity, and to assess the value of this understanding by exploring the ramifications for various stakeholders.

2. To investigate the state-of-the-art with respect to LV network modelling techniques and determine their sufficiency for localised modelling at scale, and to address the limitations of existing modelling techniques for spatially explicit place-based LCT impact analysis.

3. To translate narratives on energy demand futures in heating and transport to impacts on local electricity systems, enabling quantification of the stress placed on key infrastructure and the ability of those demands to act ‘flexibly’ in supporting the renewables-dominated generation mix necessary to achieve energy system decarbonisation at pace.

1.3.2 Overview of Contributions

This thesis presents three novel approaches to explore the identified research questions as follows:

1. A high-resolution[5] assessment methodology that enables assessment of electrified heat and transport impact on transformer headroom at scale using socio-economic indicators to inform the application of LCT consumption data. This includes mapping of spatially linked datasets to identify relationships between consumption and social deprivation. These relationships are then used as inputs to a HP modelling methodology that couples two methods of converting gas demand to equivalent electrical heat demand. This approach is compared with a generalised trial data approach to ascertain the impact of incorporating socio-economic elements.

2. A scalable approach to localised LV network and LCT impact modelling that couples two modelling methods: a LV network model development methodology and a LCT impact assessment methodology which accounts for both the electrification of heat and transport demand. The methodology extends the existing HP modelling method and similarly includes battery EV charging which is based on charging behaviour in the form of charging diaries showing the combined effect of different LCTs. This is demonstrated on spatially explicit LV network models through quantification of LCT network impact against key network assessment metrics.

3. A method to translate narratives on energy demand futures in heating and transport to impacts on local electricity systems, enabling quantification of the stress placed on key infrastructure and the ability of those demands to act ‘flexibly’ in supporting the renewables-dominated generation mix necessary to achieve energy system decarbonisation at pace.

[5] In the context of this work, ‘high-resolution’ relates to the spatial resolution of the analysis though does not explicitly relate to simply ‘zooming-in’, rather extending beyond magnification to enable analysis with not only an increasing level of detail but to capture the relevant complexity of interactions. This analysis allows for examination of the intricate relationships that would otherwise be overlooked in lower-resolution (aggregated) approaches allowing from a more comprehensive understanding of the system behaviour and characteristics.

1.3.3 Publications and Dissemination

The principal contributions of this work are summarised within the following three journal papers which describe the core advancements and findings derived from this thesis.

1. **C. McGarry**, J. Dixon, I. Elders and S. Galloway, "A high-resolution geospatial and socio-technical methodology for assessing the impact of electrified heat and transport on distribution network infrastructure," *Sustainable Energy, Grids and Networks*, vol. 35, pp. 101118, 2023, doi: 10.1016/j.segan.2023.101118.

2. **C. McGarry**, A. Anderson, I. Elders and S. Galloway, "A scalable geospatial data-driven localization approach for modeling of low voltage distribution networks and low carbon technology impact assessment," *IEEE Access*, vol. 11, pp. 64567-64585, 2023, doi: 10.1109/ACCESS.2023.3288811.

3. **C. McGarry**, J. Dixon, J. Flower, W. Bukhsh, C. Brand, K. Bell and S. Galloway, "Electrified heat and transport: energy demand futures, their impacts on power networks and what it means for system flexibility," *Applied Energy*, vol. 360, pp. 122836, 2024, doi: 10.1016/j.apenergy.2024.122836.

In addition to these outputs, several other related research activities have been undertaken:

A. Journal Publications

C. McGarry, S. Galloway and L. Hunter, "Flexible management and decarbonisation of rural networks using multi-functional battery control," *IET Renewable Power Generation*, vol. 16, no. 9, pp. 1955–1968, 2022, doi: 10.1049/rpg2.12507.

A. Anderson, **C. McGarry**, S. Galloway, B. Stephen and S. McArthur, "Scaling of localised electrical heat demand for LV distribution networks using geospatially linked gas demand data," *Applied Energy*, 2023. *(In Review)*

S. Gordon, **C. McGarry** and K. Bell, "The growth of distributed generation and associated challenges: a Great Britain case study," *IET Renewable Power Generation*, vol. 16, no. 9, pp. 1827–1840, 2022, doi: 10.1049/rpg2.12416.

S. Gordon, **C. McGarry**, J. Tait and K. Bell, "Impact of low inertia and high distributed generation on the effectiveness of under frequency load shedding schemes," *IEEE Transactions on Power Delivery*, vol. 37, no. 5, pp. 3752–3761, 2021, doi: 10.1109/TPWRD.2021.3137079.

B. Conference Contributions

C. McGarry, S. Galloway and G. Burt, "Decarbonisation of rural networks within mainland Scotland: in support of intentional islanding," in *the 9th International Conference on Renewable Power Generation*, IET, Dublin, March, 2021, doi: 10.1049/icp.2021.1379.

C. McGarry, S. Galloway and G. Burt, "Renewable dense local systems to support grid operation," *Poster presented at the 2020 Conference of the EPSRC CDT Future Power Networks and Smart Grids*, Glasgow, 2020.

S. Gordon, **C. McGarry** and K. Bell, "The growth of distributed generation in Great Britain and associated challenges," in *the 9th International Conference on Renewable Power Generation*, IET, Dublin, March, 2021, doi: 10.1049/icp.2021.1381.

C. Other Contributions

C. McGarry, J. Dixon and J. Flower "Translating heating and transport energy demand futures into electricity system impacts," *Research presented at the Centre for Research into Energy Demand Solutions in Collaboration: Scotland event*, Edinburgh Climate Change Institute, March, 2023.

C. McGarry, S. Galloway and I. Elders, "The impact of electrified heating and transport on distribution networks and flexible network management," *Research presented to the Scottish Government's Whole System and Technical Policy Unit*, Virtual Platform, 2022.

J. Bowes, S. Galloway and **C. McGarry**, "Geospatial modelling of heat pump uptake on electricity network infrastructure," *ClimateXChange Publications*, 2023, url: https://tinyurl.com/bdrkje5m.

H. Corbett, C. Calvillo Munoz, M. Hannon, P. Anderson, I. Cairns, K. Davies, S. Galloway, G. Hawker, C. MacIver, **C. McGarry**, K. Turner, and R. Yarr, "Scottish Draft Energy Strategy and Just Transition Plan Consultation: University of Strathclyde Response," *University of Strathclyde*, May 2023, url: https://tinyurl.com/ykt85b5b.

1.4 Summary of Chapters

The main body of work is comprised of six chapters including this one; the remaining chapters are described below.

Chapter 2: An Overview of the Decarbonisation of Heat and Transport, and Distribution Network Evolution

This chapter presents an overview of the decarbonisation of heat and transport, and distribution network evolution where the key contextual and motivational elements raised are explored in greater detail. The chapter initially explores the decarbonisation of heat where an extensive breakdown of the technologies and challenges involved in the transition to low carbon heating is provided. A similar overview for the decarbonisation of transport is then provided, with a specific emphasis on surface transport. The focus is then shifted to distribution networks and the existing operation, planning and management practices which is followed by a detailed overview of distribution network and DNO evolution, this includes the transition from passive to active distribution networks and the associated operation, planning and management implications, the challenges with decentralisation and the uptake of DG, and the transition from DNOs to Distribution System Operators (DSOs). This is followed by an overview of flexibility in the electricity system including: flexibility in 'smarter' grids, flexibility as a service, and flexibility in local energy systems.

Chapter 3: A High-Resolution Geospatial and Socio-Technical Methodology for Assessing the Impact of Electrified Heat and Transport on Distribution Network Infrastructure

This chapter seeks to answer *how can geospatial and socio-technical analysis support assessment of LCT impact on distribution network infrastructure to inform network and policy decision making?* The work carries out mapping of spatially linked gas demand and socio-technical/-spatial datasets and then through analysis, identifies relationships between gas consumption and social deprivation/affluence. The relationships support generalised socio-technical analysis in the absence of sufficiently granular metadata and are used to support spatial and socio-sensitive LCT modelling. A localised HP modelling methodology that couples two established methods of converting gas demand to equivalent electrical heat demand is then incorporated where the developed relationships between gas demand and social deprivation are used as inputs to the modelling. The benefits of this approach are shown by comparison with a generalised HP modelling approach that uses raw trial data. In addition to the localised HP modelling, the work incorporates modelling of EVs where EV charging schedules are synthesised from UK National Travel Survey (NTS) data. This allows for a combined infrastructure assessment that accounts for both the electrification of heat and transport in consideration of socio-economic indicators. The methodology is applied to a fleet of over 4,000 secondary transformers distributed across the north of Scotland and a subset are used to inform the analysis. Findings are then analysed primarily from the perspective of the incumbent DNO but the implications and value of such modelling capabilities for other stakeholders e.g. policy makers and local authorities[6] are also discussed. Findings from this analysis also provide insights into the value of localised modelling with respect to socio-technical analysis.

Chapter 4: A Scalable Geospatial Data-Driven Localisation Approach for Modelling of Low Voltage Distribution Networks and Low Carbon Technology Impact Assessment
This chapter seeks to answer *what role does scalable place-based LCT and detailed LV network modelling have in supporting informed LCT impact assessments and local-level decision making for different stakeholders?* The work builds on the established recognition that the heterogeneity of distribution networks, consumer demographic and building stock across a geographic area presents a complex set of interdependence that requires consideration when developing network modelling capabilities. Therefore, a scalable data-driven modelling methodology is presented that includes the mapping and integration of external spatially explicit datasets with network GIS data and builds on the existing works used to develop 'generic-GIS' LV network models by including a local spatial reference that is used to support high-resolution place-based analysis and granular localised LCT demand modelling. A localised LV network assessment methodology is then presented which incorporates modelling of both EVs and HPs. Where existing works generally infer heat demand from metadata for HP modelling, the work in this chapter expands on the approach used in the previous chapter to include enhanced representation of targeted areas. The developed methodology takes a statistical approach to LCT impact assessment. The value of this modelling capability is outlined in terms of its ability to inform stakeholder decision making.

[6] In Scotland, there are 32 local authorities often referred to as 'Councils'. They are responsible for public services within their respective areas. They receive funding from the Scottish government whilst operating independently and raise additional income via Council Tax, a locally variable domestic property tax, and Business Rates, a non-domestic property tax [111].

Chapter 5: Electrified Heat and Transport: Energy Demand Futures, Their Impacts on Distribution Networks, and What It Means for System Flexibility

This chapter seeks to answer *what impact does different future energy demand narratives have on local electricity systems and demand flexibility?* Existing demand scenarios, as created by the Centre for Research in Energy Demand Solutions (CREDS) in their Positive Low Energy Futures (PLEFs), are used to drive spatially explicit modelling of the uptake of electrified transport and heating and temporally explicit modelling of the electricity demand of these technologies for a local geography. An electricity distribution network model that serves households in the local geography is then used as basis to examine the impacts of varying demand scenarios on electricity system infrastructure. An unbalanced optimal power flow (OPF) formulation that enables smart EV charging and vehicle-to-grid (V2G) also forms part of the methodology and is used to investigate the impact of these future demand scenarios on the potential of flexibility in electricity demand. As with previous chapters, findings are then analysed primarily from the perspective of the incumbent DNO but the implications and value of such modelling capabilities for other stakeholders are also discussed.

Chapter 6: Conclusion

This chapter concludes the work presented in this thesis and revisits the key contributions developed through the research with respect to the overarching research question *what impact does both the electrification of heat and transport have on local electricity systems and flexibility in network planning?* Recommended future research is also provided.

1.5 Chapter Summary

This chapter has presented the research context and motivation for undertaking the work described in this thesis. The chapter has also presented the primary contributions of the research with respect to the key research questions and objectives that have been identified. The academic research publications and dissemination activities carried out during the course of this research have also been presented.

Most importantly, it has been established that whilst existing works in electrified heating and transport are typically siloed by sector, there is a growing need to address knowledge gaps associated with combined electrified heating and transport, and to progress the accompanying methodologies and modelling techniques used to inform stakeholder decision making in this space.

In the next chapter, a detailed overview of distribution network evolution and the associated challenges for DNOs is presented to further establish the contextual basis of this thesis.

Chapter 2

An Overview of the Decarbonisation of Heat and Transport, and Distribution Network Evolution

2.1 Decarbonisation of Domestic Heating

As outlined in the previous chapter, there is substantial motivation to decarbonise the residential heating sector in the UK. Therefore, this section describes the primary challenges with doing so and explores the low-carbon heating options available to support the transition. This is then summarised in terms of the potential impact on the power system. To better understand the decarbonisation requirements, the main heating solutions currently in use first must be considered [50]. These are described as follows:

- gas boilers that burn natural gas (primarily methane) supplied via the national gas grid;
- low-efficiency direct electric heating, such as economy-seven or plug-in space heaters, which provide less than one unit of useful heat for every unit of electricity consumed;
- high-carbon oil and LPG boilers, typically with large storage tanks, used predominately by off-gas households; and
- solid fuel, either biomass (wood, wood chippings or pellets) or coal.

Given the carbon intensive nature of these technological heating options there is a need to retrofit low carbon solutions capable of displacing these technologies in existing buildings, whilst also ensuring that new builds are equally equipped with low carbon heating.

2.1.1 Buildings and Occupants

In the decarbonisation of heat, buildings and their occupants have an integral role to play in any future scenario. Building stock characteristics have a direct impact on energy efficiency and subsequently on heat demand, whereas household occupants and their behaviour will also have a direct impact on heating requirements which will vary between different types of occupants.

In the UK, consumers tend to operate space heating intermittently around their daily lives and it is recognised that adjusting a central heating system is the primary method of altering the indoor thermal environment to achieve thermal comfort. However, it is not the sole method and other methods e.g. opening windows to aid cooling or adding additional layers to provide warmth are used to adjust household thermal conditions. Hanmer et al. introduce the concept of 'thermal routines' which are defined as regular patterns in time of heating use and other actions taken to achieve thermal requirements [112]. Recognising that space heating demand is linked to temporal patterns in the home and that these patterns are driven by external social routines. Consumer education and acceptability are also key in the decarbonisation of heat. To support the uptake of low carbon heating solutions, it is crucial that consumers have a basic understanding of the available technologies and their functionality. This is in addition to the challenge of consumer affordability and access, particularly for vulnerable consumers and those in fuel poverty. Although fuel poverty rates vary across nations of the UK and cannot be directly compared due to differences in the classification methodology, according to latest estimates, 13% of households in England were classed as fuel poor, with 25% in Scotland [113].

2.1.2 Technologies for Low Carbon Heating

There are various technological options for enabling zero emissions heating in buildings, each with their relative merits and limitations. As such, any future scenario will comprise a mixture of available low carbon heating options. At present, the four leading technological solutions are:

- replacing natural gas with hydrogen generated from low carbon electricity;
- using heat pumps;
- using direct electric heating;

- burning sustainable biofuels; and
- use of low carbon district heating (also known as heat networks).

These technologies have varying degrees of maturity, therefore certain technologies dominate uptake projections in the short-term to meet key heat decarbonisation milestones in the net zero transition, whereas others are expected to become more prominent after a period of technological advancement [64], [114]. A brief description of these technological options is provided in the following subsections.

2.1.2.1 Hydrogen

Hydrogen is rapidly emerging as a sustainable solution for decarbonisation of multiple key sectors [115]. At present, it is estimated that 10-27 TWh of hydrogen is produced in the UK each year, mostly for use in the petrochemical sector whereas by 2050, between 250-460 TWh of hydrogen could be needed across the economy, delivering up to a third of final energy consumption [116]. In terms of the decarbonisation of heat, hydrogen has significant potential to reduce carbon emissions although the concept of hydrogen for heating is still largely in its infancy. In principle, hydrogen can be used as a low-carbon alternative to natural gas where hydrogen boilers and other appliances would be used to burn hydrogen instead of natural gas. However, although hydrogen gives zero emissions at the point of use, its value as a low-carbon solution is subject to the production process. There are several methods of producing hydrogen, and these can broadly be categorised into three types as briefly summarised below:

- **Grey Hydrogen**: this form of hydrogen is typically derived from natural gas or methane through a process of steam reformation [117]. The production method is highly CO_2 intensive and is the most common process currently used at scale for manufacturing hydrogen for use in chemicals and fertiliser.
- **Blue Hydrogen**: is produced in a similar manner to grey hydrogen. However, the production process is supplemented with carbon capture and storage (CCS) to capture and store any CO_2 emissions that are produced [117]. The CCS process can be effective in reducing emission levels, though it is not 100% efficient, and emissions would still enter the atmosphere. Additionally, there would also be upstream emissions from sourcing of the fuel necessary for this production technique.

- **Green Hydrogen**: is produced using electrolysis, where water is split into its constituent parts of hydrogen and oxygen by passing electricity through it [117]. Should the electricity be generated from renewable sources the production process would be considered a low carbon sustainable solution.

Distribution of green hydrogen for heating purposes remains the fundamental challenge. However, given the nature of hydrogen, conversion of the existing gas network infrastructure is considered to be a potential solution [116]. This would also require widespread replacement of existing consumer appliances as most currently installed domestic appliances are not 'hydrogen ready' and were not designed to be adaptable. The current UK gas system is highly developed, supplying 85% of buildings via an extensive 270,000 km piped network capable of delivering a peak demand of 3-4 times the peak electricity demand [118]. This demonstrates the scale of the undertaking which would be required whilst simultaneously having to scale up hydrogen markets and manufacturing processes/infrastructure. Therefore, although conversion of the gas grid is likely to be required in the future, most decarbonisation pathways consider that hydrogen will only service a minority of future heating demand via hybrid HP/hydrogen boilers in support of peak winter heating demand in particular areas [53], [115]. As such, hydrogen may be reserved as a fuel for hard to decarbonise sectors that currently rely on the high energy density of hydrocarbons, such as aviation, high grade industrial heat and haulage, with sectors where full electrification is possible, like domestic heat, lower in the priority order.

2.1.2.2 Heat Pumps

HPs are central to almost all decarbonisation pathways in the short- to medium-term as they have the capability to provide low carbon heating, cooling and hot water for residential, commercial and industrial applications [118]. They provide heat for buildings by using thermal energy from an outside heat source and electricity to drive a refrigerant cycle. In general, the heat delivered to the building would be of a magnitude higher than the electricity consumed as heat is transferred from one location to another and not generated. As such, HPs are highly efficient and have an efficiency greater than 100%. With this, the input energy required to meet heat demand would be significantly reduced in comparison with alternative heating options. Additionally, by utilising existing sources of heat available from the surrounding environment, the need to burn fuel is removed along with the associated carbon dioxide emissions. The electricity supply to the HP would also come from low carbon sources, making HPs a highly attractive low carbon heating option.

Broadly, there are 3 primary differing types of HP in terms of heat source:

- air source heat pumps (ASHPs), where heat is absorbed from the air;
- ground source heat pumps (GSHPs), where heat is absorbed from the ground; and
- water source heat pumps (WSHPs), where heat is absorbed from water.

ASHPs and GSHPs are considered to be the most viable options for the majority of households in the UK with WSHPs more suited for bespoke cases where buildings are located near large bodies of water.

Air Source Heat Pumps
ASHPs (also referred to as air-to-water HPs), transfer air from outside of the household into water that can be used to heat rooms via radiators or underfloor heating. There are four primary steps in the ASHP cycle, summarised as follows:

- **Capture**: where a fan passes ambient air over an extremely cold liquid refrigerant, the cold refrigerant begins the cycle in the evaporator. The refrigerant captures the heat energy from the air and becomes a warm vapour.
- **Compress**: the warm vapour is then passed to an electrically driven compressor, increasing the pressure and subsequently the temperature.
- **Exchange**: heat from the vapour is then transferred to the household's heating and hot water cylinder via a heat exchanger.
- **Expand**: once the heat is transferred to the house via the exchanger the refrigerant is passed through an expansion value which decreases the temperature, completing the cycle and returning the refrigerant to the starting state.

Ground Source Heat Pumps
Ground temperature remains relatively constant, even in colder weather, making it a stable heat source. Therefore, GSHPs, (also referred to as ground-to-water HPs), transfer heat from the ground into water that can be used to heat rooms via radiators or underfloor heating. For a GSHP, a mixture of water and antifreeze (also known as 'brine' or thermal transfer fluid)

is pumped around a buried pipe network. This fluid absorbs heat from the ground and then evaporates becoming a low-pressure gas. The low-pressure gas is then compressed and fed to a heat exchanger, transferring the heat to the household's heating and hot water cylinder in a similar manner to the ASHP. The water is then pumped back out to the piped network and the cycle repeats.

ASHPs versus GSHPs

ASHPs are currently the most favoured option for the vast majority of households. In comparison with GSHPs, they are generally easier and quicker to install as there is no need for excavation of land which in general makes them more affordable. At present, the Energy Savings Trust estimates that installation of an ASHP could range from £7,000-£13,000 subject to building characteristics [119]. In comparison, they estimate a GSHP could cost approximately £14,000-£19,000 [119], though stress with installation this could reach as high as £49,000 [120] subject to excavation and system collector design costs (different design options are available for ground heat extraction and application can vary subject to space availability). In both cases, additional installation costs may arise from the need to upgrade the household's existing heat distribution system, building fabric and the necessary electricity supply infrastructure. Note that HPs do not provide hot water on demand and a method of storing water would also be necessary.

As GSHPs require land excavation and considerable planning, the installation time is generally much longer than that of an ASHP. However, GSHPs have the advantage of being hidden underground and as such, garden aesthetics and functionality remain unchanged. That being said, GSHPs require sufficient space to install the necessary ground piping, if only limited space is available a more costly system collector design would be required. They also require sufficient indoor space to fit the relatively large HP unit. In comparison, ASHPs require less space though are visibly protrusive. There are also noise considerations with an ASHP which are exacerbated in colder weather conditions.

Efficiency and Performance

As alluded to previously, HPs can be extremely efficient under the right conditions, such that HPs use between 2 and 4 times less energy than direct heating (via an efficient gas boiler or direct electrical heating) [118]. This is primarily as they produce more heat than the electricity they consume, the amount of heat produced for every unit of electricity used is known as the Coefficient of Performance (COP). The external source temperature drives the efficiency of the HP such that the colder the source, the harder the HP must work to regulate the indoor temperature. Therefore, as the internal and external temperature difference reduces, the COP increases. In practice, the COP is constantly varying with respect to temperature variation. In parallel, increasing building insulation levels and improving material quality will have an overall positive impact on building thermal efficiency thereby reducing heat demand. The extent of this reduction will subsequently have an impact on HP electrical demand and performance. Consequently, the uptake of HPs must be balanced with improvements in building thermal characteristics to ensure sufficient heat retention and to maximise HP efficiency.

Hybrid Heat Pumps

It is recognised that HPs with a standard output temperature installed in existing buildings with current wet based systems and building fabric conditions will be insufficient to meet space heating demand on particularly cold days [121]. This phenomenon is partly illustrated by Figure 2.1 which generalises the behaviour of an ASHP against standard outside air temperatures (note that this does not reflect the temperatures of all regions but temperatures typically observed in the UK). The figure depicts that as outdoor air temperature decreases, the efficiency of the HP also decreases and the heating system temperature increases. The standard heat system temperature limit of a HP is 55°C [118], therefore should the outside air temperature drop to a level that would require the HP heating system temperature to exceed this threshold, the HP in isolation would be insufficient to meet the heating demand requirements.

High temperature HPs and hybrid HPs present as an alternative to extensive insulation and heat distribution system improvements. High temperature HPs with an 80°C threshold limit are typically used for industrial applications and could displace conventional gas boilers on a like for like basis. However, as the outdoor air temperature decreases, the temperature difference between the two sources increases, which reduces the efficiency of the HP. This means the HP needs to work harder to provide the same amount of heat to the indoor space. Therefore, as in Figure 2.1, an increased heating system temperature limit would also yield lower efficiencies and would be significantly more expensive.

Hybrid HPs are an alternative option to conventional HPs where an additional heat source can

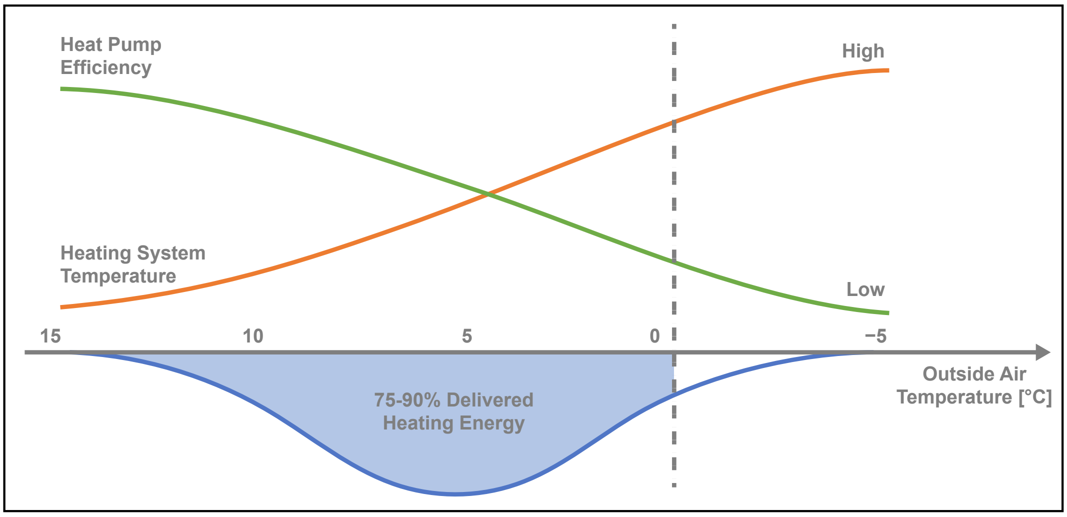


Figure 2.1. General relationship between temperature, heating energy delivered and HP efficiency [122].

be utilised. Typically, the hybrid HP describes fitting a standard HP in combination with a gas or hydrogen boiler. This is a significantly attractive option for difficult to heat households with poor insulation and can provide additional energy security through technology diversity. This set-up would allow for the boiler to be used on occasions when independent HP operation would otherwise be unable to meet the household heat demand requirements e.g. on particularly cold winter days. This could also be beneficial from the network operator's perspective as consumers could be encouraged to make use of this technology diversity to reduce burden on the network during peak times. However, to be fully low carbon, this requires use of hydrogen boilers and hydrogen produced through electrolysis would be coupled to electricity. In addition to the added space requirements, consumers would have to pay for and maintain multiple different heating systems that are technologically unfamiliar.

Summary

In summary, currently in the UK less than 1% of dwellings are supplied by a HP [118]. However, most decarbonisation pathways predict significant uptake of HPs in the transition to net zero which is fuelled by numerous market drivers e.g. support from government incentive schemes such as the Green Homes Grant and Domestic Renewable Heat Incentive Scheme [123], building regulations and energy efficiency improvement schemes and an increasing need to tackle fuel poverty and energy access mandates. The anticipated role of HPs in achieving net zero must not be underestimated, HP markets and supply chains are currently being scaled up to meet UK government targets, specifically the delivery of 600,000 HPs a year by 2028 [39].

2.1.2.3 Direct Electric and Storage Heaters

Direct electric heaters and storage heaters are generally the most common type of electric heating currently installed across the UK. They are typically found in off-gas locations, in flats and in rented properties. Direct electric heaters generate heat instantly at time-of-use whereas storage heaters enable households to capitalise on the lower cost of electricity during the night to charge the heating system and then release the stored heat during the day when electricity costs are typically higher i.e. on an Economy 7 tariff [124]. Direct electric heaters such as panel heaters and wall-mounted electric radiators are often used in a supplementary capacity as a secondary heating option and can be expensive to operate though provide the advantage of being able to heat a single room for a short period of time.

In 2015, Ofgem analysed the experience of consumers with electric heating and the relative demographics [125]. They identified that in GB, 25% of flats use electric heating (excluding HPs) compared to only 4% of houses and that dwellings with electric heating systems tended to have a lower energy efficiency rating, contributing to the higher costs associated with running electric heating [125]. Also identifying that these households tended to have a lower income and thus combined with higher heating costs be ‘fuel poor’. As such, although households that are currently heated by electricity are of lower priority to retrofit – as they already have low emissions at point of use – in many cases the motivation exists to change or upgrade heating systems due to energy poverty concerns.

An advantage of direct electric heating and/or use of electric storage heaters (ESHs) is that they are likely to have a lower upfront cost in comparison with an electric alternative such as installing a HP, where the initial capital cost and property feasibility could be prohibitive (high-rise flats may not be suited for HP installation). Additionally, modern electric heating technologies, in particular storage heaters, have significantly improved in the last several decades and since the Ofgem study in 2015 e.g. storage heaters manufactured after 2018 must adhere to stricter efficiency standards and tend to have higher heat retention and improved control functionality which can reduce running costs [126]. As such, in many cases depending on the demographic, heating requirements, dwelling size and insulation properties it may be more cost effective in the interim to upgrade to a modern electric storage heating system with enhanced controllability than switching to an alternative technology.

In this regard, direct electric/storage heaters present as a potential low carbon heating solution for future use in the transition to net zero under specific circumstances. However, fuel poverty concerns and policy related challenges associated with existing use of these technologies raise a number of concerns for ubiquitous use at scale. Furthermore, there is less emphasis and priority placed on the switching of electric heating technology e.g. storage heaters to HPs from a decarbonisation perspective than in comparison with switching from use of gas and gas fired boilers to low carbon alternatives.

2.1.2.4 Sustainable Bioenergy

Bioenergy includes all types of fuel produced by living organisms, whether solid, liquid or gas e.g. biogas/biomethane, bioliquids and solid biomass [50]. It is recognised that bioenergy can support decarbonisation in 'difficult-to-treat' properties typically located in rural areas that are unconnected to the gas grid.

Biogas/Biomethane

Biogas (often referred to as renewable natural gas) is typically produced via anaerobic digestion which utilises plant and animal waste [50]. This is generally upgraded to biomethane which can be used in the same manner as natural gas. Biomethane can also be blended or injected into the existing gas grid supporting cost-effective short-term decarbonisation. However, as biomethane is fundamentally derived from waste, resources are scarce which reduces its ability to contribute to heat decarbonisation in any substantial capacity, at most this could only meet approximately 3-10% of 2019 UK gas demand [118].

Solid Biomass

From an energy and heating perspective, the most common biomass materials include plants, wood and waste. When managed and harvested in a sustainable manner, biomass can reduce emissions for heating by directly displacing oil, coal and natural gas use. However, if unmanaged, there is a risk that biomass production could be worse for the climate than burning fossil fuels [127]. Biomass heating systems in the UK predominantly burn wood pellets, chips or logs to provide heat, this is highly inefficient particularly on open fires and aged wood-burning stoves both in terms of energy production and on an air quality basis [118]. Smoke particulates and oxides of nitrogen are released when biomass is burned in this manner, as such the CCC have recommended that biomass for heat should not be used in urban areas [127]. Though they have identified that biomass boilers perform better and that there is scope for use in niche low density rural areas where pollutants are more easily dispersed. Also, indicating that potential future heat demand is likely to exceed sustainable supply of biomass severely limiting its value as a ubiquitous decarbonisation option. The CCC have recommended that government policies should assist a transition away from the use of biomass for heating residential buildings and that biomass should only be used in niche applications. Recommending to BEIS that support should end for biomass boilers where there are alternative low carbon heating options [127].

To summarise, the CCC have encouraged the use of alternative low carbon heating options instead of bioenergy for heat in buildings, limiting its use to: biomethane produced by anaerobic digestion, integration with hybrid HPs for use in hard-to-treat off-gas-grid properties and for use in local Combined Heat and Power (CHP) systems and small-scale district heat networks [50]. As such, although bioenergy will have a role to play in the ongoing transition, on the scales concerned with the decarbonisation of heat there are significant limitations to universal adoption.

2.1.2.5 District Heating/Heat Networks

District heating or heat networks is a distribution system comprised of an insulated pipe network that circulates hot water to transfer heat from a central fuel source to end consumers. Provided that the central source is low carbon in nature the heat network would be considered a low carbon heating option. In the UK, there are currently over 14,000 heat networks providing both heat and hot water to approximately 480,000 consumers which equates to approximately 2% of UK heat demand [128]. The CCC have estimated that this could rise to 18% by 2050 with sufficient government support [128]. It is estimated that 50% of existing heat networks in the UK are not inherently low carbon and are powered by gas. As such, decarbonisation of existing networks is considered to be a priority, though unlike the use of ubiquitous gas boilers, the principle of switching from a centralised fossil-fuelled source to a low carbon alternative is far simpler. There are a plethora of low-carbon heat sources that can be used such as: waste heat (industrial processes, data centres, underground transport and sewage), low-carbon fuels (large biomass boilers, hydrogen boilers/fuel cells, industrial sized HPs and solar energy), and CHP systems [39]. This technological diversity provides an additional layer of energy security and can introduce competition into the supply chain. The scale and complexity of these networks can vary significantly, for example, they can be used to supply single, multi-occupant buildings such as a block of residential flats or at a larger scale where consumers are distributed, and multiple dispersed heat sources are required [39]. This makes heat networks a highly attractive and cost-effective heating option for densely populated areas. Heat networks are extremely common in Scandinavian countries, e.g. in Sweden over 50% of households are supplied via heat networks [39].

Like the gas network, as heat networks are more suited to areas with higher population densities, they are less practical for full coverage in a rural setting. However, heat networks are still an attractive option for many rural communities e.g. a heat network could supply the bulk of heat demand in a rural village population centre with surrounding properties disproportionately located from the centre such that heat network connection would become economically impractical decarbonised via an alternative solution. Heat networks have the added benefit of central management that can balance the supply and generation of heat, both spatially and temporally. This allows for centralised optimisation of plant with respect to heating demand requirements (and potentially other local assets in a local energy system scenario) e.g. shifting use between, residential, commercial and industrial properties relative to consumer behavioural trends. The aggregation of potentially many diverse individual properties' heat demands to large single centralised sources would also then allow for seasonal demand forecasting and management.

With respect to the electricity network, the impact of heat networks largely depends on the heat source and the functionality. A single large industrial sized heat source used to supply many properties would not have the same property to property impact on the LV network as with HPs for example. However, depending where the heat network was connected – most likely at HV depending on size – this would have a larger impact on a specific area of the network. As such, the extent of network impact would vary significantly relative to the plant size and install location. Similarly, a multi-source heat network would have an entirely different impact on the network. A heat network with multiple heat sources connected to the electricity network could lead to decentralised management of each plant to optimally manage network capacity and resource availability.

A significant challenge with heat networks is that investment is limited by high upfront capital costs (excavation and installation) and long payback periods. In the case of retrofit heat networks, there is also uncertainty surrounding the costs and requirements of property connection costs as outlined in [128]. Add to that ownership and responsibility for operation and management of the network, as unlike conventional heating systems, heat networks are largely unregulated in the UK. This raises concerns surrounding responsibility for maintenance, maintenance costs and quality of service. Additionally, whilst consumers can change heating systems, or upgrade their systems, with heat networks consumers are also unable to switch providers and as such, are often at the mercy of a local unregulated monopoly.

2.1.3 Summary

This section describes and emphasises the considerable challenges associated with the decarbonisation of heat. The various low carbon heating options available to support decarbonisation discussed in this section are all considered to be viable alternative heating solutions. However, they are not without their limitations and any future scenario is likely to comprise a mixture of the solutions presented. In addition, irrespective of the adopted solutions, building efficiency measures and changes in consumer behaviour remain necessary though the extent of which may vary subject to individual technological requirements. From the discussion: hydrogen, district heating and HPs present as the most viable solutions for heat decarbonisation at scale. However, hydrogen distribution via the gas network, district heating and GSHPs specifically all have significant upfront installation/upgrade costs and lead times. This tends to make ASHPs the most favourable solution in terms of practicality and affordability for short- to medium-term heat decarbonisation at scale, despite the related limitations discussed.

In terms of the power system and electrical network infrastructure, each of the solutions described will have their own unique impact e.g. electrolysis is likely to require significant investment in transmission connected renewable energy and infrastructure to meet the demand for hydrogen, whereas ASHPs and district heating are likely to require extensive distribution network reinforcement (in absence of alternative network solutions). Ultimately, there will be an increased demand for electricity and dependency on the electricity supply chain.

2.2 Decarbonisation of Domestic Transport

As also identified in the previous chapter, the decarbonisation of domestic transport is instrumental to achieving net zero. In this section, the decarbonisation of domestic surface transport is considered, focusing specifically on rail, bus and cars. It is recognised that decarbonisation of aviation and shipping will also be necessary. However, this is considered to be outside the remit of this work. Additionally, there are parallels to the decarbonisation of transport in other sectors e.g. vehicles and mobile heavy machinery in both the agricultural and construction industries that are not considered.

There are typically two approaches to the overarching decarbonisation of transport which are summarised as follows:

- **Demand-based solutions:** where focus is placed on changing consumer behaviour and travel habits. This includes encouraging a ‘modal shift’ away from car use, increased active travel and a ubiquitous reduction in transport demand.
- **Technology-based solutions:** where focus is placed on meeting transport demand via technologies that are net zero compatible. This includes use of technologies supplied from low carbon sources e.g. electricity or hydrogen.

It is recognised that whilst both approaches are of value, a combination of both demand- and technology-based solutions are necessary to achieve the required reduction in transport emissions [118]. Both approaches are described in detail within this section.

2.2.1 Demand Reduction and Modal Shift

The department for transport have emphasised that transport demand is expected to substantially increase in the coming decades [118]. With this, there is a recognition that technology-based solutions in isolation will not be sufficient to meet this demand growth. As such, there is a growing requirement to adopt demand-based solutions in parallel that seek to change consumer behaviour and travel habits. A modal shift away from private car usage is considered to be a highly attractive option to support the decarbonisation of transport. This in part would involve promoting and providing alternative means of travel to private cars e.g. use of public transport infrastructure. There are different mechanisms available to influence such behavioural changes. For example, stop-gap measures such as Glasgow's Low Emission Zones [129] and London's Ultra Low Emission Zones [130] have been deployed to deter private car use in urban environments whereas long-term solutions could see strategic urban design and planning that prevents the use of private vehicles entirely. It has been recognised that there are wider societal benefits to such developments [118]. Modal shifting in this manner would require that public transport infrastructure is low-carbon and fit for purpose. Additionally, as expensive public transport may act as a deterrent for consumers, low-carbon infrastructure should be affordable and reliable to encourage use.

Alternative design and planning of residential estate areas through '20-minute neighbourhoods' that localise services to reduce travel time is considered a favourable option [131]. This would help to promote and facilitate more active methods of travel such as walking and cycling whilst helping to tackle wider societal health issues in the UK. Shared vehicles and 'car clubs' [132] are additional methods of reducing car ownerships and traffic congestion.

2.2.2 Technologies for Low Carbon Transport

Whilst demand-based solutions are likely to support the transition to net zero, it is acknowledged that technology-based solutions are expected to reduce the bulk of transport related emissions. The key technological options available to enable low carbon rail, bus and car transportation are described in this section.

2.2.2.1 Cars

As identified in Section 1.1.1, private cars with internal combustion engines are the largest contributors to total domestic transport emissions in the UK. The decarbonisation of these vehicles requires a technological shift to ULEVs which emit significantly less emissions in comparison. Under the umbrella of ULEVs there are various technological options that are available to support decarbonisation. These are generally supplied, as with buses and trains, by either electricity or hydrogen and in unique cases synthetic fuels. The most prominent technological options currently available are classified as follows [133]:

- **Battery Electric Vehicle (BEV)**: these vehicles are solely powered by electricity where an internal battery (typically lithium-ion) is charged by an external power source.

- **Plug-in Hybrid EV (PHEV)**: these vehicles combine a chargeable battery, electric drive motor and an internal combustion engine. They have the option of using the combustion engine, electric drive motor or a combination to power the vehicle.
- **Hydrogen Fuel Cell EV (FCEV)**: these vehicles are powered by electricity generated from a chemical reaction between hydrogen and oxygen in a fuel cell stack.

As only BEVs and FCEVs have zero tailpipe emissions under all driving scenarios, this work exclusively describes these two types of vehicles further.

Battery Electric Vehicles

The uptake of BEVs will significantly increase the demand for electricity across the UK and thus challenge the existing electricity system and its infrastructure. BEVs are generally considered to be the primary technological option to facilitate the decarbonisation of private vehicles in the transition to net zero. At the end of March 2022, there were 833,000 licensed ULEVs in the UK, 58% of these where BEVs (483,140) [134] and according to NGESO's FES 2022 approximately 37 million are anticipated by 2050 [64]. Although BEVs have zero tailpipe emissions, their decarbonisation value is reliant on the carbon intensity of the electricity generation source of their supply. In a renewable dominant power system this would ensure that BEVs are a viable low carbon alternative to ICEVs. BEVs are also comparably more efficient and can significantly reduce noise pollution in comparison with ICEVs. BEV life-cycle emissions are generally 50-70% lower than that of ICEVs [118].

BEVs present an alternative challenge that stems from their inherent nature, that is the vehicle's mobility. With the appropriate charging infrastructure and conditions, BEVs can be charged at a number of different locations including at home, work and a number of public locations such as charging stations and supermarkets. In [105], these are categorised into four archetypes: domestic, workplace, public and en-route. This makes it challenging for DNOs to predict the electricity demand in different locations as consumer travel behaviour varies. A further challenge with the uptake of BEVs, is the locational constraints on the charging infrastructure i.e. specific locations may not be equipped to accommodate installation. This may deter consumers from adopting BEVs and could also influence charging behaviour e.g. consumers who do not have access to off-street parking would be forced to charge at different locations potentially altering their current travel behaviour. This is in addition to the BEV driving range concerns currently manifested within the public domain i.e. driving range is limited by the battery capacity (typically ranging from 30-100 kWh), therefore for 'long' distance journeys a stop en-route to re-charge may be necessary. This would be longer than stopping to refuel an ICEV, extending the total journey time. Charge time would vary subject to BEV battery capacity, state of charge and charger/BEV type. For example, rapid and ultra-rapid chargers (43, 50 and 100+ kW) can charge an EV to 80% in 20-60 minutes whereas fast chargers typically 7 kW and 22 kW can take 4-6 hours or 1-2 hours, respectively. A slow charger (3 kW) can take 6-12 hours [135]. As such, ultra-rapid and rapid chargers are generally used for en-route and some public charging due to the time sensitivities and consumer inconvenience e.g. motorway service stations and charging hubs whereas fast and slow chargers are used for workplace and domestic locations which are less time constrained and more convenient for consumers.

Although interest surrounding BEVs has increased significantly in recent years, their uptake is still contained to the innovators and early adopters on a typical technology adoption curve. This is partly due to the high upfront costs associated with BEVs in comparison with ICEVs. There is also the added cost of installing a home or workplace charger that generally accompanies purchase of a BEV. However, there are now also over 30,000 public charge points installed across the UK enabling more active charging whilst travelling [136]. The capabilities of BEVs also extend beyond decarbonisation and reduced noise pollution which further adds to their value as an alternative solution to ICEVs. There is significant potential for 'smart' controlled charging to provide both grid management services and local consumer benefits e.g. charging of BEVs that is scheduled with respect to electricity price or grid carbon intensity (this would allow for maximisation of the renewable energy potential) [137]. 'Smart' charging also allows for the use of V2G which has been described in a number of works [138], [139]. V2G is bi-directional charging and discharging between the grid and the EV. This would allow consumers to become prosumers that can monetise their available capacity via a local market arrangement. Here the principle of smart charging and V2G flexibility is briefly touched upon. However, the full flexibility potential is further explored within the dedicated flexibility section (Section 2.4).

Hydrogen Fuel Cell Electric Vehicle

FCEVs are a renewable alternative to BEVs and unlike other ULEVs, their range, refuelling processes and times are comparable to conventional ICEVs [133]. Unlike BEVs, FCEVs also have long term life-cycle sustainability and dependency advantages. However, to enable mass uptake of FCEVs significant technological advancement and extensive hydrogen charging infrastructure would be necessary which currently does not align with net zero timescales. At present, there are less than 20 public hydrogen refuelling stations across the UK and only 2-3 vehicle models which are considerably more expensive than many BEV models, reiterating the challenge with FCEVs [118], [133]. FCEVs are also less efficient than BEVs as they rely on a conversion process whereas BEVs are solely reliant on electricity which carries minimal losses. The challenges with hydrogen infrastructure for heating have previously been discussed and similarities extend to the use of FCEVs. Beyond 2050 FCEVs may become a more ubiquitous technology with technological advancement and infrastructure development.

2.2.2.2 Rail and Bus

Low carbon trains and buses are instrumental to achieving transport decarbonisation targets. This is compounded by the growing motivation to increase public transport usage in support of a modal shift from private vehicle use. In terms of trains and the rail infrastructure, electric trains are already extensively used across the UK, particularly in Scotland [140]. However, a need still exists to displace conventional diesel trains to meet net zero targets. In Scotland, all remaining diesel trains are to be removed from the network by 2035 [140]. The most viable alternatives to electric trains include hydrogen or battery trains. These technologies have the potential to support decarbonisation of the rail network in areas where electrification is considered to be impractical or financially unviable. However, in the case of hydrogen trains, the necessary storage capabilities and supply infrastructure would be required in suitable locations. For example, hydrogen trains may present as a potential cost-effective solution in remote areas near offshore hydrogen production facilities where train timetables would be less frequent and cover larger distances.

Similarly, electric buses or hydrogen buses are considered to be the key technologies supporting the decarbonisation of conventional diesel buses. These buses also tend to be quieter than conventional buses and therefore have the capability to reduce noise pollution. Additionally, with fixed timetabling of routes and scheduled stops, buses are far more predictable than private vehicles which should enable a more robust transition in terms of infrastructure sizing and capacity utilisation. Additionally, as fleets of buses will have dedicated charging terminals, the necessary electricity charging infrastructure or hydrogen refuelling capabilities would be centralised. This in turn would allow for appropriate upgrade planning of the surrounding distribution network infrastructure (as necessary).

2.2.3 Summary

This section describes the relative challenges with the decarbonisation of domestic transport and the mechanisms by which this can be achieved with respect to the net zero timeframe. The approaches available to support this transition are described where it is identified that both demand- and technology-based solutions are required. Demand-based solutions are inherently socio-economic and aim to encourage and facilitate a modal shift away from private vehicle use in favour of alternative means of travel e.g. use of public renewable transport and more active alternatives such as walking and cycling. Technology-based solutions would see a shift from private ICEVs to ULEVs, predominately BEVs (referred from here on as EVs) given the current challenges with FCEVs.

In any future scenario, a diverse mixture of both demand- and technology-based solutions will be necessary to meet net zero targets. However, the available options, in particular EVs, are expected to have significant impact on the electricity system and the existing infrastructure due to their charging requirements. Demand-based solutions which inform travel behaviour are expected to influence demand in different locations (characterised as socio-technical and socio-spatial influences) where the extent is expected to vary subject to the relative decarbonisation pathways of individual areas.

2.3 Distribution Networks

In this section, distribution networks in GB are described in an extended level of detail. This includes a description of the general design and topology, the relevant assets, and their configuration.

2.3.1 Design and Topology

Distribution networks span multiple voltage tiers across various geographical areas comprised of diverse population types. As such, distribution network design varies significantly across different areas e.g. rural and urban environments. Distribution network design therefore must balance cost with consumer requirements such that the network is not over designed, requiring high capital expenditure for underutilised assets or under designed which may impact consumer quality of service. There are a number of additional factors that will impact network design including: environmental considerations, existing network planning practices, the available/favoured assets and the relevant standards at the time of installation.

In practice, specific areas will have their own unique design and planning considerations. However, DNOs tend to use generic planning approaches and a standardised asset base from the outset to ensure continuity and that relevant standards/codes are met. This also ensures that spare part inventories and staff training will be sufficient for across the entire network. Fundamentally, power system assets such as transformers have significantly long-life cycles and therefore many legacy assets and practices exist which will influence future development and design decision making. The following summarises the generalised design of each distribution network voltage tier.

2.3.1.1 EHV Distribution System

EHV networks are supplied from transmission networks via GSP transformers (typically 275-132/33 kV). The EHV network is comprised of a group of circuits that provide supplies to primary substations and to consumers with an EHV supply point (typically large industrial demands). The GSP transformers are generally of a star-delta connection where the star point of each primary winding is directly earthed. Each transformer is typically connected via 33 kV circuit breakers. The transformers are equipped with an on-load tap changer (OLTC) to aid voltage management and an Automatic Voltage Control (AVC) scheme which is configured to maintain the secondary voltage within ±2% of the nominal voltage [141]. The transformers are heavily protected in comparison to other network assets, this generally consists of at least 2-3 layers of protection including overcurrent and unit type protection.

Urban EHV circuits generally consist of two transformer feeders operating in parallel, controlled by two 33 kV circuit breakers. They tend to allow interconnection between different GSPs via a normally open point. Rural EHV networks are similar to urban networks in terms of automation and protection. However, they are generally supplied via three-phase overhead lines without an earth conductor in comparison with underground cabling in an urban setting. The 33 kV circuit breakers are generally fitted with auto-reclose equipment (at least more recent installations) to allow for automated clearing of transient faults.

2.3.1.2 HV Distribution System

HV networks are supplied from EHV networks at primary substations via primary transformers (typically 33/11-6.6 kV). The HV network is comprised of a group of circuits that provide supplies to secondary substations and to consumers with a HV supply point [141], [142]. These circuits are generally interconnected between primary substations via normally or soft open points. HV networks are comprised of both overhead lines and underground cabling, the extent of which varies subject to the geographical location of consumers and demand centres e.g. the HV network supplying rural areas in the north of Scotland would have significantly more overhead lines than in and around urban areas.

The primary transformers are generally delta-star connected and earthed at the secondary winding. Often there are twin connected transformers for N-1 security conditions, although single primary transformers are still present in certain areas. These transformers (those more recently installed) are generally fitted with OLTCs for voltage management. As with GSP transformers, primary transformers are also controlled by AVC relays which are configured to maintain the secondary voltage within ±2% of the set point voltage under all load conditions. They are generally set to target 11.2 kV at the HV busbar of the primary substation in account of the voltage drop to the secondaries. Where additional consideration of HV voltage drop is required, line drop compensation is often used, particularly when supplying rural networks via overhead lines.

HV networks in urban and rural areas can differ significantly in terms of their configuration and topology. Urban HV networks are typically in the form of a ring main fed from two separate sections of a double busbar at the primary substation. Urban HV circuits are generally controlled by a ground mounted circuit breaker and may loop in secondary ground mounted substations to the ring at various points along its length [141]. They are predominately comprised of underground cabling. For HV rural networks, these are predominantly comprised of overhead lines (cabling is often used in the presence of ground mounted transformers) constructed and designed as a series of three-phase main lines with radial spurs lines branched off as demonstrated in Figure 2.2. In practice, Figure 2.2 would also typically contain a ground mounted transformer and underground cabling e.g. Figure 2.2 would represent supply to farms

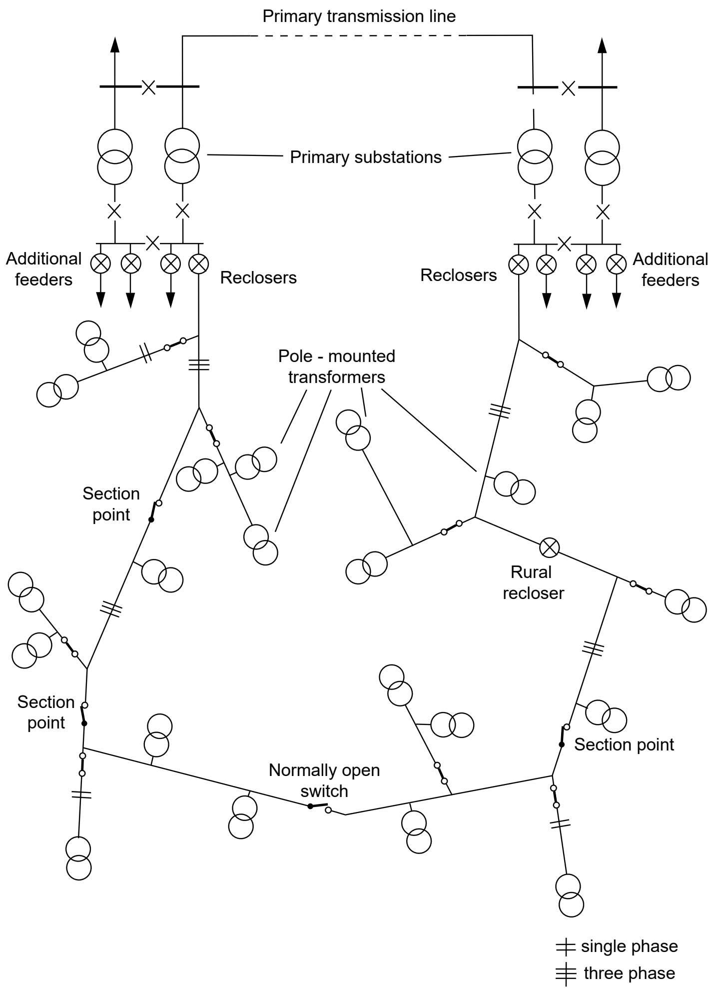


Figure 2.2. Example of generic HV rural network design topology [57].

and isolated properties on the outskirts of a rural village where a ground mounted transformer would be installed to supply the bulk of the demand. As these rural demand centres are sparsely located, overhead lines must span significant distances and challenging terrains, as such they are particularly susceptible to extreme weather conditions and security of supply is often challenged as a result. Auto reclosers are used to distinguish between fault events and minor perturbations which can be automatically cleared without onsite manual intervention e.g. a tree branch falling on an overhead line. Historically, fuses have been used to protect pole mounted transformers commonly found in this setting. However, automatic sectionalisers have replaced these more recently allowing for distinction between transient and persistent faults.

2.3.1.3 LV Distribution System

LV networks are supplied from the HV network at secondary substations via secondary transformers or distribution transformers (typically 11-6.6/0.4 kV). These are generally either pole mounted transformers supplying few consumers or ground mounted supplying a higher concentration of demand. A delta-star arrangement where the neutral point of the secondary winding is directly earthed is a common setup for ground mounted transformers [141]. They are also typically off-load tap changing transformers (manual intervention is required to change tap settings) where the secondary voltage can be varied to minimise voltage drop [141], [142]. In GB, at consumer supply terminals the voltage must be maintained within +10%, -6% of 230 V (phase-neutral), in the EU this is set at ±10% [143], [144].

Fuses are installed on all LV feeders as a means of overcurrent protection. In general, the LV network conforms to a standard radial design with no interconnection. However, any portion of the LV network that is interconnected is operated as radial and configured as open ring [142]. LV networks are generally supplied via underground cabling although overhead lines are often present in rural settings. Underground LV network cabling is typically installed under footways; therefore any upgrades or reinforcement would require excavation and cause significant disruption. Where applicable, link boxes are used as a means of isolating sections of network in the event of a network fault or planned works to maintain supply to the consumers. Furthermore, LV networks have traditionally been designed to balance consumer loading across the three-phases. However, this is a trying task and in rural networks in particular, significant unbalance is present.

2.3.2 The Evolution of Distribution Networks and Their Operators

The following sections provide a brief contextual overview of the evolution from passive to active distribution networks, the challenges with decentralisation and the uptake of DG, and the evolution from DNOs to DSOs. The impact that the decarbonisation of heat and transport has in this regard is also considered.

2.3.2.1 Passive versus Active Distribution Networks

Historically, distribution networks played a passive role in the power system, primarily connecting the bulk of demand to the electricity network. Due to the relatively predictable nature of demand, in particular domestic demand e.g. seasonal variations in evening peaks and early-morning troughs, DNOs tended to operate under a 'fit and forget' policy of asset installation [77]. As previously alluded to, this typically involved using relatively simplistic approaches to network planning and asset sizing due to the low risk associated with demand uncertainty. Assets were often oversized as it was more cost effective to ensure sufficient capacity and headroom than to replace assets periodically which would be costly and highly inconvenient to the consumer. With this approach to network planning and management, unlike at the transmission network where greater priority and risk were placed, there was a lack of technical need for automated control and monitoring of assets and power flows in the distribution network, particularly at LV [68]. This meant that DNOs operated and managed these networks based on a highly limited measurement set [68], [78], taking a reactive approach to asset management and network reinforcement.

In contrast, as future distribution networks become increasingly decentralised, significantly more active, and are expected to see extensive penetrations of variable DG, distributed energy resources (DERs) and LCTs at both HV and LV [67]. Both the distribution networks and the DNOs are having to evolve and adapt to ensure that they are equipped to manage the changing behaviours stemming from these expansions. With these evolutions and the technological advancements in communications, monitoring and control, the concept of active distribution networks or 'smart grids' has been the focus of discussion for a number of years [145]–[148]. In that a more active approach to managing and operating distribution networks can be achieved by developing 'smart' management systems and infrastructure [146]. Enabling enhanced utilisation of assets within the network e.g. operating assets closer to their respective limits. In recent years, machine learning, artificial intelligence and 'big data' have formed part of the discussion with enhanced asset monitoring techniques being proposed in the literature [149]. In an active network environment, the need for monitoring extends beyond asset maintenance with an increasing requirement for visibility of power flows and voltages across all voltage tiers of the distribution networks. However, such monitoring, communications and data management infrastructures have significant capital expenditure and can exacerbate cyber security concerns. Therefore, optimal placement of monitoring devices within the network to maximise visibility at least cost has also received recent attention [150], [151].

In GB, the rollout of 'smart' meters is set to provide every household with a means of monitoring their energy usage to encourage more energy efficient behaviour and allow for accurate automated billing [152], [153]. As of September 2022, an estimated 30.3 million ‘smart’ meters have been installed in GB [154]. From the perspective of DNOs, such installations could yield greater insight into consumer demand and therefore feed into planning and management decision making within an active environment. This would also support detailed time-coupled demand and network modelling research. However, due to data privacy concerns, DNOs do not currently have access to this data at sufficient granularities. There are also concerns with technology robustness and consumer acceptance that have been identified by the roll-out thus far [153]. An additional caveat from the network perspective is that current ‘smart’ meters are typically only intended to monitor active power consumption of a single connection, therefore it would be difficult to distinguish between demand from multiple energy vectors (unless these are otherwise monitored) e.g. an EV or HP and conventional household demand.

As highlighted in [68], due to a lack of need at the time and a desire for expedited connection of DG, the vast majority of generation in GB currently connected to the distribution network is unobservable, as such, exact quantities of installed DG are largely unknown. This is particularly applicable for sub 1 MW connected generation. Indicating that as distribution networks transition from passive to active, a requirement may exist for costly retroactive installation of monitoring equipment for these assets in key areas of the network. The importance of this is emphasised with respect to the uptake of DERs and LCTs associated with the electrification of heat and transport, in that although there is a substantial desire to meet decarbonisation targets through uptake of these assets, functionality and broader long-term network impacts must be considered as distribution networks continue to evolve. To reduce the level of uncertainty exacerbated by LCTs, better foresight of how networks may evolve and the role of these assets within such networks is required.

Fundamentally, active distribution networks require increased network visibility and control through advanced communications, monitoring and data management/utilisation. Such advancements are necessary if DNOs are to evolve into DSOs that are capable of efficiently and cost effectively managing and operating future distribution networks, and to fully utilise emerging flexible management practices.

2.3.2.2 Decentralisation and Distributed Generation

It is recognised that with the motivation to decarbonise energy systems and the cost reduction of renewable energy technologies the power system is becoming increasingly decentralised as the share of electricity produced at distribution level increases [68]. The continued uptake of DG presents several challenges to power system planning, operation and control, impacting both the system operator and DNO in a variety of different ways. Therefore, in terms of this thesis although DG is not the explicit focus of this research, it would be remiss not to briefly consider its wider role in the evolution of the distribution network and the impact it will have on future operating practices.

In GB, certain areas have already achieved high penetrations of variable DG. These connections have typically been installed under a 'fit and forget' policy with the assumption of a strong transmission system [68]. As such, technical requirements for DG connections were initially underdeveloped which has led to a significant lack of visibility and control. It is identified in [68] that DG comprised 35% of the total installed generation capacity in GB for 2019, where 59% was asynchronous with a renewable energy source and 41% synchronous with a storable fuel source (noting that the bulk of synchronous connected DG lacks the plant level and network level controls to be utilised for system operation). The installed capacity connected to the transmission and distribution networks for the period 2013 to 2020 inclusive is shown in Figure 2.3.

The figure highlights that the share of asynchronous generation connected to both the transmission and distribution networks has increased substantially in the period shown. On the transmission network, the bulk of this can be attributed to onshore and offshore wind connections. For the distribution network, this can be attributed predominantly to onshore wind, solar photovoltaics (PV), and biomass/CHP. The bulk of onshore wind is connected at 11 kV and above, whereas the bulk of solar is connected at LV.

As the vast majority of DG connected in GB is uncontrollable, unobservable (from the system operator's perspective) and driven by weather dependent sources, the true system demand as seen at the GSP is becoming increasingly harder to forecast which has the potential to impact NGESO's ability to manage energy imbalance close to real time [68]. There is also an increasing need for improved voltage management and control at this interface as traditional methods

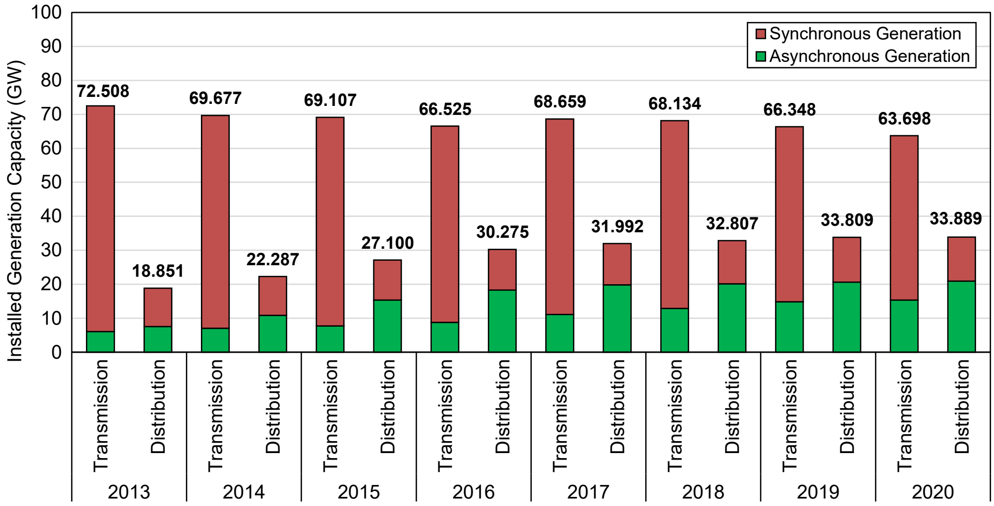


Figure 2.3. Installed generation capacity for synchronous and asynchronous generation connected to the transmission and distribution networks in GB [68].

of voltage control reliant on transmission connected synchronous generation become less effective. In the distribution network, DG is altering power flows and demand profiles across the network and has introduced a variable flow of power in certain areas of the network (in terms of direction) which challenges conventional network management and planning practices. Several other prominent DG related challenges are briefly summarised as follows:

Unintended operation of DG protection: DG is connected with Loss of Mains (LoM) protection which is designed to disconnect the DG and prevent unintentional islanding during a disturbance. Historical LoM protection settings are overly sensitive for a low inertia system and can undesirably disconnect DG from the system in response to faults on the transmission network, even when the original fault is cleared contributing further to the power imbalance and exacerbating the effects of the original disturbance. A programme [155] is in place to upgrade these settings to prevent undesirable tripping of DG. However, until this is fully completed the threat of unintended disconnection remains.

Low Frequency Demand Disconnection (LFDD): during extreme contingencies, the system frequency may fall outside of operational limits. Therefore, in GB, to prevent reaching underfrequency protection limits of generating equipment and collapse of system frequency, the LFDD scheme is in place to automatically disconnect portions of demand such that the system frequency can be restored to within operational limits [68]. As DG penetration increases, the effectiveness of the LFDD scheme is challenged and its level of success becomes dependent on the demand and generation mix downstream of each relay at the time of operation (as both demand and DG would be simultaneously disconnected in the event of LFDD activation). Note that in a future scenario this would include any electrified heat or transport demand potentially leaving consumers unable to travel or heat their homes thus intensifying the impact of LFDD activation and consumer dependency on the electricity network. Without visibility of DG (and LV-connected LCTs), uncertainty is introduced into the amount of true demand on the system at any given time and, therefore, the net effect of LFDD on system frequency when activated is uncertain. In [156], the relationship between DG and LFDD is investigated further by testing the effectiveness of readily available solutions which show potential improvements relative to the present-day scheme.

Effects of DG on Short Circuit Level (SCL): the significantly high penetrations of DG already connected to the network have caused an increasing trend of SCL[7] at lower distribution voltages. It is recognised that the main challenge with increasing SCL is limiting the maximum fault current to within the rating of surrounding network switchgear. It becomes a significant health and safety concern should the switchgear rating be exceeded and may also lead to network security challenges. Consequently, switchgear upgrade costs often have to be factored into DG connection costs which may act as a deterrent for new connections.

As identified, DG and decentralisation in general, brings significant challenges to conventional network operation. However, there are considerable benefits which include: increased renewable generation, diversification of renewable technologies, opportunities for local businesses and reduced end-to-end losses as DG is generally located in closer proximity to demand. The decarbonisation of residential heating and transport is set to add further uncertainty and complexity, to several of the challenges described above.

2.3.2.3 Distribution Network Operators versus Distribution System Operators

As networks become increasingly decentralised and more active the fundamental roles and responsibilities of a conventional DNO have been brought under scrutiny and concerns have been raised with whether they are fit for purpose in an active decentralised low carbon landscape.

[7] The short circuit level at any given point in the power system is the amount of current that would flow if there was a short circuit fault at that point.

The concept of DSOs has therefore formed a large part of the debate in the ongoing transition to net zero. There are generally conflicting definitions and opinions on what would constitute a DSO, one definition being:

> *"A DSO securely operates and develops an active distribution system comprising networks, demand, generation and other flexible DERs. As a neutral facilitator of an open and accessible market it will enable competitive access to markets and the optimal use of DER on distribution networks to deliver security, sustainability and affordability in the support of whole system optimisation. A DSO enables customers to be both producers and consumers, enabling customer access to networks and markets, customer choice and great customer service"* [157].

In a similar vein, distribution system operation implementation plans, defined as, *"a set of functions and services that need to happen to run a smart electricity distribution network. This does not focus on a single party as an operator but recognises roles for a range of parties to deliver distribution system operation."* have been developed in parallel with DSO road maps to bring together the many different stakeholders [158]. In May 2023, UKPN launched GB's first independent DSO which *"will ensure that sufficient electricity capacity exists across London, the East and South East to support the anticipated uptake of EVs, heat pumps and renewables generation."* also *"to incentivise customers to shift their energy consumption or generation, to maximise use of its existing electricity grid infrastructure and facilitate the lowest cost transition for customers adopting low carbon technologies."* [159]. Nevertheless, until the various DSO road maps and implementation plans are fully realised (if they ever materialise in practice), DNO planning tools and capabilities will still be required, particularly in the next decade. Therefore, the remainder of this thesis continues to use DNO rather than DSO.

2.4 Flexibility in the Electricity System

The need for and potential value of flexibility in the electricity system has previously been established therefore in this section, flexibility as a concept in the context of the decarbonisation of heat and transport is further explored. Whilst the focus is primarily on the electricity system, flexibility does extend beyond this to the interactions between different energy vectors and 'the whole energy system', and into the ecosystems of society, therefore where relevant, these extensions are described. The following subsections explore the inherent flexibility of smarter grids, flexibility as a service, the role of flexibility markets and flexibility in the context of local energy systems.

2.4.1 Flexibility in Smarter Grids

Although there are different definitions of flexibility within the literature these are generally variations of, as defined by Ofgem, *"modifying generation and/or consumption patterns in reaction to an external signal (such as a change in price) to provide a service within the energy system"* [160]. However, although this definition in general holds true, there are distinctions that can be made. For example, with the transition to smarter grids, there are inherent flexibilities that certain smart technologies unlock that would not typically be classified as 'providing a service' to the DNO, rather just inherent of the asset's functionality. This distinction is used to differentiate between instances where the DNO requires procurement of a service via a tendering process in comparison to making use of smart functionalities for flexible network management e.g. OLTCs or soft open points.

The following describes several of the technologies that provide DNOs with the ability to flexibly operate their networks.

Meshing: Meshing moves away from conventional radial network design with a single common point of failure to a more integrated topology allowing for alternative pathways of powerflow in the event of an outage. Beyond outages, meshing enables capacity management through the distribution of power to reduce loading and utilise unused assets whilst meeting the same demand [75]. Historically, normal open points were used to provide alternative routes of electricity supply in case of planned or unplanned power outages. However, in recent years, soft open points in the form of power electronics which are considered to be smarter and allow for more flexible control of power and voltage have become an advantageous alternative though have yet to be used at scale. Whilst the benefits of meshing in the distribution network are evident, network design and subsequent protection schemes are exceedingly more complex.

Dynamic voltage management: At present, most primaries in GB are OLTCs with off-load tap changers used at ground mounted secondaries, therefore there is scope to replace these with OLTCs for voltage management deeper in the network. Historically, standard off-load tap changers were installed and field engineers would have to manually change the transformer's tap position, taking the transformer out of service to do so. With the uptake of LCTs and DG, voltage is becoming increasingly variable and OLTCs provide a means of flexible voltage management [75].

Phase balancing: In the development of LV distribution networks, network planners typically try to balance the network with symmetrical distribution of load across the three-phases. This ensures maximum utilisation of available cable capacity, minimisation of losses and reduced asset degradation. However, this can be an extremely challenging undertaking and some form of asymmetrical load distribution across individual phases exists in most LV networks, meaning that one phase will typically approach its maximum thermal capacity whilst the other two phases remain underutilised. Therefore, redistribution or rebalancing through manual intervention is often seen as a 'low hanging fruit' solution to releasing spare capacity and deferring reinforcement. However, this requires visibility of all existing phasing and would take time to implement. As an alternative solution, the concept of switching to the use of three phase supplies has recently been gaining momentum (in part for existing households though predominately for installation of new builds) [75]. This would help to ensure that demand is equally distributed and would be a relatively straightforward approach to implement though at additional material cost. Smart dynamic phase balancing through use of power electronics would give DNOs the ability to flexibly balance demand across the phases without any form of permanent manual action by engineers in the field (beyond implementation). This would require monitoring and visibility of the network though would allow DNOs to take a more flexible approach to network management. However, although dynamic phase balancing is a potentially viable solution, there are concerns for use where existing three phase connections are installed [75].

Beyond these technologies, the following describes how DNOs in GB are currently managing existing network capacity constraints by adopting and offering flexible solutions to defer reinforcement and accelerate the connection of DG. At present, the solutions described tend to be applicable for larger commercial generating units and either aim to either fully deter network reinforcement or defer until reinforcement is carried out.

Active Network Management (ANM): ANM facilitates the connection of new DG by including curtailment requirements within connection agreements that would be enforced during constraint periods through autonomous control and network communications [67], [68]. Generators connected to the distribution network through this arrangement are typically referred to as 'non-firm' connections. The first ANM scheme in GB, going operational in 2009, was designed by Smarter Grid Solutions for deployment on the Orkney Islands, where conventional reinforcement of installing a new subsea cable would have cost approximately £30 million compared with the ANM scheme at a cost of £500,000[8] [162]. Several years on, DNOs in GB are now offering ANM as a Business as Usual (BaU) option.

With this arrangement, the long-term success of a new connection from the DG owner's perspective is largely dependent on the level of enforced curtailment throughout the lifespan of the asset. This has the potential to become problematic as curtailment levels may vary from initial estimations, placing significant reliance on the accuracy of the curtailment forecasts by the DNO. Independent forecasts and technical analysis are generally obtainable via consultancies to evidence the business case for connection. However, independent analysis would require additional cost and time. Therefore, the ANM approach fundamentally puts the overall project risk with the developer which can act as a deterrent for the connection of new DG in constrained areas of network regardless of resource availability. Whilst DG operators seek to profit from these installations, there is potentially a mutual benefit for the end consumer (lower overall cost of achieving net zero), indicating that the DNO should have to shoulder a portion of the curtailment risk. It is also noted in the likes of [67], that as the DNO is the only party to have suitable expert knowledge of their network and the existing constraints, they are best placed to manage the scheme and therefore a portion of the curtailment risk associated with the long-term operation. In [163], curtailment risk as well as the potential benefits and challenges associated with DNOs underwriting curtailment risk are further discussed.

The method of curtailment has an instrumental role in the operation of an ANM scheme and as the network continues to evolve, existing principles of access are brought under scrutiny, raising concerns that existing schemes and connection agreements are not fit for purpose given the levels of low-carbon generation expected to connect in the coming decades. In GB, the 'last

[8]The Orkney ANM scheme successfully deferred network reinforcement for several years. However, due to the unique geographic location and climate conditions on Orkney, by 2012 it had reached its capacity limit. As a result, in September 2019, Ofgem approved a £260 million 220 MW transmission link between Orkney and mainland Scotland (subject to conditions) [161].

in first off' approach is predominately used for DG curtailment due to its administrative simplicity, ensuring that the last non-firm generator to connect is the first to be curtailed. However, as discussed in [164], this can lead to excessive curtailment of generation to relieve specific network constraints and does not necessarily guarantee the optimal use of resources. Several other prominent curtailment options including: Pro-rata, Shedding Rota, Technical Best, Greatest Carbon Benefit, Most Convenient, Generator Size and Market Arrangements are described in [164] though have yet to be demonstrated at scale.

Single Generator ANM: this connection type is a simplified version of ANM where a single generator is managed with regards to a maximum of two constraints [165]. This option is typical for those in rural locations e.g. farmers seeking to connect smaller single generating units for private use.

3rd Party ANM: where for example, multiple independent generators manage their export capacities to meet a given contracted capacity, therefore maximising the existing network capacity by capitalising on technology diversity [165]. Alternatively, a less common though potentially viable approach is for larger generators to electrify proximity demand e.g. electrification of heat and transport, increasing demand and subsequently reducing the constrained export capacity (this approach would be expected to have wider network implications).

Timed Connections: this connection option aims to capitalise on diversity within the network, allowing generators to connect and export during specific time periods. For example, in areas with high penetrations of solar PV, this option would allow wind generators to connect and supply during non-daylight hours.

Contractual: arrangements are agreed and tailored within individual connection agreements that facilitate a limited export capacity for the generator until full capacity is available. For example, where the connection of the DG is completed in advance of the reinforcement required to accommodate the full export capacity. This chimes with a shift in focus to facilitate 'ahead of need' investments.

Intertrip: used for instances when two circuits are required, should one fail, with additional generation the capacity of the remaining circuit may be exceeded. To prevent this, the intertrip connection option disconnects the generator in the event only a single circuit is available, deferring the need for network reinforcement.

In summary, the flexible options described aim to defer network reinforcement and enable the connection of DG to constrained areas of the network. In terms of flexible DG connection options, these solutions primarily involve curtailment or disconnection of generation against specific criteria. Therefore, although these solutions can be cost effective and practical in deferring network reinforcement and accelerating the connection of DG, as the need to connect renewable generation increases significantly in tandem with a growing need to maximise renewable resource availabilities their effectiveness and suitability as viable long-term solutions are relatively limited. A more attractive solution to minimise the need for curtailment of DG and to also accelerate the connection of new DG whilst maximising the renewable energy potential available during times of high resource availability is to procure flexibility as a service e.g. modifying demand consumption patterns or through utilisation of storage.

2.4.2 Flexibility as a Service

Although DG is highly variable and can effectively be 'turned down' through curtailment, its value as an attractive flexible service is somewhat limited and highly dependent on resource availability. Contact between the DNO and individual generators would be necessary unless automated via an ANM scheme, and curtailment would ensure that the maximum renewable energy potential is unmet. As such, consumers would effectively be paying for renewable generation to not be used which would be highly inefficient and undesirable. Use of spatial and temporal forecasting can provide an indication to the levels of renewable generation output over a given time horizon to provide insight into when curtailment may be necessary, this can provide insight into when a flexible service could be used to avoid curtailment. Nevertheless, should alternative more desirable options be unavailable, curtailment would still present as a favourable network management option.

Therefore, with curtailment of DG aside, this section describes the flexibility requirements of the DNO, how flexible services may be procured and what types of services might be available in the future with focus primarily on the flexibilities offered by the decarbonisation of heat and transport. The wider impacts on society and the economy are also considered.

2.4.2.1 Service Requirements

The ability to procure flexibility as a service is highly beneficial for network management but also for local businesses, and consumers who have the ability to profit from such services. When considering flexible services from the perspective of the DNO, it is crucial to understand the service requirements and the varying types of services available to meet those requirements. The flexible services currently sought after are summarised as follows [166]:

- **Sustain:** defer/avoid network reinforcement through peak shaving of forecasted demand.
- **Secure:** provide network support during scheduled maintenance.
- **Dynamic:** provide network support during fault conditions that coincide with planned outages.
- **Restore:** provide network support during fault conditions.

At present, significant attention is being placed on flexible services to 'Sustain', with focus on constrained areas of the network, where DNOs can utilise flexibility from distributed assets (if there is the availability and business case to do so) for specific time periods to alleviate constraints in the network. For example, certain technologies e.g. energy storage from a commercial perspective can be connected with the sole intention of providing a flexible service in these areas, whereas in parallel there is an increasing opportunity to capitalise on the inherent flexibilities of variable LCTs despite flexibility provision not being the primary function of the assets. In this case the level of flexibility available for procurement is dependent on a variety of factors including asset functionality i.e. do the technologies have the required monitoring, control and communications necessary to offer flexibility as service at the timescales required? e.g. V2G in the case of EVs. The coordination of many small-scale LV-connected flexible assets such as EVs to facilitate a larger net effect at higher voltages is of value in these areas.

To identify areas of the network that are constrained and that could benefit from these flexible services, DNOs in GB such as SSEN use Constraint Managed Zones (CMZs) as defined in [166] as *"A geographic region served by an existing network, where network requirements related to network security of supply are met through the use of flexible services, such as Demand Side Response, Energy Storage and Stand by Generation."* The specific type of flexible service required is largely dependent on the constraints and network characteristics within each CMZ. Whilst DNOs have identified that the services outlined are currently required, these requirements are expected to evolve and potentially vary between DNOs. In 2019, UKPN released their flexibility roadmap [167] identifying what they foresee to be the flexibility requirements of a future DSO, describing how the contracts may operate and the expected procurement process/time. Identifying when differing services are required allows for a better understanding of how to ensure the necessary services are available for procurement and how they can be optimally procured at least cost.

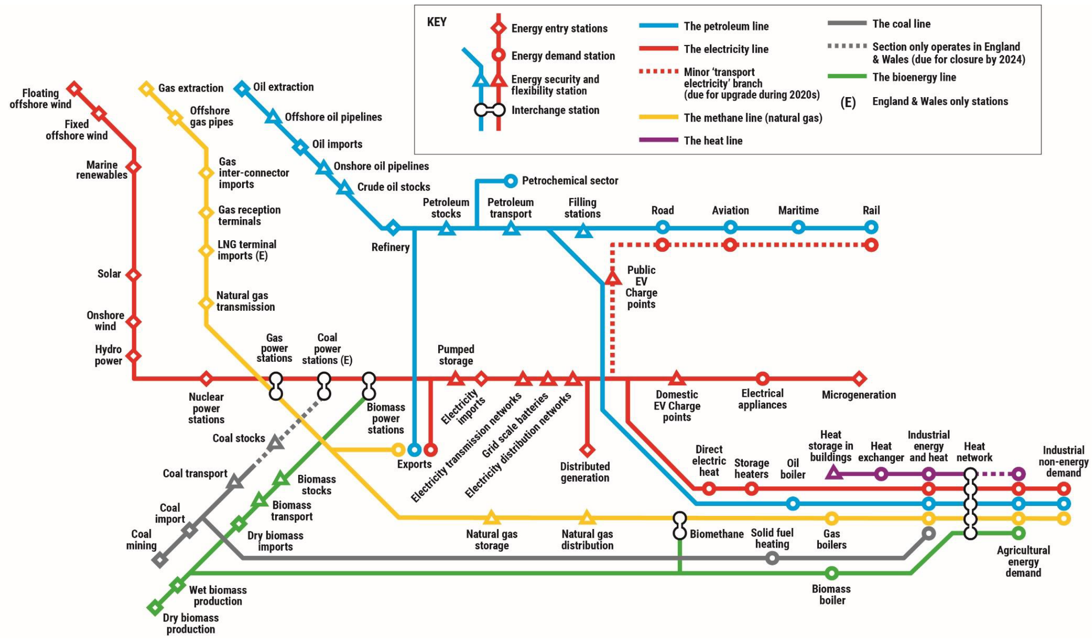
2.4.2.2 Supply-Side Resource Flexibility

Historically, flexibility has typically been provided from the 'supply-side' where output from electricity generators would be adjusted to ensure supply always met demand [160]. With the decarbonisation of heat and transport, and the transition to a whole energy system. There are several potential avenues for supply-side resources to influence the amount of flexibility available in the electricity system e.g. depending on the decarbonisation pathways taken and levels of technology diversity, the extent of electrification will vary impacting the levels of flexibility available for procurement. Flexibility between supply-side resource entities is an entirely different form of management that will have an impact on the electricity system.

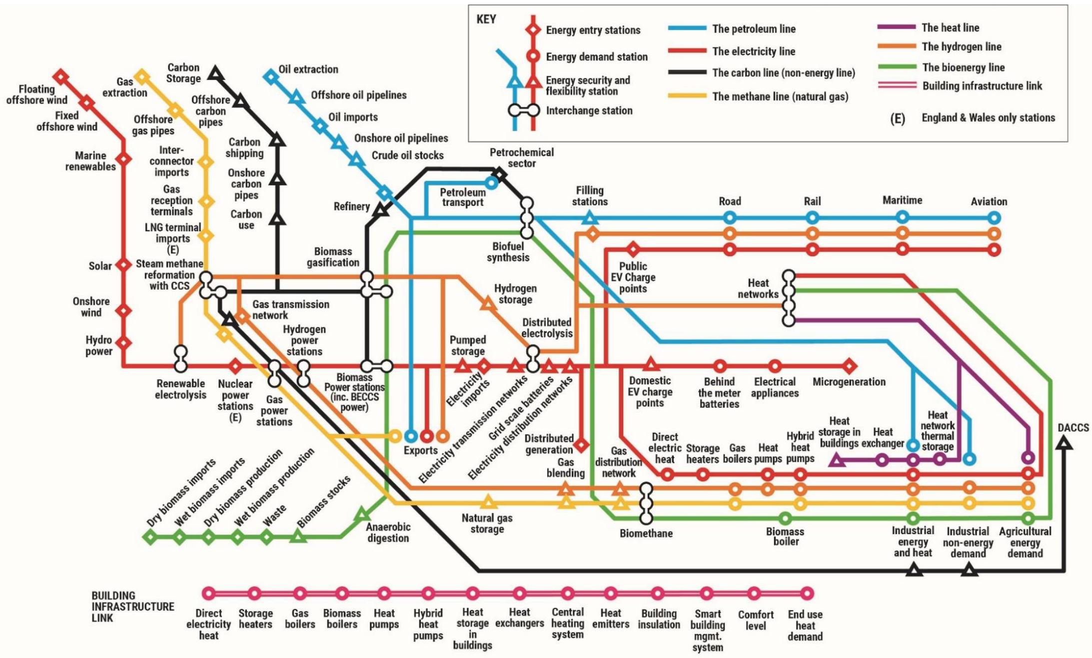
Figure 2.4 presents a representation of Scotland's energy map in the 2020s and 2030s [168]. The figure highlights the interactions and flexible common source points between different energy vectors and where certain demand types can be met by multiple different sources. Identifying that there is scope for flexible multi-vector management and optimisation subject to resource availabilities, capacity constraints and demand requirements.

2.4.2.3 Demand-Side Flexibility

The uptake of LCTs has significant potential to: reduce the volume of renewable energy not used, minimise network losses and ensure network constraints are met whilst providing cost benefits for the consumer [101]. From a network management perspective, the inherent flexible nature of these technologies could be used for peak shaving and curtailment mitigation by time-shifting and reducing local demand e.g. charging energy storage and EVs during times of high output from DG when demand is low or through discharging of energy storage in times when output from DG is low and demand is high. Alternatively, they could be used as a response



(a)



(b)

Figure 2.4. Representation of Scotland's energy map [168]. (a) 2020s. (b) 2030s.

measure, supporting the network in response to outage events e.g. EVs through V2G can be used to offset the spike in electrified heating demand that would occur after a loss of supply during winter. Beyond LCTs, 'smart' appliances such as fridges and dishwashers can also be used in demand-side management or response applications.

The management and coordination of these small-scale LV-connected variable and smart technologies is exceedingly more complex than managing the coordination of large commercial generators and demand in an ANM scheme for example. Particularly due to the size and expected volume of these technologies but also in terms of the decarbonisation of heat and transport, they are for the most part consumer-driven and influenced by a variety of local conditions. The uncertainty associated with these assets and their characteristics (different makes and models of EVs/HPs may yield differing usage patterns as they are subject to differing limitations amongst other challenges) brings an additional degree of complexity when identifying the volume of capacity available for flexibility procurement at any given instance. Furthermore, certain technologies are likely to have more flexibility potential than others at different time-scales (e.g. daily peak shaving and response in comparison with season demand shifting through storage). For example, in [93] EVs are considered to have more potential for flexible demand side management applications than HPs. The flexibilities offered by low carbon heating solutions and energy efficiency measures is a developing area of research, with innovative technologies such as phase change materials and thermal batteries showing early signs of flexibility potential [169], [170].

Another manifestation of demand-side flexibility is in consumer decision making and their ability to take different approaches to meet their heating and transport requirements e.g. using different modes of transport to satisfy their travel requirements or by taking alternative measures to achieve thermal comfort as previously identified. These socio-technical decisions are an alternative form of flexibility e.g. development of 20-minute neighbourhoods or increased use of public transport could see a reduction in car miles and subsequently EV usage. This could result in less day-to-day constraints on EV charge requirements and greater flexibility potential in comparison to a future scenario with higher EV usage. This fits with a growing narrative, as explored in this thesis, that there is a need to better understand what impact different future pathways in energy demand, encompassed by a complex web of interactions between societal, economic and geopolitical shifts, and decisions in public policy will have on the electricity system and flexibility at the local-level.

In the near-term, there is an opportunity to utilise this flexibility along with the flexibilities offered by LCTs to accelerate the uptake of LCTs as networks become more constrained and to support network operation in the long-term. In terms of the flexibility versus reinforcement debate, in [171], a framework was developed to inform DNO investment decision making. However, key deployment questions regarding network reinforcement and flexible management techniques are not yet fully understood and there remains a need to progress the modelling techniques used to underpin such frameworks. Although DNOs are currently taking a flexibility first approach, in certain instances reinforcement will be unavoidable. Therefore, any future scenario is likely to include both reinforcement and flexibility options in the development of the network, and in certain instances a combination of both. A lack of visibility and automation contributes substantially to the uncertainty surrounding future network planning and management in this regard. Furthermore, an intermediary or market arrangement will likely be required to coordinate and manage demand-side technologies to unlock the full flexibility potential.

2.4.2.4 Virtual Power Plants and Aggregators

With a shift to active distribution networks and with increasing penetrations of DG and LCTs the concept of virtual power plants (VPPs) has been developed over a number of years where individual distributed assets would be aggregated to provide system visibility and controllability whilst acting similar to a transmission connected generator [172]. The initial concept of a VPP was for operation at the interface between the transmission and distribution network, thus with the intention of mainly providing system level services to the system operator. For individual assets typically connected at HV or LV in the distribution network, the technical feasibility, cost-effectiveness and risk associated with participating in existing electricity markets and the contractual obligations of providing services to the system operator are significant hurdles for participation and service provision [172]. Therefore, the VPP concept seeks to overcome this by providing a diversified representation of all distributed assets in the form of a single profile that encapsulates asset characteristics and network limitations, allowing for distributed assets to have visibility of electricity markets, provide support through ancillary services and ensure optimal use of all available capacity within the network. This individual profile then allows the system operator to use the VPP as they would with a standard transmission connected generator, maximising the flexible capacity of assets connected at the distribution level without the complexity and risk associated with independent participation. This would involve the aggregation and optimisation of a significant amount of assets within a single VPP and also introduces complexities with who performs the aggregation e.g. the system operator, DNO or independent entities (aggregators) and with how the interactions between the differing parties are structured to ensure efficient operation and oversight e.g. to ensure a request by the system operator for services at a specific GSP does not result in operational challenges for the distribution network. Givisiez et al. conduct a review of proposed TSO-DSO coordination models within the literature [173] and categorise them into three core models as shown in Figure 2.5.

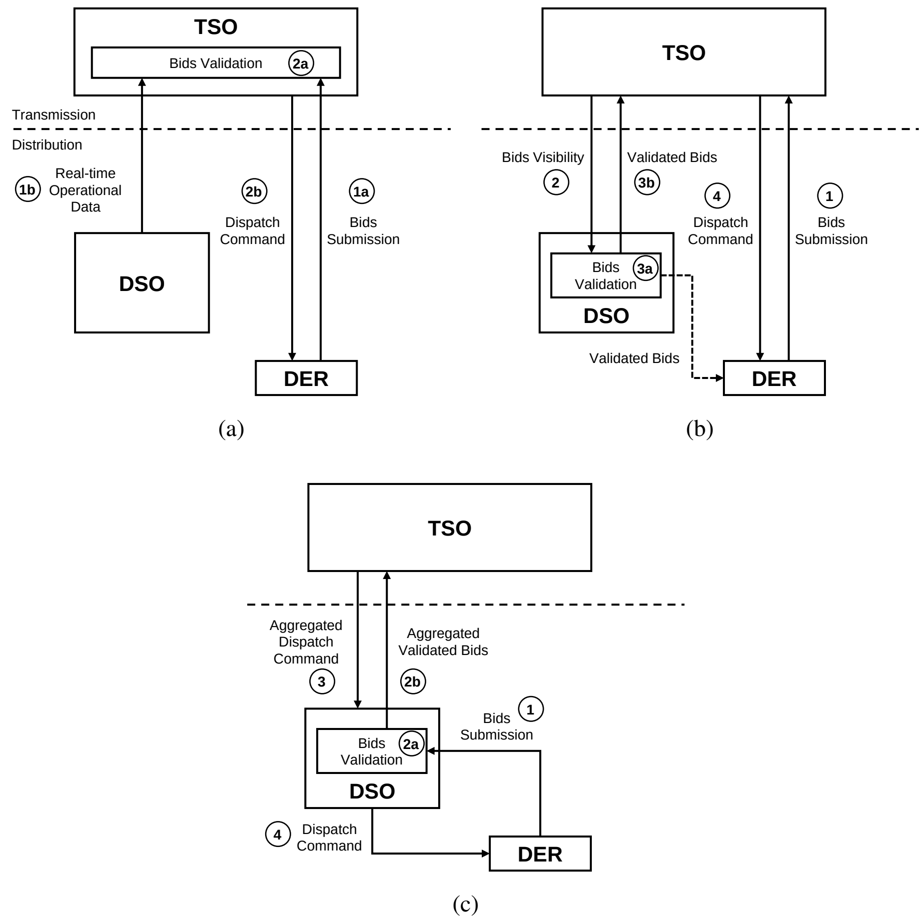


Figure 2.5. TSO-DSO coordination models [173]. (a) TSO. (b) TSO-DSO Hybrid. (c) DSO.

Givisiez et al. also categorise the optimisation approaches proposed within the literature for determining the most cost-effective solution that provides a given service whilst meeting distribution network constraints, namely: distributed optimisation, hierarchical optimisation and centralised optimisation. For example, the hierarchical optimisation approach involves a bottom-up approach where the problem is divided into subproblems that make decisions locally and communicate the outcomes upstream e.g. at the primary transformer level, where an aggregated diversified single profile could be used as an alternative to managing and optimising all sparsely located assets under a specific GSP. Such approaches could reduce the level of computation necessary and the volumes of data being transferred. This approach would also allow for the DNO to procure flexibility services to manage distribution network constraints and for local balancing of generation and demand.

As part of the Power Potential project, NGESO and UKPN trialled a Distributed Energy Resource Management System (DERMS) that aimed to provide active and reactive power services at the transmission level from assets connected to the distribution network [174]. A high level overview of the DERMS coordination approach is presented in Figure 2.6.

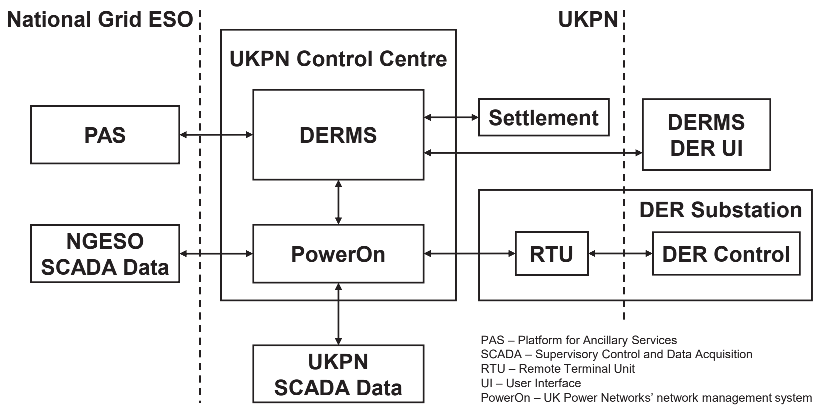


Figure 2.6. Overview of the DERMS in the Power Potential Project trialled by NGESO and UKPN [174].

This demonstrates the scope for coordination and control of technologies connected in the distribution network to offer flexible services across the different voltage tiers, emphasising that flexibility as service in this application has significant potential as a network management function for a number of different electricity system actors. However, challenges exist with interactions between these actors, market complexities and the approaches used for managing asset coordination in respect of distribution network constraints. Additionally, concerns with the computational times involved in the transmission of large volumes of data between actors and the cyber security risks are emphasised. At a local-level, a flexibility service management system could support local distribution network operation and management within the bracket of a DERMS that facilitates support for transmission network operation and management. However, as noted the coordination and scheduling of assets capable of providing such services can become significantly complex when considering the scales involved. Therefore, in certain instances e.g. sparsely located rural locations it may be more practical to coordinate and manage assets locally for a local community benefit and then for a local aggregator to manage interactions with the future DSO.

2.4.2.5 The Role of Flexibility Markets

The procurement of flexibility for services requires interactions between buyers (DNOs and the system operator) and sellers (flexibility providers such as aggregators). Therefore, flexibility markets or bilateral agreements between entities is necessary to facilitate such transactions. A market for flexibility relates to a regulated trading platform for flexible services used to facilitate transactions between different buyers and sellers, consisting of a market operator, market participants, and market clearing mechanism [175]. The Piclo Flex platform which is an independent marketplace for trading energy flexibility services in GB is an example of an existing flexibility market [176]. The marketplace provides DNOs with the ability to procure flexibility services based on technical, temporal and spatial requirements [176]. Figure 2.7 provides an overview of the Piclo Flex market structure.

The platform has four primary stages which are summarised as follows [176]:

- **Procurement:** This is where competition is initiated by system operators (including DNOs) by advertising their flexibility requirements and monitoring flexibility service provider assets engaged in the market, followed by qualification of participants. This includes two qualifying requirements; a dynamic purchasing system and an asset assessment against location and capacity criteria. From this, flexibility service providers will submit bids within constrained procurement windows and system operators will then either accept or reject.
- **Operations:** This relates to the process prior to asset dispatch where asset availability would be monitored until dispatch is required, followed by dispatch instructions and

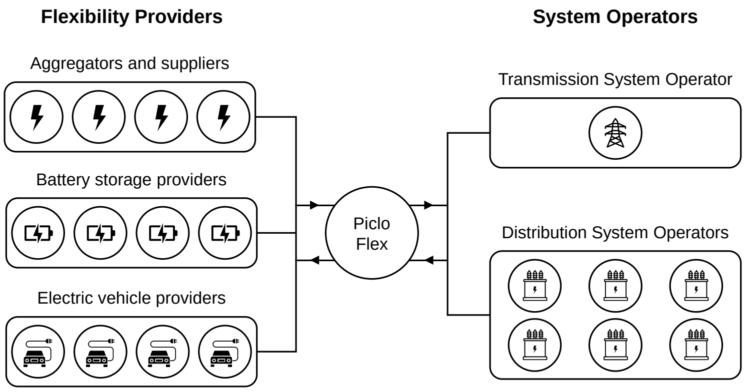


Figure 2.7. Marketplace structure for the Piclo Flex flexibility trading platform [177].

communication between both parties indicating status of dispatch acceptance.

- **Settlement:** This involves verification of the service according to contracted obligations and invoicing upon confirmation.
- **Exchange:** This is a secondary trading marketplace that allows users to buy and sell existing flexibility contracts where service providers can advertise contracts to sell within a set timeframe and other providers can submit bids to win contracts. These are either accepted or rejected after the bidding window closes.

Whilst flexibility markets present as a potential valuable mechanism for flexibility service provisions and procurement. These are not without their limitations, particularly in the context of local flexibility markets. For example, local markets for rural areas or small-scale communities could lead to fragmented markets with limited participation and less liquidity. The actors or consumers looking to (or best placed to) participate in the market may be limited by technological barriers (communications and IT infrastructure) and knowledge on market participation (e.g. an understanding of renewable generation forecasting that will inform DNO flexibility requirements). In these situations, the costs of implementing the necessary technologies to participate in the market could outweigh the potential benefits. Long-term participation may also become unviable should DNOs opt to reinforce the network instead of relying on flexible services for security of supply reasons. Beyond these concerns there is the alignment of incentives, regulatory and policy challenges for scalability and the complexities with existing market arrangements.

2.4.2.6 Social and Economic Considerations

The concepts of flexibility capital and flexibility justice are described in [178], where flexibility capital is defined as *"the capacity to responsively change patterns of interaction with a system to support the operation of that system"*. It is recognised that across society there is significant social and spatial diversity such that flexibility capital would vary with the underlying determinants of this diversity. The authors in [178], suggest that the clearest of these determinants is affluence and summarise the interaction between flexibility capital and affluence in Figure 2.8. Broadly indicating that more affluent consumers are likely to have increased loads and greater access to technologies which directly afford flexibility in comparison with less affluent consumers who without intervention are less likely to have access to such technologies. The flexibility capital of less affluent consumers is more likely to stem from changes to daily activities and routines. This emphasises that in terms of flexibility capital, the more affluent are likely to have the ability to offer flexibility on their own terms, whilst the less affluent and those in fuel poverty are likely to be under stricter financial pressure as to when and how they economise their flexibility capital [178]. As such, it can be argued that consumer flexibility can be framed as a justice issue.

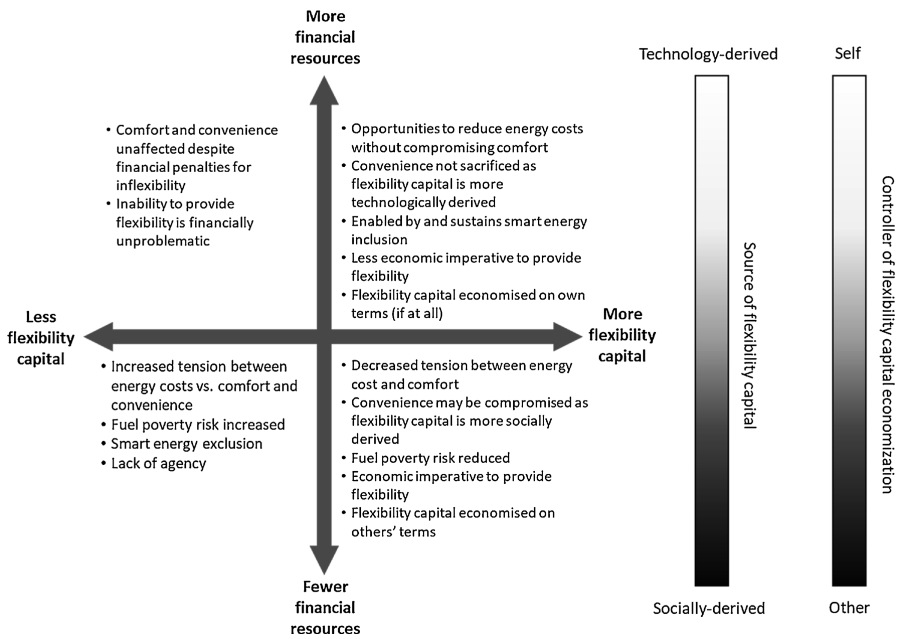


Figure 2.8. Generalised relationship between flexibility capital and affluence [178].

This echoes that the level of flexibility capital will vary in different regions but also emphasises how social dimensions will influence the rate of LCT uptake and utilisation. Indicating that flexibility capital will continuously change as the network evolves. This demonstrates a need for a greater understanding in quantifying the amount of flexibility available at the local-level. This also further complicates the challenge of network development i.e. to avoid a scenario where the DNO has to incrementally reinforce portions of the network when challenged with a new connection they may opt to reinforce all associated infrastructure in the area knowing that the infrastructure will be underutilised until such a time as more LCTs are connected. However, due to upfront costs and disruption this cannot be feasibly employed universally and therefore the DNO may look to make use of a temporary flexible solution that accelerates uptake and defers reinforcement. That solution must be adaptable and fluid as more LCTs are connected and may also become obsolete at 100% penetration when different management requirements may be necessary. By taking a flexibility first approach, it is vital that DNOs are able to quantify flexibility and are aware of how consumer flexibility capital may evolve, particularly as underlying socio-technical dimensions have the potential to unintentionally inform network decision making.

From a consumer economic perspective, flexibility trials have already been conducted in the UK at scale e.g. a recent trial saw over one million households participate and support the grid upon request from November 2022 and March 2023 where an estimated 2.92 GWh of energy was shifted from peak periods (the total power reduction during an event was, on average, 87 MW – equivalent to an 18% change in energy demand), and 100% of the grid's requirement was satisfied [179]. In participating, households were paid a fixed incentive which varied between events ranging from £2/kWh to £4/kWh [179]. In terms of social considerations, those who continuously participated over the trial period tended to be those of higher income, households with a high degree of energy automation and older households (in terms of demographic). An interesting conclusion drawn from the trial was also that the amount customers earned affected levels of sustained engagement, potentially raising concerns with liquidity and using local flexibility markets to resolve distribution network issues.

2.4.3 Local Energy Systems and Flexibility

In recent years, as evidenced by Ofgem's review into local energy system operation, local energy systems have formed a large part of the energy security debate surrounding electrified heating and transport [81]. With a formidable role in decentralisation, local energy systems would see areas operated locally for a local benefit with less dependency placed on the supply chain. These systems are inherently reliant on the flexibility of distributed assets and smart functionality. Whilst local energy systems would operate similarly to that of an ANM scheme e.g. through the coordination of local assets via a communications and control infrastructure. Unlike ANM – the purpose of which, at least in GB, is to accelerate the uptake of DG – local energy systems could be used to provide additional network services such as increasing network resilience and ensuring security of supply. Such services are highly desirable when considering rural networks due to the associated supply challenges. However, an added complexity exists in that whilst DNOs are currently responsible for network operation and planning for future energy demand, local authorities are responsible for meeting local heating and transport requirements. This extends beyond the historical role of the DNOs and potentially requires local authority input in network planning decision making which also extends beyond the remit of the local authority (further described in [180]). With this, Ofgem considers that there is currently a lack of co-ordination between these entities and that there is potential for conflicts of interest which could add unnecessary costs to customers and delay the transition to net zero [81]. As such, the broad theme of local energy systems and flexibility is further explored in this section.

The study of microgrids has been prevalent within the literature for a number of years [181]–[183] and although the general principle of operation holds true across most of the literature, there is a degree of ambiguity as to what physically constitutes a microgrid in terms of size as no standard or definition exists. Therefore, to avoid this ambiguity, islanding which relates to the sectioning of areas within the network and is defined by the Institute of Electrical and Electronics Engineers (IEEE) 1547:2018 Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces [184] is considered. This standard describes the differences between the two forms of islanding; unintentional and intentional, and clarifies the associated definitions.

Unintentional islanding refers to when an uncontrolled island is formed inadvertently within the network, typically through a fault occurring. For the island to form, generation and demand must be balanced, therefore the circuit breaker must open without triggering further downstream faults causing imbalance. As expected, this phenomenon can introduce several safety concerns and operational challenges. As previously identified, LoM protection is used to disconnect the DG and prevent unintentional islanding. For conventional operation and unintentional islanding detection, the advantages and disadvantages of these protection methods are generally well understood. However, when considering intentional islanding the protection requirements typically become more challenging.

Intentional islanding involves the isolation and balancing of a dedicated section of network i.e. formation of a microgrid. An intentional island refers to an area of network within a defined boundary that can be disconnected from the network and where local generation supplies local demand through a controlled voltage and frequency. There are numerous benefits to this including:

- can ensure security of supply in the event of wider network faults;
- less distance between consumer demand and generation source (reduced network losses);
- the ability to provide resiliency as a service;
- requirement for increased network visibility; and
- increased blackstart capabilities.

The intentional islanding process falls into two categories, unscheduled and scheduled, whilst having multiple system states. Unscheduled islanding as defined within IEEE 1547:2018 relates to when an island is formed automatically through the detection of abnormal system conditions e.g. breach of statutory voltage and frequency limits. Although relay threshold settings would have been predefined, the unpredictable nature of system conditions ensures that the decision to island would have been unscheduled by the DNO even if monitored in real-time. Scheduled islanding relates to islanding actions known in advance e.g. manual action by the DNO to conduct maintenance or through economic dispatch decisions. With this, there are predominately four system states throughout the intentional islanding process each requiring differing control actions: grid connected, transition to island mode, island mode and reconnection.

Intentional islanding (or use of microgrids) is a network management technique that is predominately used to ensure security of supply by enhancing network resilience. Where in the context of this work, network resilience is broken down into three categories: Prevention, Containment and Recovery [185]. Described as follows:

- **Prevention:** relates to actions that primarily seek to reduce the frequency of supply interruptions.
- **Containment:** relates to the actions taken to prevent the spread of an interruption and limit the impact.
- **Recovery:** relates to the actions taken to reduce the duration of an interruption.

A limitation of this technique is the potential of intentional islanding to negatively impact network resilience. For example, in having the ability to disconnect an area of network there is a probability this can occur when unintended by the DNO. This could occur for a variety of reasons such as: equipment failure, incorrectly set protection settings or through human error. Assuming the associated control recognises this and responds as intended, given the circumstances this could have a negative cascading effect and lead to an undesirable system state. Additionally, the functionality to intentionally island has increased communications, protection and control requirements which have their own limitations and challenges.

Fundamentally intentional islanding or microgrid technology is reliant on an inherent smart functionality and flexible assets, primarily when in island mode. However, when in grid-connected mode – which would typically be the primary state for the vast majority of time – this enhanced operational smart and flexible functionality that exists can provide flexibility as a service (with appropriate oversight) to support wider network operation and management. Therefore, there are parallels between microgrids and local energy systems, arguably the only fundamental difference is the intentional islanding functionality which ideally would provide an additional layer of security of supply and enable resiliency as a service. This would typically be more applicable for areas that already have a higher than average customer minutes lost e.g. remote rural villages or communities supplied by overhead lines that span challenging terrains and must endure adverse weather conditions. As an example, the 100% renewable local energy system in Simiris Sweden has the ability to operate in what has been termed as 'virtual island mode' (considered to be the primary operating state though with the capability to island as necessary) where the network is balanced locally to reduce reliance on the grid supply without the need to disconnect, therefore, essentially operating ‘grid neutral’ but still using the grid frequency [186]. As a result, interactions between the local energy system and the grid are limited to instances when there is a local imbalance and import/export is required from/to the grid, e.g. should the local demand exceed the available output from local generation and storage. However, with this small-scale balancing approach and by frequently operating assets closer to their limits, asset degradation may increase resulting in a reduction in asset life span. More broadly, due to the capital expenditure of installing the communications and control infrastructure, this technology has predominantly been used at a commercial level, at least in the global north, where security of supply is essential and less so at a residential level e.g. prisons, university campuses or commercial estates. In a practical context, there are numerous additional challenges relating to ownership, maintenance, and with the market arrangements and regulatory frameworks that would see these become a BaU solution. In cases that are community focused or reliant on local community energy such as on small Scottish islands, the challenges extend to understanding of the technology and community engagement.

2.5 Chapter Summary

The work presented in this chapter has provided an extensive overview of the decarbonisation of heat and transport, distribution networks and flexibility in the electricity system. The chapter builds on key motivational elements raised in the previous chapter by providing an in-depth contextual view and positioning of the work presented in this thesis. Through better understanding of the contextual positioning of the work, the key contributions of this thesis should be more easily distinguishable from the existing literature reviewed in each of the subsequent chapters.

The work first focused on the decarbonisation of domestic heating, exploring the role of buildings and occupants, and the technologies available to support the shift to low carbon heating. It was found that, hydrogen, district heating and HPs present as the most viable solutions for heat decarbonisation at scale. However, hydrogen distribution via the gas network, district heating and GSHPs specifically all have significant upfront installation/upgrade costs and lead times. This tends to make ASHPs the most favourable solution in terms of practicality and affordability for short- to medium-term heat decarbonisation at scale, despite the related limitations discussed. Therefore, in the context of this thesis, ASHPs are used as the primary low carbon technological heating option for the investigations carried out in subsequent chapters.

The chapter then focuses on the decarbonisation of domestic transport which describes the relative challenges and the mechanisms by which this can be achieved with respect to the net zero timeframe. It is identified that a diverse mixture of both demand- and technology-based solutions will be necessary to meet net zero targets. However, for the technology-based solutions, EVs are considered to be the most viable candidate for rapid decarbonisation at scale. The uptake of EVs is expected to have significant impact on the electricity system and the existing infrastructure due to their unique consumer-driven demand requirements. Therefore, in the context of this thesis, EVs are used as the primary low carbon technological transport option for the investigations carried out in subsequent chapters.

Focus was then shifted to distribution networks and the existing operation, planning and management practices which was followed by a detailed overview of distribution network and DNO evolution, including the transition from passive to active distribution networks, the challenges with decentralisation and the uptake of DG, and the transition from DNOs to DSOs. This was followed by an overview of flexibility in the electricity system including: flexibility in 'smarter' grids, flexibility as a service, and flexibility in local energy systems. This provides the basis for understanding the evolution of distribution networks and their operation and planning requirements.

Chapter 3

A High-Resolution Geospatial and Socio-Technical Methodology for Assessing the Impact of Electrified Heat and Transport on Distribution Network Infrastructure

3.1 Introduction

3.1.1 Motivation

DNOs face the challenge of ensuring appropriate investment in infrastructure and the development of new management solutions in response to increased electrification from the decarbonisation of heat and transport [67]. Diversity in technology type, consumer behaviour, increasingly variable weather patterns, variation of the building stock and the network assets is expected to have a significant impact on the extent of this electrification, particularly as certain areas are likely to engage in radically different decarbonisation pathways at varying rates [64], [66].

As EV and HP demand is in-part consumer-driven, this manifests in a distinct set of locally sensitive demand profiles that are inherently driven by consumer lifestyle and comfort or by wider societal rhythms such as work patterns and affordability [112]. Therefore, in recognition of consumer diversity and household energy variability [95], [96], [187]–[189], the way that LCTs are adopted and used will be influenced by the distribution of socio-economic factors within a local area. This, in turn, has the potential to impact network decision-making across different regions.

DNOs in GB and other actors in this space, specifically policy makers and local authorities are aware of these challenges [76], [190]. However, at present, although there exists recognition of the issues pertaining to socio-economic factors and their impact on LCT demand and subsequent electricity network infrastructure, there remains a need for an enhanced modelling capability that can capture key elements of socio-technical and socio-spatial diversity to inform LCT demand consumption in different areas. There is also a growing requirement to reduce the uncertainty surrounding the impact LCTs of different types will have on existing infrastructure [191]. These insights will support place-based DNO decision making by informing the network planning requirements of infrastructure in various locations.

Such strategic 'intelligent decision making' of infrastructure can help to minimise network interventions (reduce regular reinforcement of legacy assets), minimise customer minutes lost and customer interruptions which incur heavy financial penalties, maximise profits, maintain (improve) network resiliency as the network evolves in the transition to net zero and as the penetration of intermittent technologies increases, to operate assets more efficiently improving longevity, reducing losses and increasing life-cycle value. Ultimately the intention of this work is to inform network planning in BaU operations and while DNOs are regulated, that does not mean that the regulator makes investment decisions for them: the DNOs are expected to use best-practice techniques to determine what investment is needed, and where other methods should be used to defer or avoid investment. Intelligent decision making of network infrastructure investment also has the potential to inform wider decarbonisation pathways and can support timely deployment of cost-effective decarbonisation solutions.

Therefore, this motivates the focus of this work to investigate – through high-resolution geospatial and socio-technical modelling – the combined impact of electrified residential heat and transport on key network infrastructure (specifically secondary transformers) and the influence of socio-technical and socio-spatial dimensions.

3.1.2 Contribution

The key contribution of this chapter is the development of a novel high-resolution methodology that enables assessment of electrified heat and transport impact on transformer headroom at scale using socio-economic indicators to inform the application of LCT consumption data. The methodology is applied to a fleet of over 4,000 secondary transformers (typically 11/6.6 kV-400 V in the UK as described in Section 2.3.1.3) distributed across the north of Scotland and a subset are used for the analysis. Findings are then analysed primarily from the perspective of the incumbent DNO but the implications and value of such modelling capabilities for other stakeholders e.g. policy makers and local authorities are also discussed. The novelty of the developed methodology stems from the following:

- The work carries out mapping of spatially linked gas demand and socio-technical/-spatial datasets and then through analysis identifies relationships between gas consumption and social deprivation/affluence. The relationships support generalised socio-technical analysis in the absence of sufficiently granular metadata and are used to support spatial and socio-sensitive LCT modelling.
- A localised HP modelling methodology that couples two established methods of converting gas demand to equivalent electrical heat demand is incorporated where the developed relationships between gas demand and social deprivation are used as inputs to the modelling. The benefits of this approach are shown by comparison with a generalised HP modelling approach that uses raw trial data as used in [87]. Findings from this analysis provide insights into the value of localised modelling with respect to socio-technical analysis.
- In addition to the localised HP modelling, the work incorporates modelling of EVs where EV charging schedules are synthesised from UK NTS data [192], [193]. This allows for a combined infrastructure assessment that accounts for both the electrification of heat and transport in consideration of socio-economic indicators.

The remainder of the chapter is organised as follows. Section 3.2 provides an in-depth review of the literature pertaining to the relationship between socio-economic factors and household energy consumption. This is followed by an evaluation of impacts from LCTs on key distribution network infrastructure and the use of socio-economic indicators in modelling the impact of LCTs on electricity networks. From this, gaps in the literature are identified, forming the justification for the work conducted in this chapter. Section 3.3 provides a description of the relevant datasets and the conditioning of each with respect to their application. The relative spatial mapping associated with each dataset and the relational analysis between key datasets is also described in this section. Section 3.4 provides an extensive overview of the developed methodology, describing in detail both the HP and EV modelling techniques used to underpin the approach and their relevant limitations. The mechanism used to assess transformer headroom is also described. Section 3.5 details the assessment scenarios and presents the results with accompanying analysis. Section 3.6 takes a wider contextual view of the presented findings from the perspective of the DNO and other key stakeholders engaged in the net zero transition. Finally, Section 3.7 presents a summary of the work described in this chapter.

3.2 Literature Review

3.2.1 The Influence of Socio-Economic Factors on Household Energy Consumption

It is well understood that energy consumption and resulting emissions are unequally distributed [72]. Research has been undertaken at national levels to describe this problem in more detailed contexts; studies focusing on energy use and resultant emissions in the UK have been many. For instance, Druckman and Jackson [194] explore patterns of household energy use in the UK at high levels of socio-economic disaggregation on variables including household type, index of multiple deprivation (IMD) and employment type, supporting the hypothesis that different segments have very different patterns of consumption. The areas of focus in [194] are the very least deprived (top 1%) and most deprived (bottom 1%) of households in terms of the IMD; it is found that energy consumption in the top 1% is approaching twice that of the bottom 1%. Generally, there is a wealth of research on the topic which is in strong agreement: household energy use increases with income (e.g. [95], [96], [187]–[189]) and is also heavily influenced by household composition (including household size and number of children) (e.g. [96], [195], [196]).

Where the research differs on this matter is often what conclusions are drawn from the analyses carried out. Chatterton et al. [197] use a Multiple Analysis of Variance technique to explore the dependency of energy demand in the UK – including direct gas, electricity and petroleum consumption – on a set of proposed explanatory variables covering demographics, socio-economics and the built environment. The analysis in [197] then focuses on the sub-set of these variables that are likely to set the degree of control a household has of their energy consumption, and how that relates to the level of energy consumed. It is concluded that those who are the largest consumers of energy have the highest incomes and the lowest levels of social deprivation, but also that they tend to be those who have the greatest opportunity to reduce their energy consumption, as also recognised in [178].

Research published on sector-specific analysis has been important for understanding the influence of socio-economic indicators on demand across different energy services. For example, Büchs and Schnepf [97] examine the associations between socio-economic factors and UK household energy consumption by sector (the three sectors are: home energy use from electricity and gas consumption; transport energy use from motor fuel, flights and public transport; and indirect emissions from food, clothing, etc.). It is reported that whilst all energy use is positively correlated with income, home energy use (i.e. gas and electricity consumption) is less sensitive to changes in these factors than transport and indirect consumption. Brand et al. [98] apply multivariate linear and logistic regression analyses to survey data from over 3,000 UK adults to examine the distribution of energy and emissions resulting from motorised passenger travel. Whilst income, education and tenure were found to be predictors of energy and emissions, the strongest independent predictors are listed as owning at least one car, being in full-time employment and having a home-work distance of greater than 10 km. Priessner et al. [198] conduct a multinomial logistic regression analysis of EV adoption and a set of socio-economic and psychological factors. They find that whilst a subset of the socio-economic factors do serve as predictors (gender, household size, number of cars), stronger prediction is afforded by psychological factors, including (as they term it) ‘cultural worldview’: respondents who rate their own worldview as less egalitarian and more individualistic are less likely to want to adopt EVs than their culturally opposing counterparts.

3.2.2 Evaluation of Impacts from LCTs on Key Distribution Network Infrastructure

Concerns from DNOs [199], regulators [200] and policy makers [201], [202] that the capacity of distribution networks may not cope with the increase in electricity demand from their adoption have contributed to the motivation in the academic literature to produce methods to characterise the likely impact of LCTs on electrical infrastructure. Sometimes referred to as spatial load forecasting, these methods have become an increasingly important tool for actors involved in planning and investment of power networks [203], [204].

This field of study is generally broken down into three parts:

1. Plausible levels of uptake of LCTs are modelled, which are generally returned as time-bound levels of penetration (e.g. $X\%$ of cars will be EVs by year Y).

2. Energy demand, or temporal demand profiles, of those corresponding LCTs are simulated, sampled or assumed.

3. Those demand profiles are assigned to nodes in a network that represent served customers (households) of an electricity network. Specific network analysis is not always present; rather, some studies seek to return the quantity of energy demand for a particular area.

Methods used for modelling technology uptake varies significantly between studies, and includes statistical methods such as Bayesian models [205], regression analysis [206]–[208], agent-based modelling [73], [209], [210] and scenario development [211], [212].

Some studies draw upon the significant impacts of socio-economic indicators on energy demand in modelling LCT uptake. For example, Van der Kam et al. [207] use a non-linear regression method to examine the influence of several socio-economic indicators, including age, education level, income, and even level of allegiance to green left-wing political parties on EV and solar PV uptake; using this model, the authors construct 'S-curve' technology uptake analysis based on projected changes in these socio-economic indicators over time. Other studies focus their uptake modelling on spatial influences. For example, Rodrigues et al. [208] present an autoregression approach to examine the effects of spatial interaction – including the neighbourhood effect – on EV uptake; this is paired with a logistic regression model to forecast

EV uptake into the future given these spatial influences.

Demand profiles of LCTs can be derived using one of three methods: (i) simple, fixed assumptions can be used, such as ‘assume all EV drivers plug-in at 18:00’ as in [82], [83]; (ii) data from real EV chargers or HPs can be used, usually from government-sponsored trials, as in [84]–[88]; (iii) usage data of incumbent ‘high carbon technologies’, such as ICEVs or gas-fired boilers, can be used to understand energy service demand and serve as a basis for simulation of LCT demand, as in [89]–[92].

The first method was used in the early stages of EV related literature, and has since fallen out of favour: for the EV example, while the ‘arrives in the evening, leaves in the morning’ model of driver behaviour as used in [82], [83] is a fairly common assumption in the literature, it is shown through analysis of UK NTS data by Mattioli et al. [213] that under half of UK cars are driven according to this daily commuter stereotype.

The second method does have one distinct advantage, in that it can capture the fundamentally different operation of LCTs compared with the technologies they are replacing: EV adoption has been shown to change driver behaviour [214], [215] and HP operation is fundamentally different to gas boiler operation due to their comparatively lower output temperature. However, there are two key drawbacks to using trial data. Firstly, they are inherently tied to a particular set of technologies. This is particularly clear for the EV example, as trial data can date quickly as battery sizes and charging power increase [89]. Secondly, trials are often descriptive of – or only open to – a particular subset of energy consumers. For example, in the 2021-2022 Electric Nation V2G trial, participants not only had to already own a compatible EV (and hence, by definition, be an early adopter of the technology), they also had to be homeowners with access to their own off-street parking [216].

The main advantage of the third method is that it circumvents these problems. In using consumption data from incumbent technologies to derive energy service demand, or by simulating energy service demands themselves, analyses of LCT demand can not only be made independent of particular technologies but can also encompass a wider range of energy consumer types. For example, in [89], NTS data (that naturally covers a much wider set of energy consumption behaviours than an EV trial) is used to derive potential EV charging schedules for different battery sizes, charger power levels and levels of access to charging at different locations.

Whereas research on the impacts of individual LCTs (i.e. either EVs or HPs) on distribution networks is plentiful [82]–[94], the literature on the combined effects of HPs and EVs on network infrastructure is comparatively scarce. Edmunds et al. [93] present a study on the potential for smart EV charging to maximise the available demand capacity (‘headroom’) for HP penetration in GB distribution networks. They conclude that smart EV charging could significantly increase the headroom for EVs, but only marginally increase the headroom for HPs (this is due to the significantly lower levels of flexibility assumed for heating demand than EV charging). Navarro-Espinosa et al. [94] assess the voltage and thermal impacts of these technologies for a set of LCT penetration scenarios by employing a Monte Carlo assessment technique to sample from HP and EV demand profiles, generated from heating demand data and EV trial data respectively, and randomly assign them to models of 128 UK distribution feeders. Neither of these studies use socio-economic indicators in forming their analyses, which as previously discussed, has been established as a major driver of household energy consumption and as such a key determinant in influencing the necessary network investment.

3.2.3 The Use of Socio-Economic Indicators in Modelling the Impact of LCTs on Electricity Networks

The use of socio-economic indicators to inform LCT demand profiles in distribution network models is relatively rare in the literature. Kelly et al. [90] analyse the impact of a simulated fleet of plug-in hybrid EVs on a distribution network; in doing so, disaggregation of travel behaviour via analysis of the US National Household Travel Survey is carried out to present differences in driving habits – and expected charging load – from a fleet of plug-in hybrid vehicles on the basis of age, income and location (urban/rural). Dixon and Bell [89] present a model of EV charging impact on a Scottish distribution network that uses a set of socio-economic indicators, including employment type and means of travel to work (which, as aforementioned, were found in [98] to be amongst the main drivers of household vehicle energy consumption), to assign disaggregated travel diaries and simulated charging schedules to a distribution network based on the socio-economic characteristics of the neighbourhood it serves. However, in both [89] and [90], only EVs are considered and HPs are not included. McKenna et al. [217] present a model to investigate the impact of HPs on distribution networks by developing three archetypal socio-economically differentiated neighbourhood clusters, based on analysis of UK Census data, thus linking socio-economic indicators with HP demand. However, in [217], only HPs are considered and EVs are not included. Agbonaye et al. [218] present a tool for mapping the impact of EVs, HPs and other LCTs on electricity network infrastructure. However, the analysis in [218] is carried out at the resolution of primary substations; while this is useful for high-level analysis, it misses the challenges of incorporating LCTs in distribution networks at the local level.

To the author's knowledge, there is no work in the literature that has sought to simulate the combination of EV and HP demand on distribution network infrastructure, at a higher resolution than primary substations, using socio-economic indicators to inform the application of LCT consumption data.

3.3 Mapping and Relational Analysis

This section provides a brief description of the external data used to inform place-based LCT modelling and its conditioning, it also describes the relational modelling between datasets. Outputs from the mapping and relational analysis then feed into an infrastructure assessment that consists of LCT modelling and impact quantification as highlighted in the high-level step-by-step overview of the methodology shown in Figure 3.1. The figure also highlights the industrial application of this research where the developed method is used to support engagement between different stakeholders and to inform interrelated decision-making. Mapping of the datasets and analysis was carried out in Python and the GeoPandas package [219] was used to manage all geospatial data.

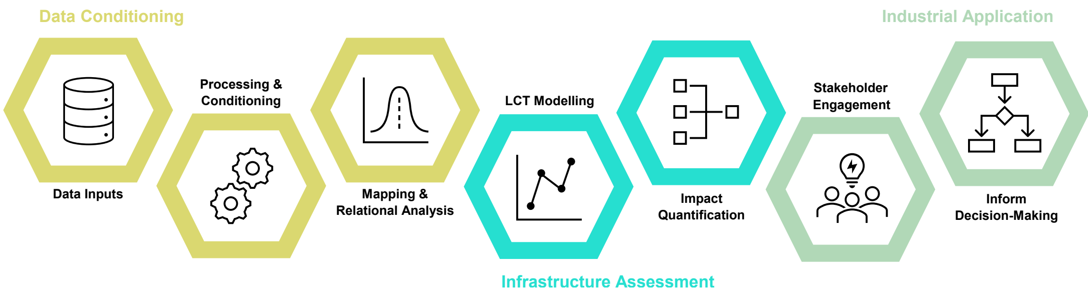


Figure 3.1. High-level step-by-step overview of the developed methodology and its application.

3.3.1 Description and Mapping of Data

The data concerned includes: distribution network GIS data, the Scottish Index of Multiple Deprivation (SIMD) published by the Scottish government [220], gas demand data published by BEIS [221], monitored HP data from the Renewable Heat Premium Payment (RHPP) scheme [222] and smart meter energy consumption data from the Low Carbon London (LCL) project [223]. These are described as follows.

3.3.1.1 Distribution Network GIS Data

A GIS captures, manages and stores data by integrating spatial information with descriptive information [224]. This allows for highly detailed spatial and relational analysis of different types of data. DNOs in GB typically record GIS data for their network assets to assist with network management and planning [225]. In support of this research, distribution network GIS data was made available to the author in the form of shapefiles, which is a geospatial vector data format developed by the Environmental Systems Research Institute [226]. This includes spatial and technical information for the entire north of Scotland[9], specifically:

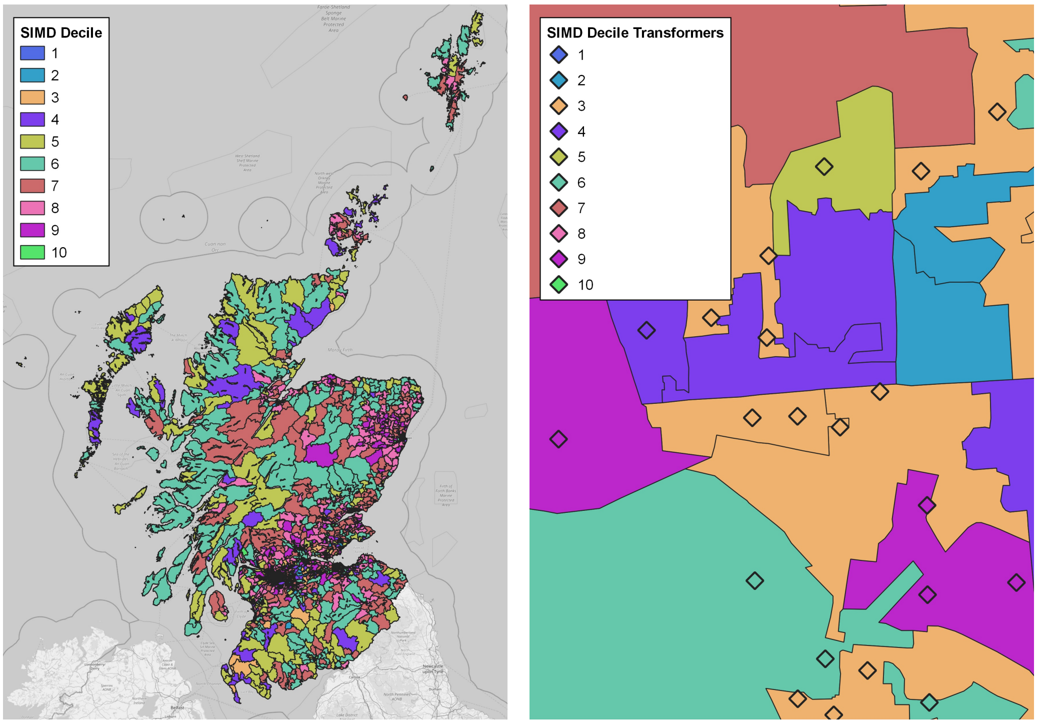
- Substations: both primary and secondary transformers.
- Cables and Overhead Lines: HV and LV underground cables and overhead lines.
- Service Locations: points where a service is provided i.e. consumer load points.
- Switching Devices: switchgear such as fuses and link boxes.

The spatial and technical information associated with their secondary transformers is of specific relevance to this chapter and although a unique GIS dataset for the north of Scotland is used, the hierarchical methodology developed could be applied to any GIS transformer dataset. There are approximately 56,000 active secondary/distribution transformers in the shapefile dataset. This is comprised of approximately 47,000 pole mounted transformers and around 9,000 ground mounted transformers. In addition to the network GIS data, external data pertaining to the ground mounted transformers is available and used to determine total connected customers and transformer rating. Due to labelling inconsistencies and dataset limitations, correlating the two datasets reduces the final number of ground mounted transformers to approximately 4,000 where sufficient information is available for the modelling concerned in this chapter.

[9]This data is not publicly available and access is only obtained by signing a non-disclosure agreement. Readers wishing to access this data should contact SSEN directly and go through the application process.

3.3.1.2 Scottish Index of Multiple Deprivation

The SIMD is the Scottish government's standard approach to identifying areas of multiple deprivation which is based on seven domains: income, employment, education, health, access to services, crime and housing [220]. It is essentially an area-based measure of relative deprivation across 6,976 small areas known as data zones that are ranked from most deprived (ranked 1) to least deprived (ranked 6,976) [220]. The 2020 SIMD geospatial data is obtained from [227] and a ranking decile of 1-10 is used to categorise the 6,976 data zones. The ranking SIMD deciles and their corresponding geospatial boundaries are used as the basis for incorporating socio-technical and socio-spatial dimensions into the analysis. The transformers are classified by SIMD decile through geospatial mapping of SIMD data zone boundaries and the GIS transformer dataset as demonstrated in Figure 3.2, where Figure 3.2a geospatially shows the SIMD boundaries across Scotland for each ranking decile and Figure 3.2b the SIMD classification of a part of the transformer GIS dataset.



(a) (b)

Figure 3.2. Mapping of SIMD and transformer GIS dataset. (a) SIMD geospatial boundaries across Scotland for each ranking decile. (b) SIMD classification of the transformer GIS dataset.

3.3.1.3 Gas Demand Data

BEIS records annual gas consumption information for every postcode in the UK [221]. This includes number of meters for each postcode, total domestic consumption (kWh) and the mean and median consumption (kWh). The mean consumption is used for this work and is obtained by averaging an annual quantity (AQ) for each meter for each postcode. The AQ is an estimate of annualised consumption for each gas meter obtained by taking two meter readings between 6 months and 18 months apart to determine the amount of gas in kWh used by a meter for one-year [228]. The dataset is only intended to consider domestic consumers and therefore excludes industrial and commercial dominated postcodes. However, it can include postcodes dominated by smaller commercial premises which only marginally fail to meet the classification threshold, such postcodes are typically outliers within the observed dataset.

The 2020 gas information is first mapped to the shapefile containing geospatial digital postcode boundaries for Scotland [229]. Through this mapping, the spatial diversity in gas demand for Scotland can be visualised as shown in Figure 3.3. However, most importantly, the digital postcode boundaries also identify which data zone each postcode corresponds to.

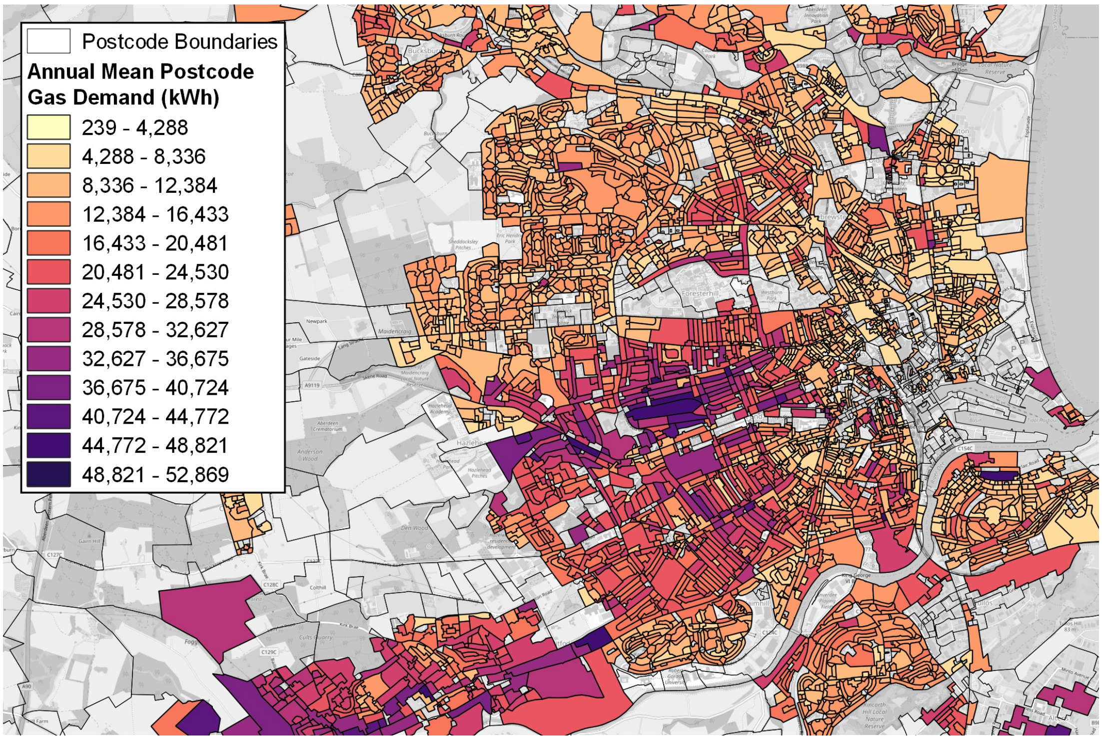


Figure 3.3. Visualisation of the spatial diversity in gas demand for each postcode in an area of Scotland.

3.3.1.4 RHPP: Monitored HP Data

The RHPP scheme provided subsidies for households and communities to install renewable heat options in residential properties [230]. An extensive monitoring campaign was carried out on 700 of these installations between October 2013 and March 2015. The output dataset contains physical monitoring data including 2-minute resolution electrical demand data, and metadata describing the features of the HP installations and the dwellings in which they were installed. A subset of this dataset [222] which contains electrical demand data for air source HPs was used for the generalised modelling approach in this work, as also used in [87]. The raw daily HP demand profiles are re-sampled from the 2-minute resolution to 30-minutes and a winter period between 01 December 2013 and 26 February 2014 is considered.

3.3.1.5 LCL: Smart Meter Energy Consumption Data

As smart meter data or transformer supervisory control and data acquisition is unavailable to the author for the areas concerned in this work, the domestic demand is modelled from smart meter data recorded during the LCL project from 2011 to 2014 [223]. The smart meter readings were taken at half hourly intervals and the consumer sample was based on the Greater London population. During the project, these consumers were classified into three categories based on CACI Acorn Group [231]; 'Affluent', 'Comfortable' and 'Adversity'. Following a similar approach as adopted in [93], more than 1,800 daily profiles for each day in a winter period between 01 December 2013 and 26 February 2014 are considered to represent a winter demand scenario. Therefore, for each CACI Acorn classification, a bank of smart meter demand profiles for a shared winter period are available for sampling.

3.3.1.6 Summary

The network GIS data is regularly updated and maintained by the DNO and both the SIMD and gas demand data are published annually by governmental bodies. The LCL smart meter data and the RHPP monitored data are the most recent publicly available monitored datasets for this demand type in the UK. Whilst society has evolved since these trials were conducted, accurately capturing the behavioural changes at the resolutions and scales concerned in this work, in terms of demand e.g. post COVID societal changes to working routines, volatility in energy prices and technological modal shifts without monitored data remains an ongoing challenge. Studies such as [232], have highlighted the challenges with representative HP demand modelling given the lack of trial data and that alternatives to using monitored data are limited by availability of household information at a granular level (to develop building physics modelling approaches that can be validated). The confidence of modelling such granularities at scale across a diverse housing stock (in consideration of occupant diversity) is also a significant limitation. As such, the datasets used are considered to be largely representative of both current domestic and HP demand behaviour. Though fundamentally, the developed methodology would be able to take any HP and smart meter monitored data as an input. Should new trial data become available, the method could be used to investigate to what extent consumer end-use demand has changed and the subsequent impact on electricity networks which could inform modelling of future demand scenarios. Additionally, for application of the method outside of the Scottish context similar socio-economic datasets and classifications as used in the SIMD should be sought by modellers. If similar datasets are unavailable, alternative methods of capturing socio-economic influences on demand would have to be considered.

3.3.2 SIMD and Demand Relationship

This section provides a breakdown of the relational modelling between the SIMD and both the LCL smart meter data and the gas demand data. First, describing how the diversity in conventional household demand is modelled with respect to the SIMD. Then exploring the relationship between the SIMD and gas consumption by describing the derivation of representative gas consumption cumulative distribution functions (CDFs) for each SIMD decile.

3.3.2.1 SIMD and LCL Domestic Demand

From the smart meter daily profiles, an average daily winter load profile for each Acorn category is obtained. Figure 3.4 compares these with the generic class 1 Elexon profile [233]. The figure shows that for the smart meter data the daily demand shape is similar between the Acorn categories. However, variation in magnitude is observed indicating that ‘Affluent’ consumers have the highest consumption and ‘Adversity’ the lowest, further confirming that socio-economic factors have an influence on household energy consumption as described in Section 3.2.1.

To account for heterogeneity in consumer demographic across the areas concerned in this work,

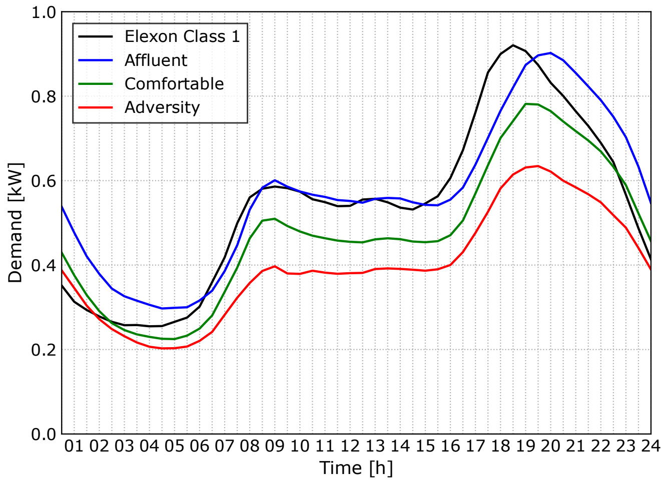


Figure 3.4. Base demand profile for each Acorn category compared with generic Elexon profile.

each transformer is classified based on its location with respect to the SIMD e.g. each transformer located in a geographic area where the SIMD is 10 would be classified accordingly. To relate the Acorn classified smart meter profiles with the SIMD classified transformers, a simple distribution alignment is considered based on the assumption that all consumers connected to a secondary transformer are of the category corresponding to the transformer's assigned SIMD decile (the average number of consumers for each secondary is typically much lower than the SIMD data zone resolution which on average contains 340 households). For transformers classified with SIMD decile 9-10, connected consumers are considered to be 'Affluent' according to the Acorn classification, 4-8 to be 'Comfortable' and 1-3 to be 'Adversity' where boundaries are defined based on parallels between the Acorn classification and SIMD.

3.3.2.2 SIMD and Gas Demand

The relationship between SIMD decile and annual mean gas demand is presented in Figure 3.5. The interquartile range method was used to clean the dataset to remove any outliers [73]. Figure 3.5a highlights that mean and variance increase with respect to SIMD decile. This suggests that although there is correlation between social deprivation and gas demand, other factors such as building characteristics e.g. building fabric, floor space and construction type also have an effect on consumption.

As the dataset includes postcodes dominated by smaller commercial premises which only marginally fail to meet the classification threshold, these can be attributed to the higher portion

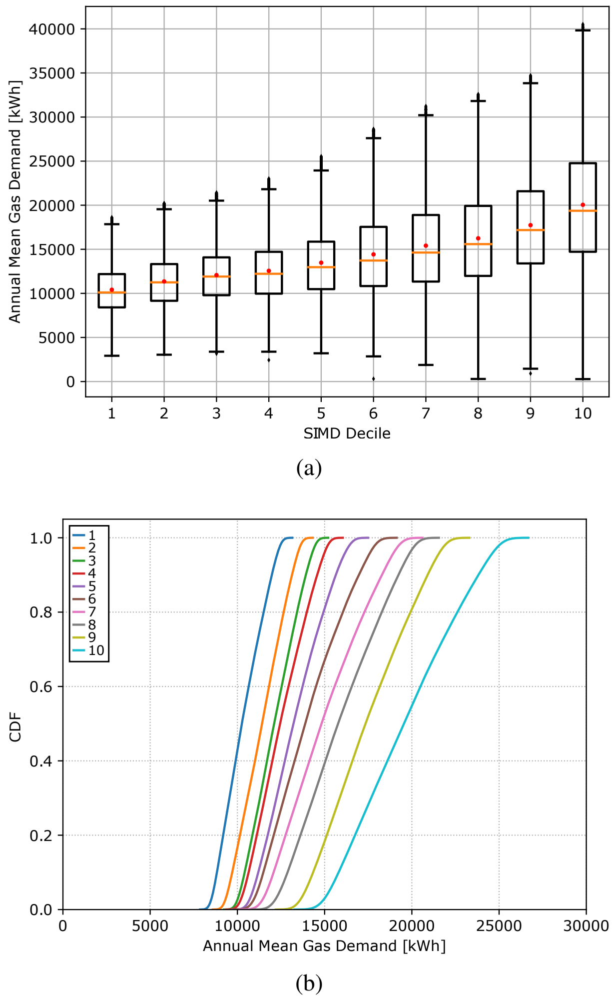


Figure 3.5. Relationship between SIMD deciles and annual mean gas demand. (a) Box plot distributions of gas demand for each decile. (b) Cumulative distribution function of central 50% gas demand for each decile.

of the gas demand spread, whereas postcodes that are comprised of both gas and other heating solutions or dominated by properties not in continuous occupation can be attributed to the lower portion. As a result, the CDFs shown in Figure 3.5b are created purely from the central 50% portion of each box plot distribution for each decile in Figure 3.5a. This is considered to be representative of typical residential household gas consumption across each of the deciles whilst accounting for variation in building stock characteristics internally within each SIMD data zone.

To summarise, a brief description of the key datasets and relational modelling between datasets has been described in this section where the datasets and relationships developed feed into the infrastructure assessment as highlighted in Figure 3.1 and in greater detail in Figure 3.6.

3.4 Transformer Assessment Methodology

This section provides a detailed description of the developed assessment methodology and the modelling techniques used to underpin the approach. This includes details on both HP and EV modelling and the mechanism used to evaluate the results.

3.4.1 Methodology Overview

The methodology is adaptable subject to the assessment scenario under consideration. This work considers four scenarios: the uptake of HPs in isolation modelled by using the generalised RHPP trial data method, the uptake of HPs in isolation modelled by using the localised method which accounts for social dimensions, the uptake of EVs in isolation and the combined uptake of both EVs and HPs (using the localised HP modelling method). A high-level flowchart of the developed methodology for the combined assessment scenario is presented in Figure 3.6, a larger figure for the images not shown elsewhere in the text can be found in Appendix A. The flowchart demonstrates how mapping of external data is used to support relational analysis which feeds into socio-technical and socio-spatial LCT modelling and then into infrastructure assessment. A Monte Carlo assessment technique is used with multiple iterations to account for variations in the distribution of gas demand according to the CDFs for each SIMD decile, HP usage profiles and EV charging profiles as similarly used in [94]. Algorithm 1 (shown below) provides a summary of the iterative process for the combined scenario. For the HP only scenarios steps 9-11 in Algorithm 1 are excluded and for the EV only scenario steps 6-8 are excluded. For the generalised HP modelling approach scenario, step 7 is replaced with the raw re-sampled daily HP profiles which are stochastically sampled according to HP penetration levels.

3.4.2 Localised Heat Pump Modelling

A household's electrical demand is directly proportional to its heat demand [232]. In turn, domestic heat demand is a complex interdependent function of several components combining building physical parameters as well as the behavioural habits of the occupants. This complexity is further compounded by the specific HP parameters of a household, such as power rating,

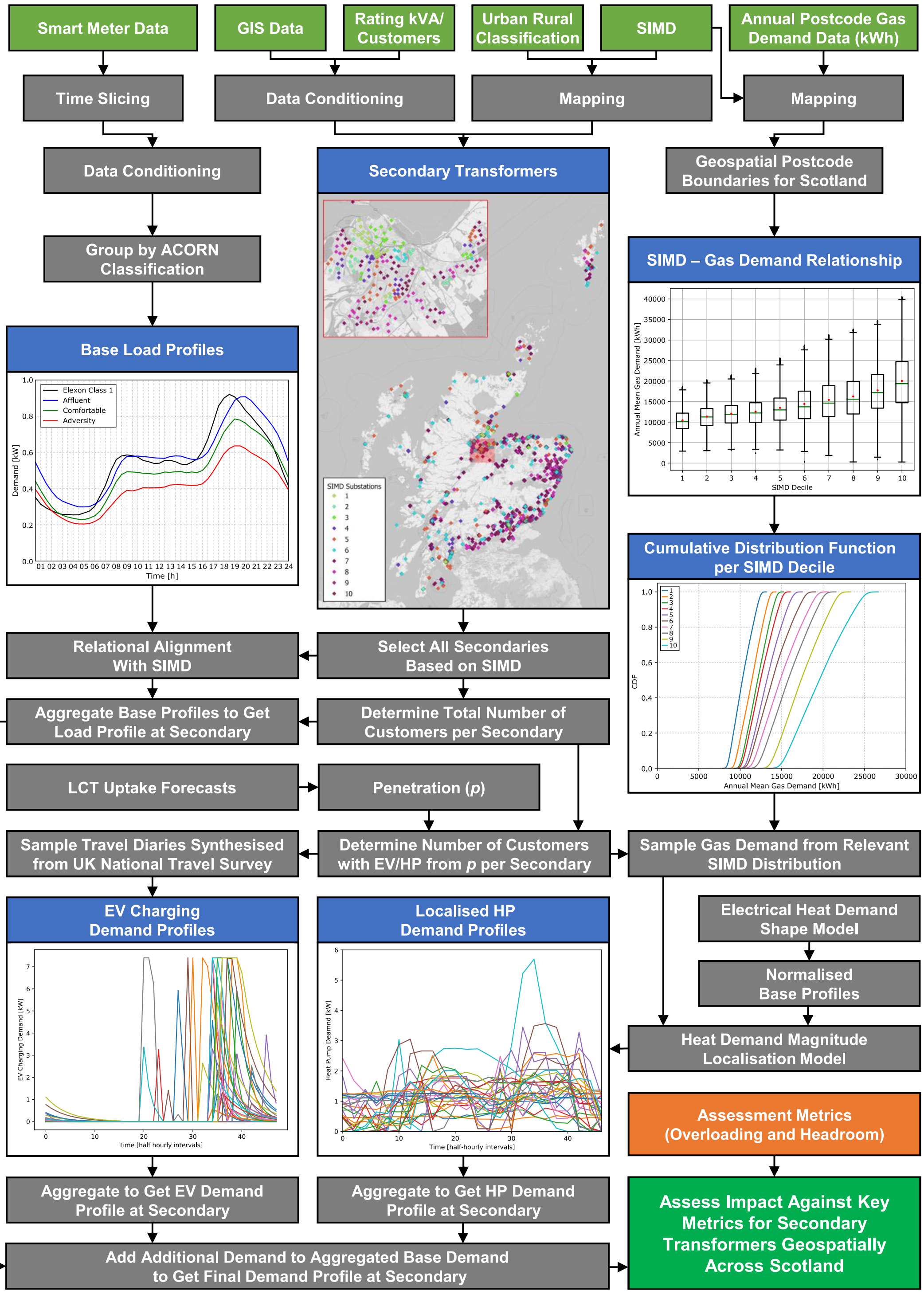


Figure 3.6. High-level representation of the developed assessment methodology.

Algorithm 1 Monte Carlo Assessment Approach

for $si \in SIMD$ **do**
    for $T \in Transformers$ **do**
        Use (3.5) to calculate P_{dem}
        for $p \in Penetrations$ **do**
            while $i < 100$ **do**
                Use (3.6) to calculate C^{HP}
                Use method in Figure 3.7 and (3.1)–(3.4) to create localised socio-technical electrical heat demand profiles based on si then sample according to C^{HP}
                Use (3.7) to calculate P^{HP}_{dem}
                Use (3.8) to calculate C^{EV}
                Sample EV charging diaries based on C^{EV}
                Use (3.9) to calculate P^{EV}_{dem}
                Use (3.10) to calculate daily headroom h
                Store h for every iteration
                $i = i + 1$
            end while
            return average of h for each p
        end for
    end for
end for

heat source, and efficiency [232], as this governs the relationship between heat output and electrical demand. However, due to the interdependency of multiple components the full extent of combined localised influences is currently still largely unknown [73]. This in part, is due to a lack of high-resolution datasets that can be used to validate and support the development of data-driven and built environment physics-based modelling. Therefore, sufficiently granular technical information is limited, particularly in the public domain and as a result, reliance is often placed on Census type data which has its own limitations. Nevertheless, the core issue of incorporating localisation into the methodology by translating building and behavioural parameters into a direct or electrical heat demand that can be validated remains.

Note that whilst some commercial and industrial heat loads may be decarbonised via electrification e.g. industrial sized HPs or district heating/heat networks. They may also follow alternative pathways e.g. use of hydrogen, and other evolving technologies in this space. As this work is focused at the secondary transformer resolution (by extension the LV level) and primarily on space heating demand (the amount of heat required to heat a building and to maintain a particular heating profile), modelling of ‘large’ commercial and industrial demand is excluded as it is considered that the bulk of this heating demand, at least in GB, will be connected above the secondary transformers i.e. at 11/6.6 kV and above. There may be scope in future work to include small-scale commercial and industrial HP demand, though at the time of writing no trials have been conducted yet to obtain monitored data in the UK for these premises.

For the studies considered in this chapter, in the absence of sufficiently granular technical information surrounding household physical and behavioural parameters, two established approaches of converting gas demand to equivalent electrical heat demand are employed, the *Heat Demand Magnitude Localisation Model* and the *Electrical Heat Demand Shape Model* developed in [232]. These are combined to construct locally sensitive half-hourly electrical heat demand profiles where the developed relationships between gas demand and social deprivation are used as inputs to the modelling. A summary of the combined modelling approach is outlined by Figure 3.7 and a brief description of each model component is provided as follows.

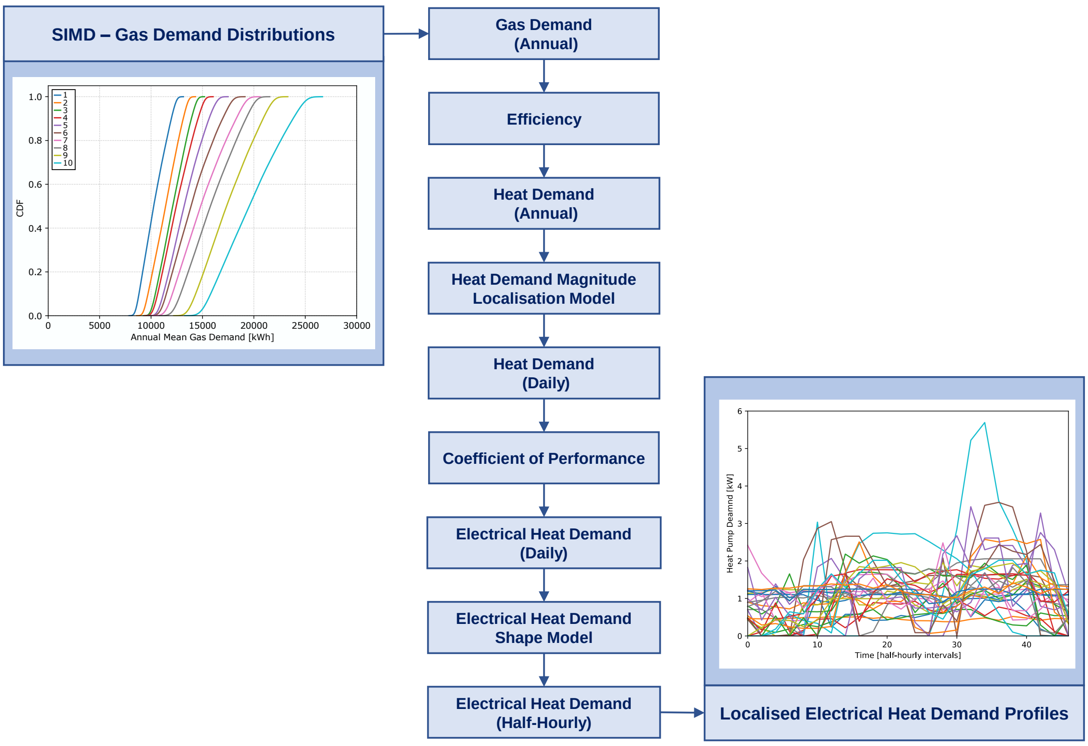


Figure 3.7. Methodology used to convert annual gas demand from CDFs to localised electrical heat demand profiles.

3.4.2.1 Heat Demand Magnitude Localisation Model

The *Heat Demand Magnitude Localisation Model* is used to transform the CDF sampled gas demand into a daily demand magnitude that is proportionally scaled to local physical and behavioural components that influence heat demand. This gas demand serves as a proxy for local building, climate and behavioural parameters. Firstly, a gas conversion efficiency (η) is used to transform the raw annual gas demand (D_G^{annual}) into an equivalent annual direct heat demand (D_H^{annual}) as shown in (3.1). For this work, a fixed gas boiler efficiency of 80% has been used. This has been obtained by taking an average of over 2,000 different mains gas boiler models with efficiencies ranging from 55% to 90.3%. The recorded efficiencies are based on the Seasonal Efficiency of Domestic Boilers in the UK rating scheme and are stored in a database that is used to support UK building energy performance assessments [234]. D_H^{annual} is then converted into a daily heat demand (D_H^{daily}) through (3.2) and (3.3) by assuming that heat demand varies sinusoidally throughout the year in accordance with seasonal temperature variation, D_H^{annual} provides the area under the sinusoid which defines the amplitude and offset parameters and subsequently the daily demand variation throughout the year and x corresponds to day of year.

$$D_H^{annual} = \frac{D_G^{annual}}{\eta} \tag{3.1}$$

$$D_H^{annual} = \int f(x)\,dx = \int_0^{365} D_{amp} \times \sin(\frac{2\pi}{365}x + \phi) + D_{off}\,dx \tag{3.2}$$

$$D_H^{daily} = f(x) = D_{amp} \times \sin\left(\frac{2\pi}{365}x + \phi\right) + D_{off} \tag{3.3}$$

$$D_E^{daily} = \frac{D_H^{daily}}{COP} \tag{3.4}$$

The default amplitude (D_{amp}) and offset (D_{off}) parameters have been applied. These fit parameters were tested versus monitored gas meter data collected at 30-minute intervals for several thousands of customers in 2010 as part of the Energy Demand Research Project [235] and monitored HP heat and electrical demand data obtained from the RHPP dataset [222]. The daily heat demand is transformed into a daily electrical demand (D_E^{daily}) via a COP through (3.4). From the RHPP dataset HP COP typically ranges from 2 to 4 [222] which is comparable to the HP COPs presented in [118]. A fixed COP of 3 is used for the studies considered in this work.

3.4.2.2 Electrical Heat Demand Shape Model

The *Electrical Heat Demand Shape Model* developed in [232] is then used to transform the daily electrical demand into a set of half-hourly demand figures sensitive to local temperature conditions. The modelling approach incorporates monitored HP data from the RHPP dataset and is validated against operational demand data collected during the LCL HP trials [236].

In [232], Figure 3.8 is presented which highlights the RHPP HP hourly duty cycle distribution (0 to 24 hours, x-axis) versus average duty cycle (y-axis) for 0°C, 5°C, 7°C, 10°C, 15°C and 20°C. From this, clear morning and evening peaks are visible, but there are also customers with very high and very low HP activity at either extreme. Furthermore, Figure 3.8 clearly shows the reduction in HP activity with temperature increase where the method used to derive the average duty cycle (δav) and hourly duty cycle (δh) is also described in [232].

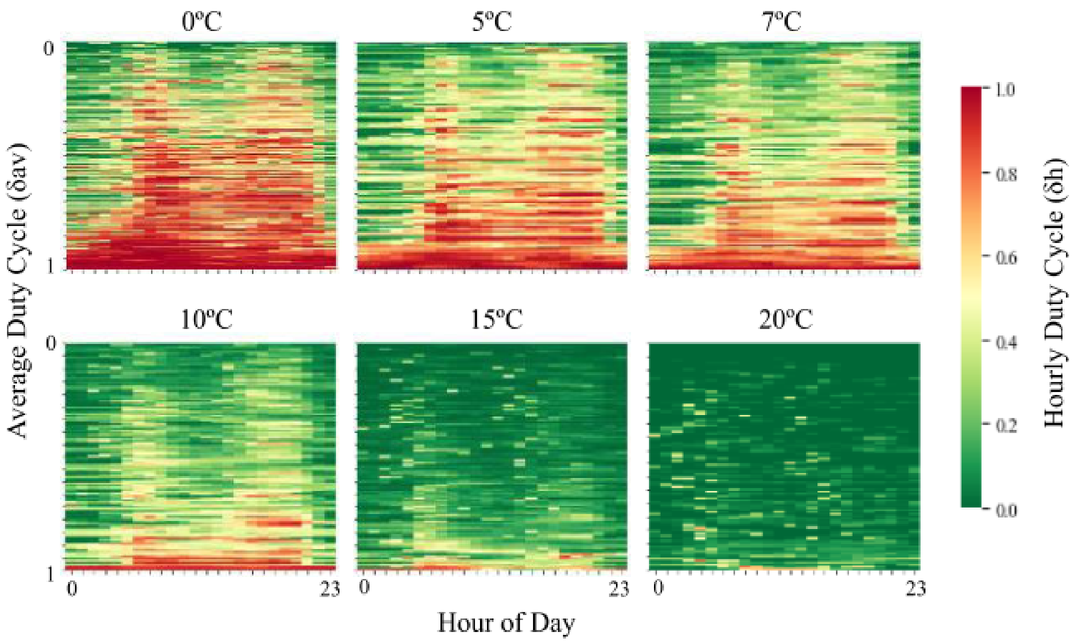


Figure 3.8. RHPP HP hourly duty cycle distribution (0 to 24 hours, x-axis) versus average duty cycle (y-axis) for 0°C, 5°C, 7°C, 10°C, 15°C and 20°C [232].

With this, it is evident that there are common recurring electrical heat demand profiles that repeat within the RHPP dataset under specific temperatures, despite the disparate geographical and demographic conditions. For this work, these have been normalised for an ambient temperature of 0°C which is used to simulate winter cold conditions[10]. The normalised profiles are then used as the basis for HP daily load shape forming and are sampled accordingly.

3.4.3 Electric Vehicle Modelling

In addition to traditional power rating and capacity challenges, a significantly challenging aspect of EV modelling is the uncertainty surrounding consumer behaviour. External factors are expected to influence consumer travel routines and consequently EV charging patterns. In this work, residential EV charging schedules synthesised from the UK NTS [237] are used to capture elements of the significant variation in energy demand for car usage across society. This method was previously developed in [192], [193] and used in other works including [93].

EV modelling in this work follows the government-led assumption that the majority of charging in the UK will take place at home [202]. From the perspective of the DNO, modelling at-home charging only is more conservative, as it is reasonable to expect they will have to deal with scenarios where all vehicle chargers in a given area are home-chargers rather than other chargers or a combination of (particularly in purely residential areas where HPs are more likely to be installed). Also, it is considered that fast charging stations or charging hubs are more likely to attract specific attention and study from DNOs and would typically fall within the remit of the local authority planning system. Therefore, there would be scope for DNOs to anticipate their connection and to influence their location to ensure compatibility with network capacity.

As in [193], EV modelling considers routine charging schedules to be the primary charging scenario. These charging schedules consider the principle of 'least inconvenience' to the consumer where charging behaviour has become routine and reflective of social behaviour. EVs are connected when consumers arrive at their households irrespective of the vehicle's state of charge seeking the maximum feasible state of charge gain during the parked duration and by the charging constraints. These charging patterns are essentially 'dumb' in that there is no incentivisation for scheduling or optimisation that facilitates demand side management. In ad-

[10]Due to the limited availability of data for the operating region below 0°C in existing monitored datasets the model cannot reliably capture the effects of HP demand below 0°C. Furthermore, as conversion efficiency is reduced in-line with a reduction in the COP in this operating region it would not be uncommon for secondary resistive heating to be installed to support HP output during colder conditions. This could further increase temperature dependent electrified heating demand and would require additional modelling to capture the demand characteristics of this behaviour.

dition, this work assumes all households have the necessary EV charging infrastructure at each residence and assumes that a maximum of one EV can be charged at each residence at any given interval. A set of 10,000 winter weekday charging schedules have been derived with a fixed 7.4 kW rating (high power 'fast' home charging, typically a single phase 32 A, 230 V connection) across a range of 'typical' vehicle battery sizes: 24, 30, 40, 60 and 75 kWh. An inverter efficiency of 88% [238] has been used for the heuristic which is further described in [192], [193].

3.4.4 Transformer Headroom

Transformer headroom is one of the key indicators as to when DNO intervention may be necessary. Headroom relates to the remaining capacity after the downstream demand has been met. As in [93], headroom is used analogous to hosting capacity.

Despite any initial oversizing of transformers in network planning, the demand growth associated with the uptake of LCTs is expected to significantly erode existing headroom. Across the distribution network this may lead to overloading and eventual degradation of assets as they operate closer to their physical limits.

To determine the daily headroom profile for each individual transformer, the aggregated demand, $P_{dem,t}$ at time t, where $t = 1, 2, 3, \ldots, 48$ for all consumers ($i = 1, 2, 3, \ldots, TC$, where TC is the total number of consumers), is first calculated as follows:

$$P_{dem,t} = \sum_{i=1}^{TC} lp_{i,t} \tag{3.5}$$

where $lp_{i,t}$ is the measurement of the i^{th} consumer load profile at the t^{th} interval. The aggregated HP demand, $P^{HP}_{dem,t}$, at the t^{th} interval, is then calculated as follows:

$$C^{HP} = TC \times HP_{pen} \tag{3.6}$$

$$P^{HP}_{dem,t} = \sum_{i=1}^{C^{HP}} HP_{i,t} \tag{3.7}$$

where C^{HP} is the number of customers with a HP based on TC, HP_{pen} is the HP penetration percentage and $HP_{i,t}$ is the measurement of the i^{th} HP profile at the t^{th} interval. The aggregated

EV demand $P^{EV}_{dem,t}$, at the t^{th} interval, is similarly calculated:

$$C^{EV} = TC \times EV_{pen} \tag{3.8}$$

$$P^{EV}_{dem,t} = \sum_{i=1}^{C^{EV}} EV_{i,t} \tag{3.9}$$

where C^{EV} is the number of customers with an EV based on TC, EV_{pen} is the EV penetration percentage and $EV_{i,t}$ is the measurement of the i^{th} EV profile at the t^{th} interval. The headroom, h_t, at the t^{th} interval, is then obtained from:

$$h_t = \frac{P_{max} - (P_{dem,t} + P^{HP}_{dem,t} + P^{EV}_{dem,t})}{P_{max}} \times 100 \tag{3.10}$$

where P_{max} is the transformer rating.

To visualise the results geospatially the daily headroom is split into four bands as shown in Figure 3.9. These bands are based on the constraints in (3.11) and are primarily used to determine the priority state of the transformer.

$$h_x = \begin{cases} L, & h_t \geq 75 \\ M, & 75 > h_t \geq 50 \\ H, & 50 > h_t \geq 25 \\ C, & 25 > h_t \end{cases} \tag{3.11}$$

where h_x is a set containing the priority classification of h_t, L is Low-priority, M is Medium-priority, H is High-priority and C is Critical-priority. The final priority state S is that in which the transformer spends most time over the 48 daily time periods. For example, in Figure 3.9, for the localised approach, as the transformer spends the most time in $75 > h_t \geq 50$, the transformer's S would be Medium-priority. For the generalised approach, as the transformer spends the most time in $50 > h_t \geq 25$, the transformer's S would be High-priority. This provides a means of classifying all transformers in terms of their criticality with respect to the urgency of a network management intervention.

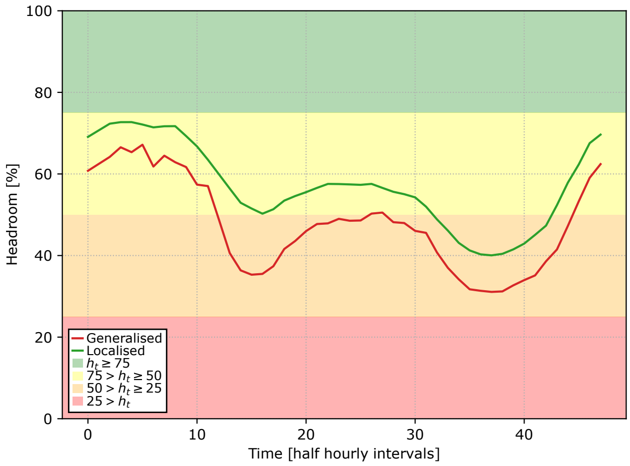


Figure 3.9. Example of daily headroom profiles for both the localised and generalised HP modelling approaches with associated constraint banding.

3.5 Results and Analysis

The results section is split into two subsections; firstly, a comparative analysis between the localised socio-technical approach to HP modelling and the generalised RHPP approach is presented. Then EVs are introduced, independently and in combination with the localised HP modelling approach which enables combinational LCT impact assessment analysis.

3.5.1 Comparative Analysis between Localised Socio-Technical and Generalised HP Modelling

To determine the spread of social deprivation impact, analysis is focused on transformers classified by SIMD deciles 1, 5 and 10. A subset of the transformers are used to demonstrate the impacts of both the localised and generalised HP modelling approaches. The subset and examples presented are selected to capture variation in both transformer rating and the number of connected consumers to provide an indication of the expected variance and impact across the asset base. A larger subset is then used to support geospatial analysis which demonstrates scalability of the methodology. The larger subset is also selected to allow for cross-comparison between areas with differing levels of social deprivation.

Figure 3.10 provides the daily headroom profile of two different transformers at multiple HP penetrations (25%/50%/75%/100%) for SIMD decile 1. Figure 3.11 and Figure 3.12 show the

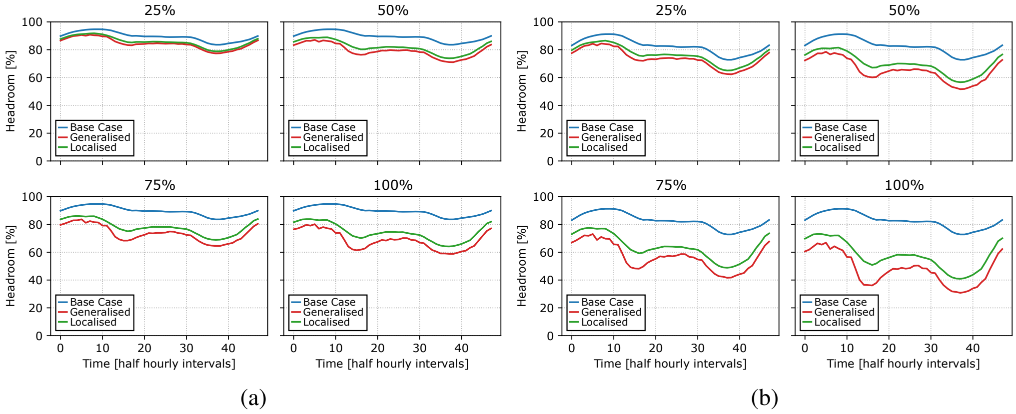


Figure 3.10. Daily transformer headroom at different penetrations for SIMD decile 1. (a) Example 1. (b) Example 2.

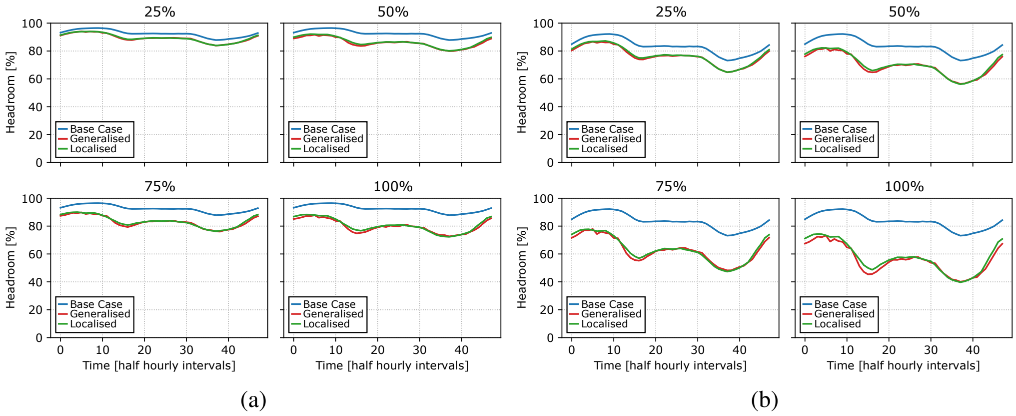


Figure 3.11. Daily transformer headroom at different penetrations for SIMD decile 5. (a) Example 1. (b) Example 2.

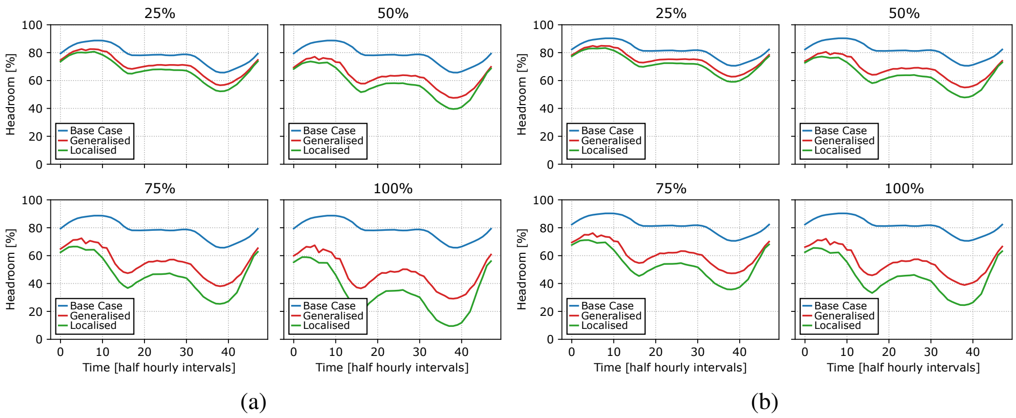


Figure 3.12. Daily transformer headroom at different penetrations for SIMD decile 10. (a) Example 1. (b) Example 2.

profiles for SIMD deciles 5 and 10, respectively. From the two examples provided in Figure 3.10, the headroom for the socio-technical localised HP modelling approach varies compared with the generalised approach. Variation is also observed in Figure 3.12. In Figure 3.11 the headroom under both approaches is similar with marginal variation. The figures highlight that the generalised model tends to over-estimate headroom in the most socially deprived areas and to under-estimate it in the least socially deprived. This infers that the localised model provides an improved assessment of the true headroom in comparison with the generalised approach. Note that although daily HP demand profile shape is sensitive to temperature variation [232], as a winter scenario is considered for both approaches, the impact of temperature variation is negated and due to the numbers of consumers concerned, diversity in consumer behaviour is also negated [87]. This explains why similar daily headroom shapes are observed for both approaches. It is considered that with the variation in magnitude observed the similar-but-scaled curves are sufficiently modelling local diversity for the purpose of this study.

Figure 3.13 further demonstrates this by highlighting the daily transformer headroom for multiple different transformers at 100% penetration each with related SIMD deciles 1, 5 and 10, respectively. Figure 3.13 also confirms that headroom is highly dependent on transformer rating and number of connected customers. More importantly, Figure 3.13c specifically highlights that in taking a generalised approach to modelling HP demand, in certain instances, the headroom would be under-estimated to the extent that it fails to capture an overloading scenario that would otherwise be identified by taking a localised HP modelling approach. Conversely, in Figure 3.13a, by taking a generalised approach, a network management intervention may be triggered before necessary due to an overestimation of the headroom. Figure 3.13 highlights that inaccurate estimation of headroom does not apply for all transformers and as such, the proposed classification method allows for prioritisation in terms of their criticality. In general terms, the localised HP modelling approach can capture generic demand variation. However, by directly linking demand to socio-technical characteristics, the headroom can be better quantified with respect to socio-spatial diversity.

The variation in headroom at each transformer as demonstrated in Figure 3.13 is geospatially represented in both Figure 3.14 and Figure 3.15. A geospatial snapshot of daily transformer headroom at the four levels of HP penetration studied using the generalised HP modelling approach and constraint bands is presented in Figure 3.14. The figure demonstrates the spatial diversity in secondary transformer headroom across a region in Scotland encapsulating a portion of the 4,000 transformers considered. The figure provides a visualisation of the impact HP uptake has on transformer headroom in different areas of network. The available headroom noticeably declines as HP penetrations are increased. Figure 3.15 presents a snapshot of the same area using the localised HP modelling approach and constraint bands. The impact of the localised approach in comparison with the generalised is visually evident.

Figure 3.16 and Figure 3.17 show the effect of localised modelling in relation to relative affluence. Figure 3.16 provides an area snapshot with emphasis specifically on areas with lower social deprivation (SIMD deciles 9 and 10). The figure compares the generalised approach (top) with the localised approach (bottom). As these areas have lower social deprivation, HP demand is likely to have a greater impact on headroom in these regions. Figure 3.17 provides an

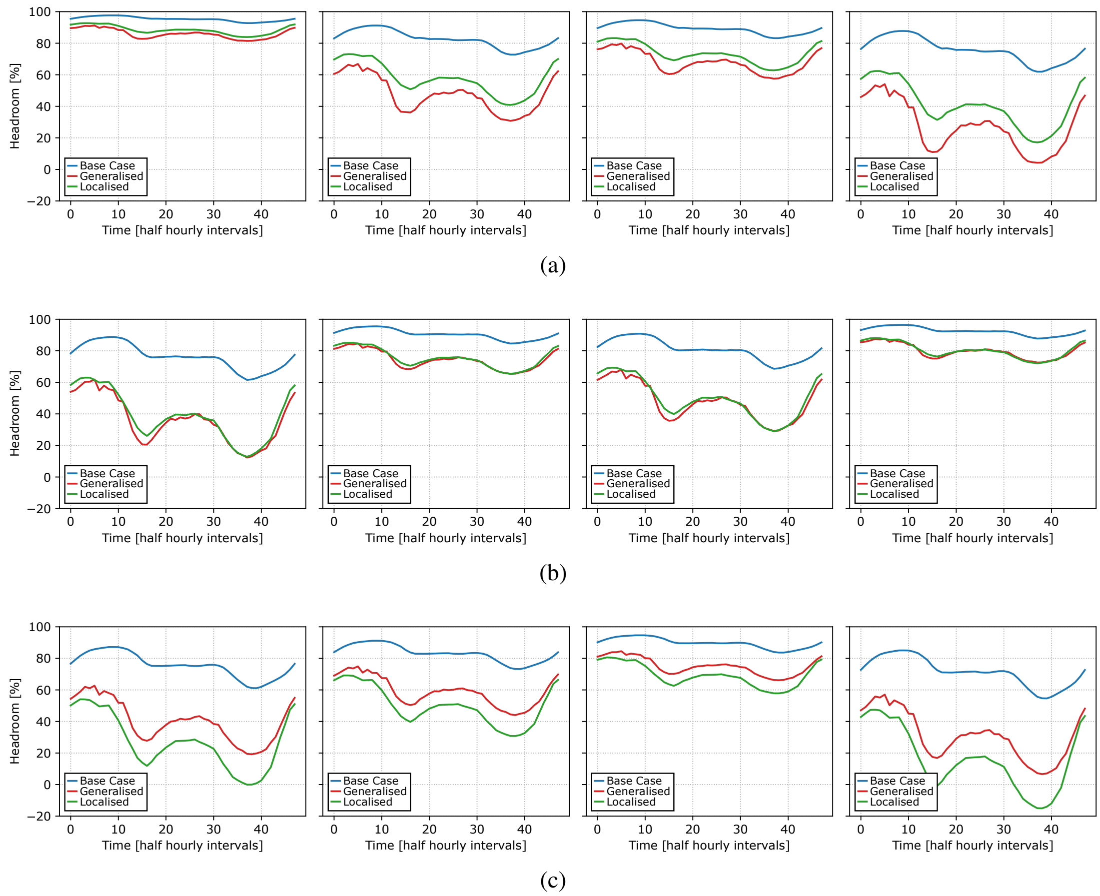


Figure 3.13. Daily transformer headroom for multiple different transformers at 100% penetration. (a) SIMD 1. (b) SIMD 5. (c) SIMD 10.

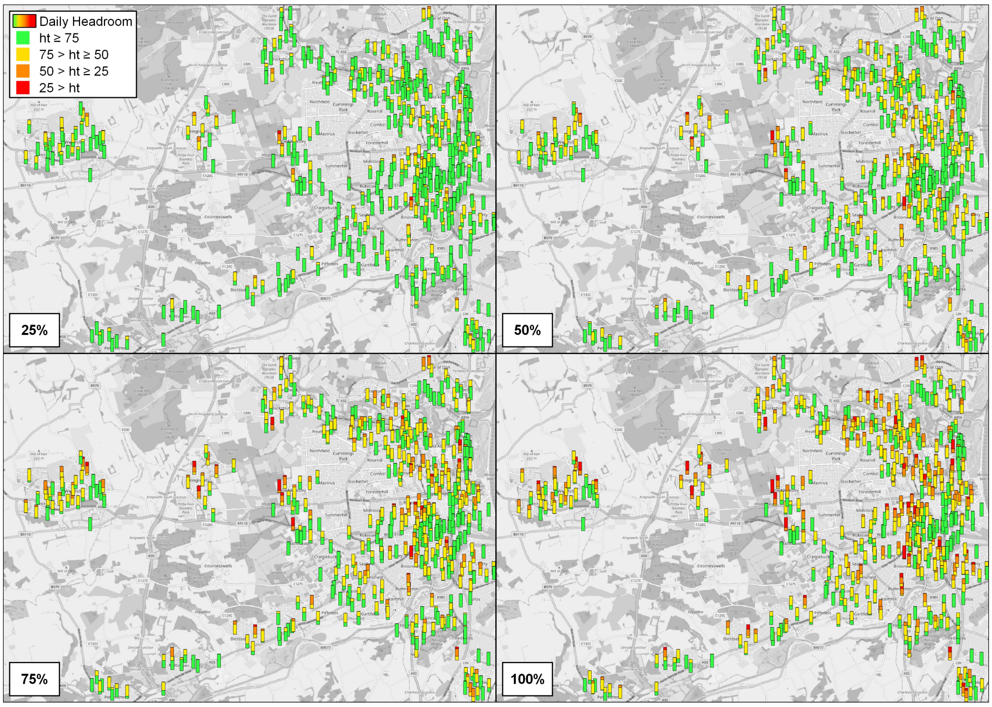


Figure 3.14. Visualisation of daily transformer headroom for each HP penetration simulated using the generalised HP modelling approach and constraint bands.

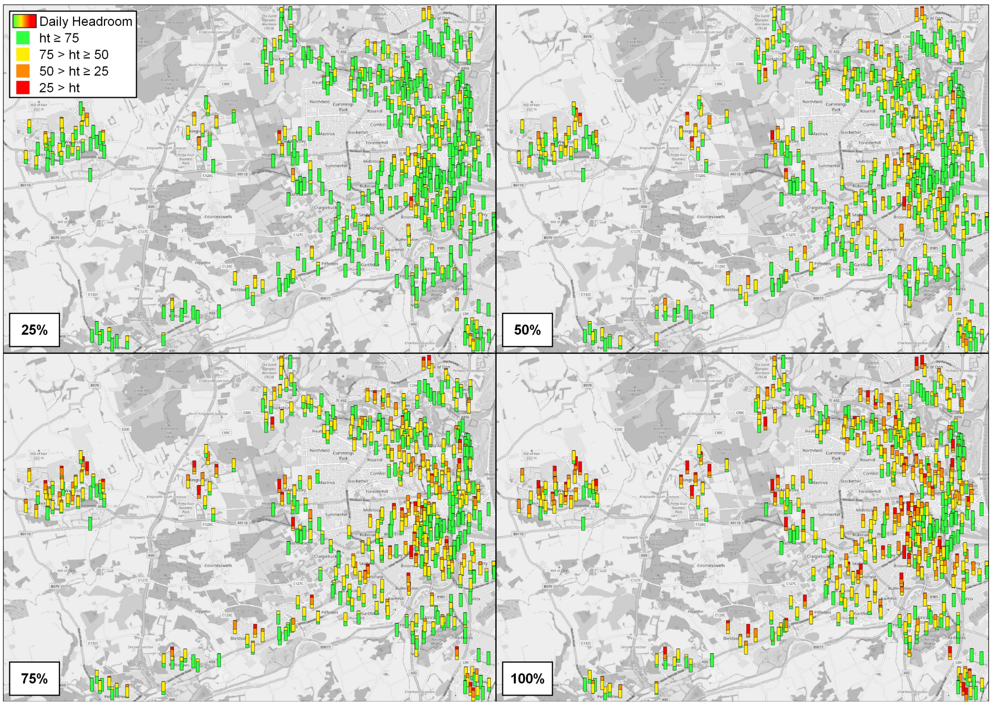


Figure 3.15. Visualisation of daily transformer headroom for each HP penetration simulated using the localised HP modelling approach and constraint bands.

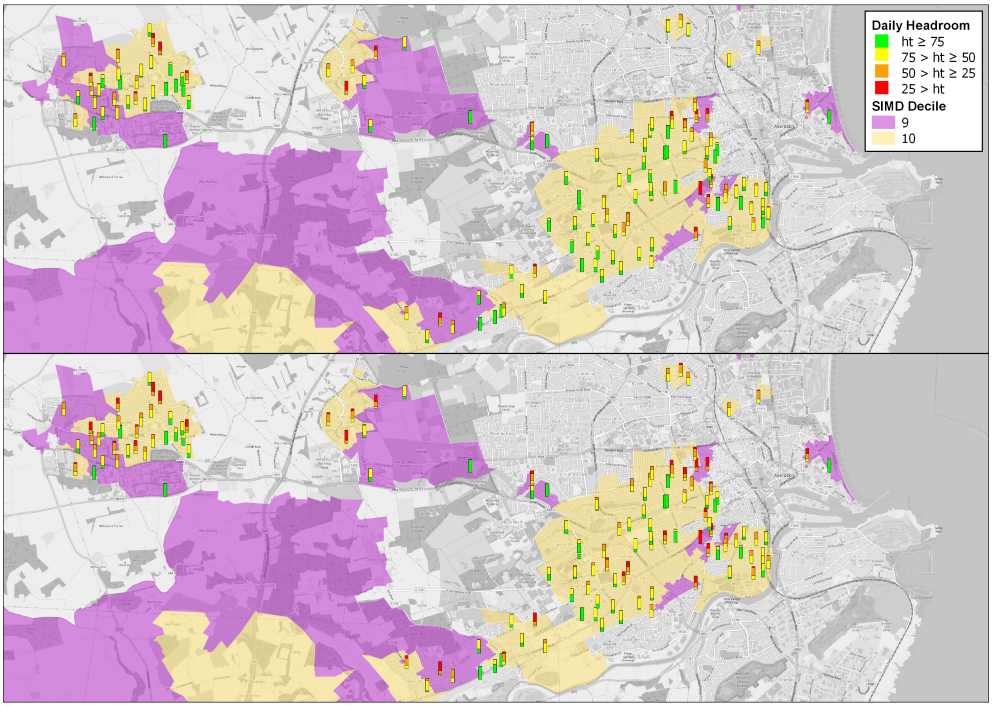
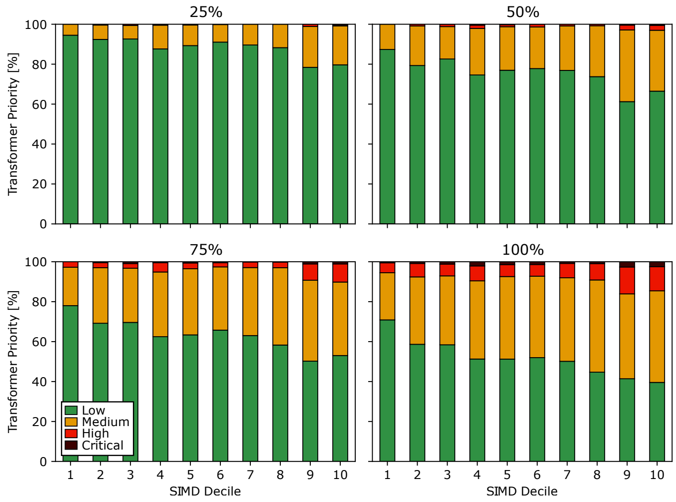
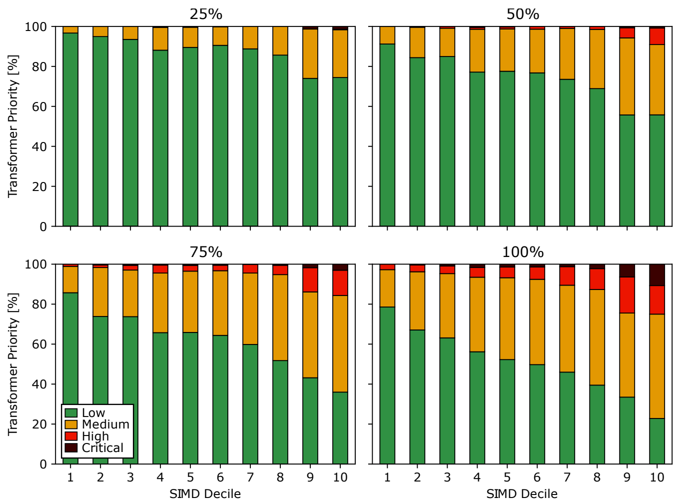


Figure 3.16. Comparison of the generalised and localised approaches in less socially deprived areas (SIMD deciles 9 and 10) at 100% HP penetration. (top) Generalised. (bottom) Localised.

Figure 3.17. Comparison of the generalised and localised approaches in more socially deprived areas (SIMD deciles 1, 2 and 3) at 100% HP penetration. (top) Generalised. (bottom) Localised.



(a)



(b)

Figure 3.18. Transformer intervention priority for each SIMD decile comparing the generalised and localised approaches. (a) Generalised. (b) Localised.

area snapshot with emphasis specifically on areas that have higher social deprivation in terms of SIMD (deciles 1, 2 and 3). The opposite effect can be observed, where the impact of HP uptake is less prominent for the localised modelling approach compared with the generalised (as also demonstrated in the presented examples in both Figure 3.10 and Figure 3.13a).

Using the classification defined by (3.11), each transformer is classified in terms of S as determined by the modelled daily headroom scenario. Figure 3.18a and Figure 3.18b compare transformer intervention priority for each SIMD decile and modelling approach, respectively.

In Figure 3.18a, the proportion of High-priority transformers, particularly for 100% HP penetration, are relatively consistent across the SIMD deciles with only minor variation. However, in Figure 3.18b there is a trending increase from decile 1 to 10 and a reduction in the number of transformers classified as Low-priority is observed. This reduction trend is present but less pronounced in Figure 3.18a. This is likely a consequence of the variation in domestic demand from the diversified base load profiles shown in Figure 3.4. In general terms, the figures broadly emphasise the impact socio-technical and socio-spatial diversity may have in influencing network decision-making. They highlight that failing to consider socio-technical and socio-spatial diversity may lead to an over/under-estimate of transformer headroom in different locations which may feed into reinforcement and flexibility planning. This confirms the need for consideration of socio-economic indicators in the decision-making process. It is also noted that this diversity may have an impact on rate of LCT uptake which has the potential to influence decision-making further.

To summarise, the impact of socio-technical and social-spatial diversity on daily transformer headroom has been demonstrated on a subset of the transformer dataset. The subset and examples presented are selected to capture variation in both transformer rating and the number of connected consumers; to provide an indication of the expected variance and impact across the asset base. The larger subset is used to support geospatial analysis which demonstrates scalability of the methodology and allows for cross-comparison between areas with differing levels of social deprivation. In Figure 3.18, the entire asset base of 4,000 ground mounted transformers (45% of the total fleet dataset) is considered. The results presented confirm that a generalised approach can over/under estimate headroom and feed into network planning decision-making subsequently triggering a network management intervention before/after it is necessary. However, the localised HP modelling approach that includes linked socio-technical modelling allows for enhanced representation of HP demand, and in turn, transformer headroom quantification in the presence of socio-spatial diversity.

3.5.2 LCT Assessment

In this section the combined impact of electrified heat and transport is investigated. Both HPs and EVs are initially considered independently, then they are integrated, as shown in Figure 3.6, to assess the cumulative impact. Figure 3.19 shows the average daily transformer headroom for the localised HPs only, EVs only and combined scenarios for two transformers with multiple penetrations of each (0%/25%/50%/75%/100%). It is noted that HP and EV uptake are assumed to be the same here, though the developed methodology can account for independent variation. As previously, the transformers have been selected to highlight the general impact of LCT uptake on the daily headroom profile shape and magnitude. The figure highlights that for both transformers under the HP only scenario there is a noticeable reduction in headroom in the early morning and early evening. This can be attributed to space heating requirements which generally align with standard daily social rhythms. As penetrations increase, the headroom is significantly reduced, although the extent varies between the examples presented. In the EV only scenario, a noticeable evening peak can be observed, this is a consequence of the 'least inconvenience' consumer charging behaviour as described in Section 3.4.3. Both scenarios in isolation have remaining headroom at 100% penetration. However, in the combined scenario for both cases, when penetrations exceed 75%, the headroom becomes negative during the evening peak which indicates that overloading has occurred. In the combined scenario, due to HP early morning demand and combined HP/EV evening demand, the daily headroom is significantly reduced across the day which may have negative consequences for their long-term health and serviceability [75]. Figure 3.20 presents the geospatial visualisation of daily transformer headroom for the combined HP and EV uptake scenario based on the defined constraint bands. In comparison with the HP only scenario using the localised modelling approach shown in Figure 3.15, the headroom is significantly more challenged across the asset base, particularly at higher penetrations.

This analysis emphasises the extent of the cumulative challenge with both the decarbonisation of heat and transport via electrification. The combination of both HPs and EVs, and the change in headroom indicates that demand side management techniques such as peak shaving through EV charge scheduling must consider the mix of LCTs and their relative demand.

3.6 Discussion

The discussion presented in this section takes a wider contextual view of the described findings and considers the broader implications. The value of the developed methodology is also established with respect to key parties that are actively involved in the energy transition.

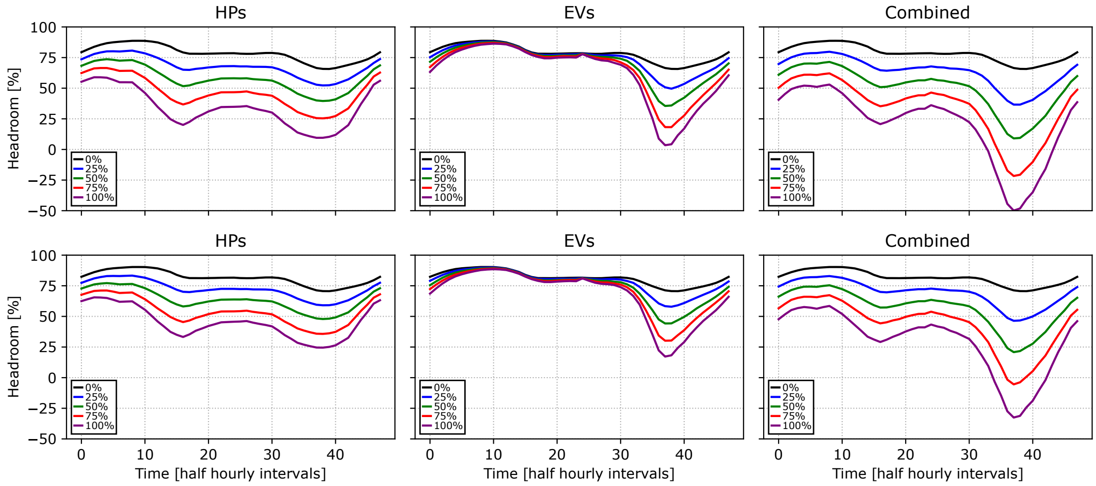


Figure 3.19. Average daily transformer headroom for HP, EV and combined uptake scenarios for each penetration. (top) Example 1. (bottom) Example 2.

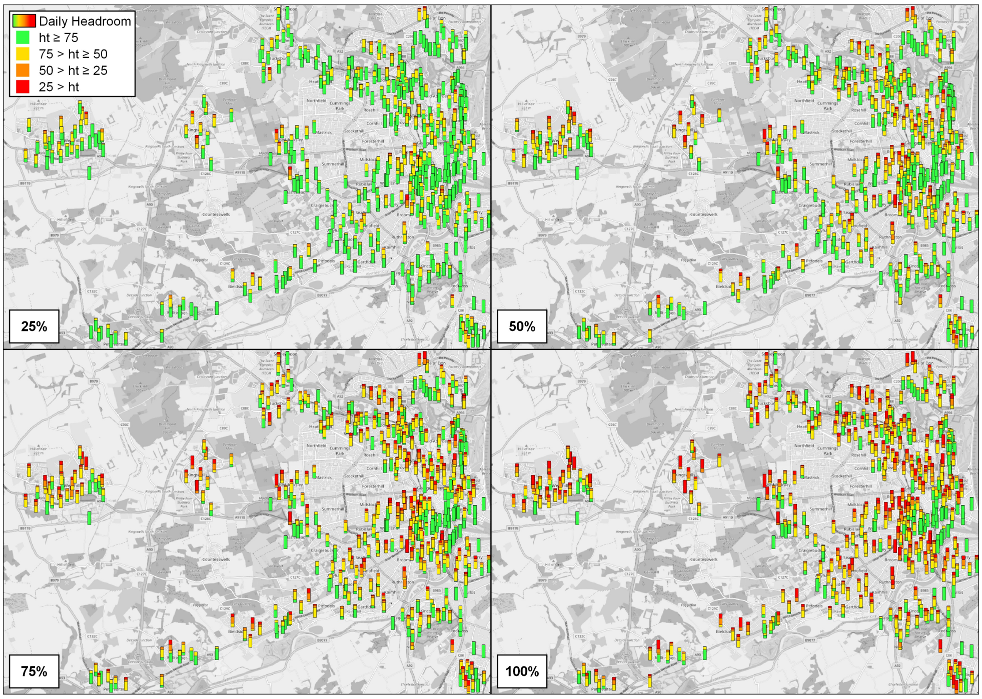


Figure 3.20. Visualisation of daily transformer headroom for each penetration for combined HP and EV uptake based on the constraint bands.

3.6.1 Distribution Network Operators

The developed methodology allows for broad infrastructure assessments at a local level whilst accounting for socio-technical and socio-spatial diversity. This is highly attractive for DNOs due to the high uncertainty associated with LCT uptake and impact across different regions [191]. Having a better understanding of LCT demand allows for improved quantification and understanding of the associated impact. By having better foresight into the impact of local diversity on LCT usage, the value in adopting flexible solutions can be better quantified in comparison with conventional reinforcement. This is particularly necessary when considering local flexibility options; there is a need to understand how much flexibility is available and when [93].

The findings presented in this work demonstrate the impact of place-based socio-technical analysis in this regard, emphasising that whilst a non-localised modelling approach may still be considered an improvement to conventional simplistic load modelling techniques for headroom quantification, such approaches can risk misallocation of planning resources and failure to reinforce in time in certain areas. The findings also indicate that as the network evolves, local level challenges may emerge as to when and where investment in infrastructure and management solutions should be focused, emphasising the challenge with both heat and transport electrification and the extent that this may impact existing infrastructure.

Historically, due to the relatively predictable nature of domestic demand there was a lack of technical need for extensive monitoring and modelling of LV networks. As such, the vast majority of system wide demand related studies are conducted at a primary level [218] given the volume of secondary transformers and the data related challenges (as discussed in Section 3.3.1.1). However, with the uptake of locally sensitive LCTs, this work takes a higher resolution approach and is targeted at the secondary level. The findings are generalised indicators of the true headroom (downstream voltage limit breaches and LV cable overloads are not considered) and are used predominantly to reveal the impact of localisation and the need to consider socio-technical and socio-spatial dimensions in detailed technical studies. The final decision between adopting a flexible solution or reinforcement to manage the electrification of heat and transport as part of a development plan would still require technical assessment and a business case, but the developed method, can help identify where such detailed targeted assessment studies should be performed. This will require that existing network planning activities will need to be changed if the methods of this thesis were to be adopted.

3.6.2 Local Authorities and Policy Makers

The presented analysis takes the perspective of the DNO focusing primarily on distribution transformers. However, the benefits and implications of such modelling for external stakeholders is also considered of value.

Local authorities and policy makers are partly responsible for ensuring decarbonisation targets are met [239]. They have the ability to influence and guide specific decarbonisation pathways as there are various means of achieving these targets, particularly in terms of heat decarbonisation. This could include subsidies for retrofitting building stock with energy efficiency improvements in areas of high social deprivation to support specific technology uptake or subsidies for the technologies and installation costs. This requires high-level planning and a significant understanding of local requirements. The Scottish government's Local Heat and Energy Efficiency Strategies (LHEES) aim to establish local authority area-wide plans and priorities for improving the energy efficiency of buildings and decarbonising heat [240]. However, it is recognised that the feasibility of interventions from such parties are highly dependent on future network capability and headroom. As such, works including [241], are recommending that local government should have a statutory role in guiding the future development of local energy infrastructure, including investment decision-making. To do so effectively, whilst also addressing social objectives, they need an understanding of the capability of the network and future flexibility potential based on a localised understanding of consumer behaviour. This would allow for network investment to be optimised with better foresight of regional economic plans and local area energy plans.

The development of this methodology and the findings presented demonstrate the influence local sensitivities may have in relation to electrical infrastructure impact and subsequent investment requirements. As such, the analysis presented in this work has the ability to support a 'just transition' which is a key component of many national government strategies [76], by enabling policy makers and local authorities to better understand the wider impacts of place-based electrification in specific areas i.e. by having a better understanding of HP uptake impact in a specific region thus enabling co-developed plans with the DNO to be determined. This then allows for planning and funding allocation to be optimised with respect to 2030 targets in the net zero transition. This is particularly valuable when considering social welfare and fuel poverty [242]. It is highlighted in [241], that regions in England with the highest fuel poverty and coldest winter climates are not receiving the most heat funding. This reiterates that the social imbalance of wealth may inadvertently have an influence on network investment as early adopters and ‘able-to-pay NOW’ consumers tend to be more affluent and are typically located in areas with lower social deprivation.

More broadly, although the work focuses on the decarbonisation of heat and transport with an emphasis on EVs and HPs, the developed method has the ability to support wider decarbonisation analysis and assessment of diverse technological impacts on electricity infrastructure e.g. to investigate trade-offs between multi-carrier decarbonisation pathways. For example, by identifying areas where electricity infrastructure is particularly challenged by electrification, alternative methods of decarbonisation can be explored and the full ramifications and costs associated with deploying these solutions assessed. With limited knowledge into the impacts of decarbonisation pathways on electrical network infrastructure, local authorities and policy makers may inadvertently make decisions that would see decarbonisation become significantly more expensive than necessary. Exactly how to perform this multi-carrier analysis at sufficiently localised resolutions and at scale with consideration for socio-economic factors and existing infrastructure is a challenge many stakeholders in the energy transition are struggling to overcome. The developed method has the potential to feed into wider multi-disciplinary collaborative works that are seeking to tackle this problem.

A more direct application of the method may see social investors support increased uptake of HPs in less affluent areas as there is likely to be more headroom for them to do so without reinforcement. Equally funders may (through participation in the regulatory process) promote and potentially contribute financially to support reinforcement in more affluent areas so that those who can afford to install HPs have the ability to do so unimpeded by network capacity and lengthy reinforcement times.

3.7 Chapter Summary

The work has presented a novel high-resolution assessment methodology that enables quantification of electrified heat and transport impact on transformer headroom at scale using socio-economic indicators to inform the application of LCT consumption data. The value of this methodology for quantifying transformer headroom has been demonstrated on an existing physical transformer dataset and findings have been contextualised for different actors involved in the energy transition.

Findings from the analysis provide novel insights into the value of localised modelling with respect to socio-technical and socio-spatial analysis. In particular, they indicate that the broad link between social diversity and heat demand variation has the potential to influence decision-making. This is of particular concern in the near-term where affordability and access to LCTs is expected to be a barrier for those in areas with higher social deprivation. The findings also highlight an increasing need to consider the combined uptake of different LCTs with respect to the electrification of heat and transport. In particular, they emphasise the cumulative severity of this combined impact and confirm that unconventional demand-side management services will be required to avoid significant evening peak demands.

Chapter 4

A Scalable Geospatial Data-Driven Localisation Approach for Modelling of Low Voltage Distribution Networks and Low Carbon Technology Impact Assessment

4.1 Introduction

4.1.1 Motivation

As concluded in the preceding chapter, there is an increasing need to consider the combined uptake of different LCTs with respect to the electrification of heat and transport. The findings presented in Chapter 3 introduce the cumulative severity of this combined uptake and confirm that a requirement for further detailed modelling is necessary to ascertain the full implications.

With the evolution of distribution networks and the uptake of LCTs, the need to accurately model these networks has evolved to ensure cost efficient investment and to reduce the uncertainty surrounding the impact these technologies will have on existing infrastructure in different geographic areas. Such insights will support DNO decision making by informing the network planning and management requirements of key infrastructure. Also, supporting wider decarbonisation efforts within the context of local area energy planning by informing stakeholders on the impacts of their decarbonisation strategies.

In Chapter 3, a methodology was developed to allow for high-resolution analysis with recognition for local diversity at scales uncommon amongst the existing literature i.e. at a secondary transformer level across an entire DNO licence area. The analysis relates primarily to the impact of LCTs on secondary transformer headroom and excludes consideration for the direct impact of LCT uptake at an LV level. As such, with the recognition that LV networks – considered to be the last mile of electricity infrastructure – are also highly diverse, in terms of network topology and the underlying characteristics, there is scope to extend the modelling to reduce the growing uncertainty surrounding the impact different LCTs will have at an LV level [243]. This would allow for highly granular technical analysis at scale whilst accounting for the impact of diversity on LCT consumption.

4.1.2 Contribution

The key contribution of this chapter is the development of a novel scalable approach to localised LV network LCT impact assessment which couples the following two methodologies together as summarised by Figure 4.1. The value is outlined in terms of its ability to inform stakeholder decision making.

Firstly, the work builds on the previously established recognition that the heterogeneity of distribution networks, consumer demographic and building stock across a geographic area presents a complex set of interdependence that requires consideration when developing network modelling capabilities. Therefore, a scalable data-driven modelling methodology is described in this work that includes the mapping and integration of locally-specific spatial datasets (i.e. datasets with information pertaining to the local area) with network GIS data and builds on the existing works used to develop 'generic-GIS' electrical network models by including a local spatial reference that is used to support high-resolution place-based analysis and granular localised LCT demand modelling.

Secondly, a localised LV network assessment methodology is presented which incorporates modelling of both EVs and HPs. Where existing works generally infer heat demand from metadata (e.g. building characteristics such as house type and size) for HP modelling, this work expands on the approach described in Section 3.4.2 to include enhanced representation

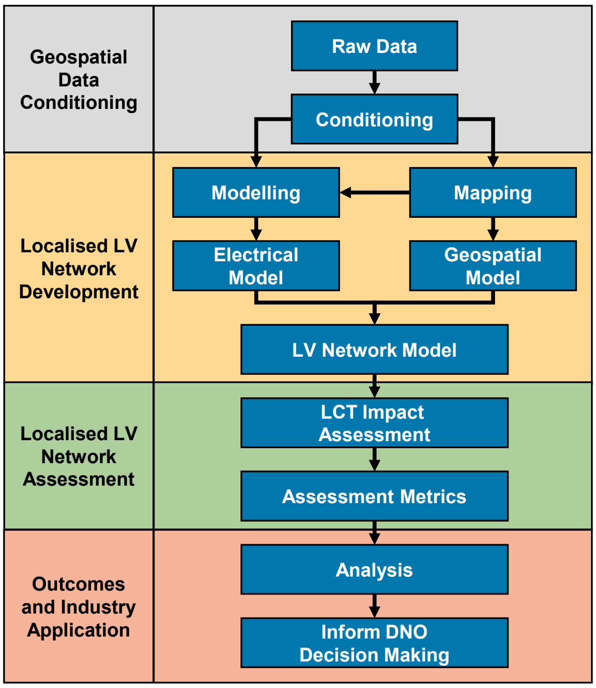


Figure 4.1. High-level overview of the methodology coupling for localised LV network LCT impact assessment.

of targeted areas. The developed methodology takes a statistical approach to LCT impact assessment.

The remainder of the chapter is organised as follows. Section 4.2 provides a review of the literature with focus on existing LV distribution network modelling techniques and the impact of LCT uptake at an LV level, this in part expands on the review described in Section 3.2.2. Identification of gaps through the literature review then forms the basis for the work conducted in this chapter. Section 4.3 describes the localised LV network development methodology. This includes description of the datasets considered in this work and the relevant conditional changes to the datasets previously described in Section 3.3. The associated mapping of the datasets and their application is also described as is the heuristic used to develop detailed representative LV network models. Section 4.4 provides a description of the developed assessment methodology and summarises the key assessment metrics used to quantify the impact of LCT uptake. Section 4.5 describes the assessment scenarios then presents the results and associated analysis. Section 4.6 presents a summary of the work described in this chapter.

4.2 Literature Review

4.2.1 Existing Approaches to LV Distribution Network Modelling

Distribution network modelling has evolved over a number of years, and to support academic research the IEEE Test Feeder Working Group has continually developed openly available distribution network test feeders for use by researchers. Schneider et al. identify that *"The purpose of these test feeders is to provide models of distribution systems that reflect the wide diversity in design and their various analytic challenges."* [244]. The diversity here referring to regional differences in the structure and operation of circuits across the world. As such, within the literature it is common to see the use of these models for distribution network studies e.g. Chikumbanje et al. use a low-capacity IEEE LV network model to investigate the grid expansion planning problem in sub-Saharan Africa due to the limited visibility of existing networks in the region. The network with case dependent adjustments was considered comparably representative for this type of analysis [245], whereas Prakash et al. use the same model in a different context to investigate the role of battery energy storage systems for ancillary service provision [246]. Whilst these models have the capability to support academic research and the generalisation of methods, with only a few examples of European LV networks, the models lack the breadth in representation necessary to meaningfully inform on physical infrastructure that through many years of development will have cultivated a uniqueness that such idealised and specific models fail to capture.

With this, alternative methods of modelling 'more representative' LV distribution networks are regularly sought, particularly when carrying out LCT impact and planning analysis e.g. Gan et al. developed a fractal model for statistical network creation in an attempt to capture the complex and disparate nature of physical LV networks [99]. The intention of this method is to support decision makers in drawing more robust conclusions than obtained through use of specific case study models i.e. the IEEE test feeders. The developed methodology is based on the generation and analysis of a large number of statistically similar networks, with common topological parameters and is able to reproduce realistic network topologies and lengths, with no simplifications regarding consumer location. However, due to the statistical nature of the method, it relies on synthetic technical information for the network assets. Nevertheless, this modelling technique has been used in a number of works, typically in the earlier stages of LV distribution network related research [100]–[102]. In a similar vein, taking advantage of recent advances in artificial intelligence, Liang et al. developed a machine learning-based approach for automated, customisable generation of test feeder creation using actual feeder models as inputs [103]. These approaches allow for modelling of ‘generic’ physical LV networks that are useful for broader assessments and the development of methodologies where less consideration is placed on specific networks and their relative locale.

To conduct more comprehensive assessments of existing infrastructure, it was recognised by Navarro-Espinosa et al. as part of the Low Voltage Network Solutions (LVNS) project [247], and in [94], [104], [248] that the creation of realistic LV distribution feeder models is a fundamental step in understanding the potential impacts of LCTs and that GIS data which includes both spatial and technical information pertaining to existing infrastructure can support this. As part of this body of work, Navarro-Espinosa et al. note various challenges with GIS data and present a method for translating GIS data into power system models using a systematic methodology to overcome observed GIS related issues and achieve full reconnection of LV feeders in cases where no other connectivity data is available. Through this work and the LVNS project, 25 realistic LV network models (128 feeders) for areas within the North West of England (operated by ENW) have been developed and are publicly available [247]. These models have been used in numerous other works including [88], [93], [249] demonstrating the value of GIS data-driven modelling for LV distribution network related research. Although the LVNS network models typically represent the largest available collection of GIS-network models for a particular area to-date, the anonymity of these networks ensures that there is no information available on the local characteristics e.g. building types and consumer demographic. This makes it particularly challenging to carry out place-based characterisation of the local demand through socio-spatial and socio-technical analysis, and tailored forecasting of LCT uptake. Whilst the occasional development of other individual isolated GIS-network models as in [105] is not uncommon within the literature, these networks tend to be created specifically for bespoke case study demonstration and are not derived with a centralised automated method that allows for scalable use across different areas.

Therefore, although GIS-driven network modelling has become more common within the literature in recent years, there is still a growing requirement to build on the improvements in GIS data quality and for enhancement through fusion with spatially explicit socio-spatial and socio-technical data that will inform LCT consumption and uptake. There is also a requirement to expand on existing GIS-network modelling heuristics by incorporating scalability to support automated and centralised place-based modelling of networks in different areas. This will allow for the detailed characterisation of network infrastructure and local conditions across different regions comprised of diverse characteristics.

4.2.2 Further Evaluation of Impacts from LCTs on LV Distribution Networks

As previously noted, research on the impacts of individual LCTs on distribution networks is plentiful. However, it has been established that literature on the combined effects of EVs and HPs on network infrastructure is comparatively scarce. This is particularly true for the combinational effects of EVs and HPs on network infrastructure across different locations with diverse characteristics in consideration of locally-specific socio-spatial and socio-technical indicators (in acknowledgement that the use of socio-economic indicators to assign LCT demand profiles in distribution network models is also relatively rare in the literature).

This is partly as in the early stages of HP related research, studies in the literature were limited by data that was either obtained from user surveys or small scale trials e.g. Caird et al. carried out an in-depth user survey which investigated the characteristics and behaviour of private householders and social housing residents using HPs for space and/or water heating, and examined the influence of user-related factors on measured HP system efficiency [250]. Alternatively, Kelly and Cockroft used monitored data from eight HPs to assess HP performance when retrofitting into a dwelling using a building physics-based approach that developed a parameterised HP model and a whole-building simulation model of one of the field trial houses [251]. With larger field trials and increased access to monitored HP data, HP related research has evolved beyond the built environment e.g. Love et al. developed a methodology to assess the impact of mass HP uptake on the electricity system using the RHPP dataset. The developed method creates an aggregated load profile for typical winter conditions and carries out analysis at the national level i.e. the impact on the peak demand as seen by the transmission network [87].

At a more granular level, in terms of the distribution network, several studies have sought to investigate HP impact at a household level e.g. Mancarella et al. present a methodology to assess and quantify the impact of HPs on LV distribution networks [100]. This study uses the fractal geometry method previously described to model the distribution network and assumes three-phase balanced connections, also using average profiles only. Navarro and Mancarella went a step further and developed a probabilistic methodology based on Monte Carlo simulations to assess the impact of HPs on LV distribution networks [252]. Published prior to the RHPP dataset, this study relies on use of CHP demand information to inform heating consumption which although in certain instances may have similar demand requirements to HPs is still an approximation. Nevertheless, these studies are widely cited and are typically the benchmark works for offering insights into HP impact on distribution networks. However, modelling HP electrical load with the geospatial granularity appropriate for LV distribution networks imposes unique constraints that are not fully addressed and there are limitations with both approaches taken.

As such, although HP related research and the associated modelling techniques have evolved significantly over the last decade in-line with an increasing relevance and maturity of the technology in respect of the net zero agenda. It has been evidenced in the literature review presented that existing works focused on HP distribution network impact analysis have tended to rely primarily on the use of either physics-based models or limited monitored data[11] without sufficiently capturing the geographical context of the households involved.

Therefore, in addition to the growing requirement of building on existing GIS-network modelling, the scarcity of research surrounding combined EV and HP impact, and the use of socio-economic indicators to assign LCT demand profiles in distribution networks. There is also scope to probe gaps in the literature on the approach taken to model temperature correlated HPs whilst capturing the geographical context of the households and the distribution network.

4.3 Localised LV Network Development

This section of the chapter describes the methodology used to develop localised LV network models which is summarised by Figure 4.2. This includes a description of the data used to drive model development and the associated transformation process. A description of how the

[11] Use of monitored data has an advantage over physical demand models as it can capture individual household behavioural and diversity effects that are difficult to parametrise and validate in physical building models. However, monitored data can be limited in terms of applicability to different geographic areas unrepresentative of the monitored conditions.

method for modelling consumer demand is adapted from Section 3.3.2.1 is also provided along with a summary of a small sample of developed networks.

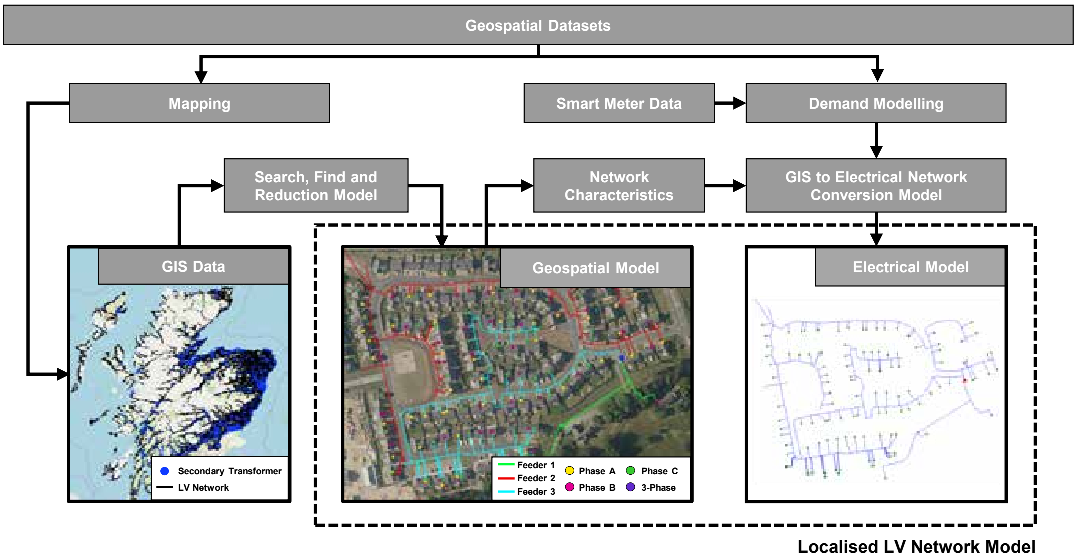


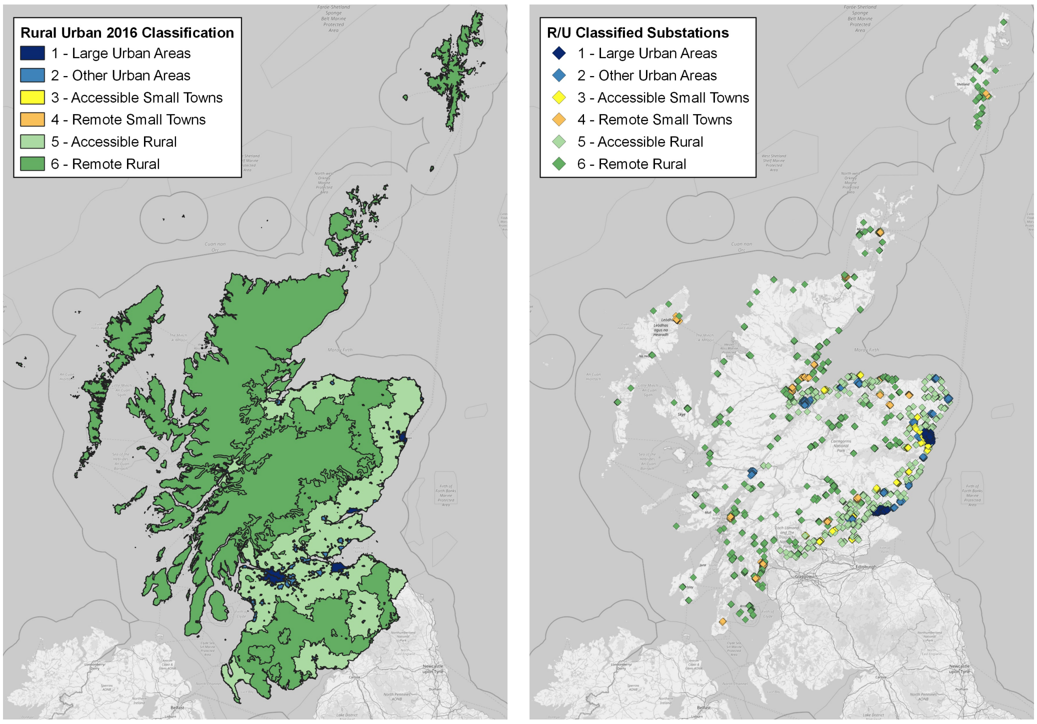
Figure 4.2. High-level overview of the localised LV network development methodology.

4.3.1 Description and Mapping of External Datasets

As previously mentioned, GIS data can be integrated with external geospatial datasets which allows for enhanced classification of networks and localised targeted modelling. The following describes the external datasets considered in this chapter and their integration with the relevant GIS data. Note that for the datasets described previously in Section 3.3, only the mapping application for the work in this chapter is described.

4.3.1.1 Rural/Urban Classification

The Urban Rural Classification 2016 [253] classifies Scotland into categories based on (1) population, defined by the National Records of Scotland (NRS) [254] and (2) accessibility, which considers drive time analysis to distinguish between remote or accessible locations. Figure 4.3 highlights this, where Figure 4.3a presents a map of Scotland showing the 6-fold classification approach. Settlement (defined by the NRS is a group of high-density postcodes whose combined population rounds to 500 people or more) data produced by the NRS forms the basis for population benchmarking where: Large Urban Areas are populations of 125,000 or more, Other Urban Areas are populations of 10,000 to 124,999, Small Towns are populations of 3,000 to 9,999 and Rural Areas are populations of less than 3,000 [253]. For the 6-fold urban rural classification, in terms of area qualification: Accessible Areas are defined as areas that are within a 30-minute drive time from the centre of a Settlement with a population of 10,000 or more, whereas, Remote Areas have a drive time which is greater than 30-minutes [253]. The geospatial information for each classification presented in the urban rural classification 2016 (8-fold, 6-fold and 2-fold) is mapped to the GIS secondary transformer dataset as shown in Figure 4.3b which provides a means of distinguishing between different LV networks via their location.

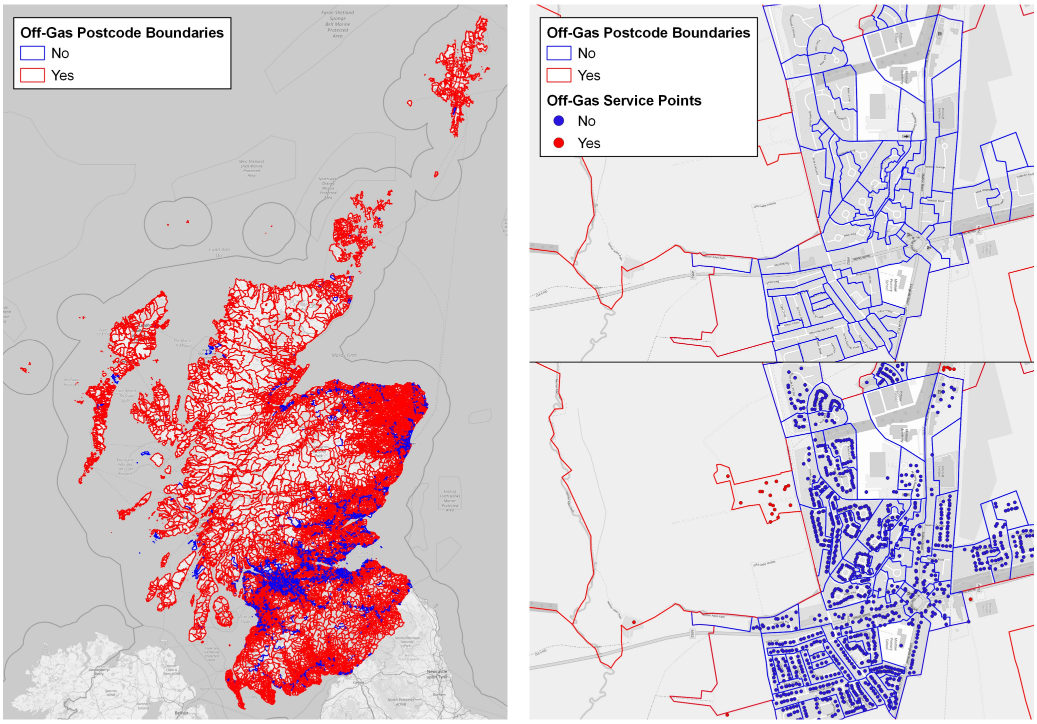


(a) (b)

Figure 4.3. Mapping of urban rural classification and transformer GIS dataset. (a) 6-fold urban rural classification. (b) Urban rural classification of the transformer GIS dataset.

4.3.1.2 Off-Gas Postcodes

Xoserve (data service provider for Britain's gas market) records a list of GB postcodes that are unconnected to the mains gas network [255]. This list, identifies postcodes that are purely isolated from the gas network in that they have no domestic or non-domestic mains gas connections i.e. a postcode where a single business is connected to the gas network and no households, is not considered to be off-gas [255]. This information is first mapped to a shapefile containing geospatial digital postcode boundaries for Scotland [229]. Then from this, postcodes and gas connection status are mapped to GIS service points as highlighted in Figure 4.4, where Figure 4.4a is the off-gas geospatial postcode boundaries and Figure 4.4b is the off-gas classification of the service point GIS dataset. Therefore, for each load in the licence area, the associated postcode and whether it is likely to be connected to the gas network or not is now available. This provides the capability for targeted modelling of off-gas networks (as necessary) which are considered a decarbonisation priority.



(a) (b)

Figure 4.4. Mapping of off-gas postcodes and service point GIS dataset. (a) Off-gas geospatial postcode boundaries. (b) Off-gas classification of the service point GIS dataset.

4.3.1.3 Distribution Network GIS and Gas Demand Data

From the available network GIS data previously described in Section 3.3.1.1, data pertaining to the secondary transformers, LV underground cables, service points and link boxes are used to support the work in this chapter. In terms of the gas demand data described in Section 3.3.1.3, this again is used to inform HP consumption data.

4.3.1.4 Revisiting the Scottish Index of Multiple Deprivation

The SIMD is described in Section 3.3.1.2 and a similar mapping process is also applied here. For the work concerned in this chapter, the SIMD is used to classify the service point GIS dataset as shown in Figure 4.5. This goes further than the high-level mapping of the SIMD to secondaries as the consumers are directly classified as opposed to the assumption that all consumers connected to a specific secondary have the same SIMD classification. This provides the means to capture diversity of demand across areas comprising of varying socio-economic criteria on specific networks.

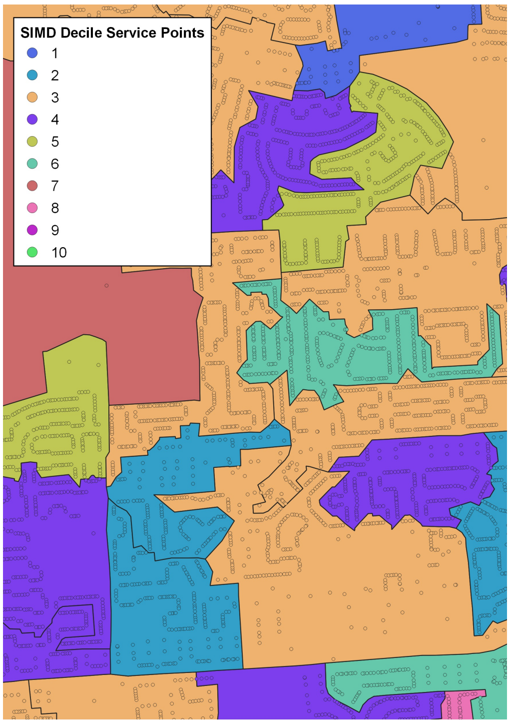


Figure 4.5. SIMD classification of the service point GIS dataset.

4.3.2 GIS to Network Model Transformation Methodology

The GIS to electrical network transformation methodology is split into two models; the Search, Find and Reduction Model, and the GIS to Network Model, where the approach used to develop these models is described in detail within this section. These models have been developed in Python with use of the GeoPandas package [219]. The electrical network models are developed in OpenDSS [256] which allows for unbalanced quasi-static time-series analysis via the Python COM interface.

4.3.2.1 Search, Find and Reduction Model

To model a secondary transformer and associated LV network independently, the *Search, Find and Reduction Model* has been developed for this work. Figure 4.6 demonstrates the model functionality for a single secondary transformer. From the initial extremely large search space which covers the entire licence area in the north of Scotland, a single transformer of interest is identified[12] and a suitably 'large' radius applied. From this, the GIS data search space is then reduced to within this radius. The radius is modelled to be sufficiently 'large' that the associated LV network of any given transformer would not extend beyond the radius boundary.

For cabling, the GIS stores spatial information in the form of one or more sequences of coordinates that create a multi-point line i.e. a series of coordinates form a segment, and a series of segments form a multi-point line, and a series of multi-point lines would then in principle form a feeder. However, this format does not support the connectivity of lines necessary for conventional power flow modelling (as multi-point lines are not connected), therefore, to facilitate this, common points (individual sets of coordinates) must be identified where one or more multi-point lines start or end. From this, a Breadth First Search (BFS) algorithm is executed within the now significantly reduced search space and the common points or 'nodes' are used to drive the algorithm (note that multi-point lines containing start or end points within a multi-point line are also identified). BFS is a graph-based search algorithm that begins at a given node known as the root node (in this case the transformer's coordinates) and then explores all neighbouring nodes [257]. For each of the neighbouring nodes, it then explores the available solution space, and this continues until all connected nodes are located [257]. BFS algorithms are often computationally expensive therefore by reducing the search space, modelling time is significantly improved. The algorithm is executed to locate all LV cabling connected to the transformer and then when all cabling is located, the algorithm is executed based on the network endpoints to locate the loads. An example of this process is shown in Figure 4.7.

[12]DNOs will have their own specific reasons for selecting a particular transformer and associated network to analyse, this could be due to the characteristics of the transformer, the characteristics of the load supplied by it, or any other number of reasons including concerns raised with the volume of EV/HP uptake for a specific area as identified through forecasting. The transformers and networks selected for this work have been used to demonstrate the methodology and areas with comparatively different heat demand have been selected for the analysis.

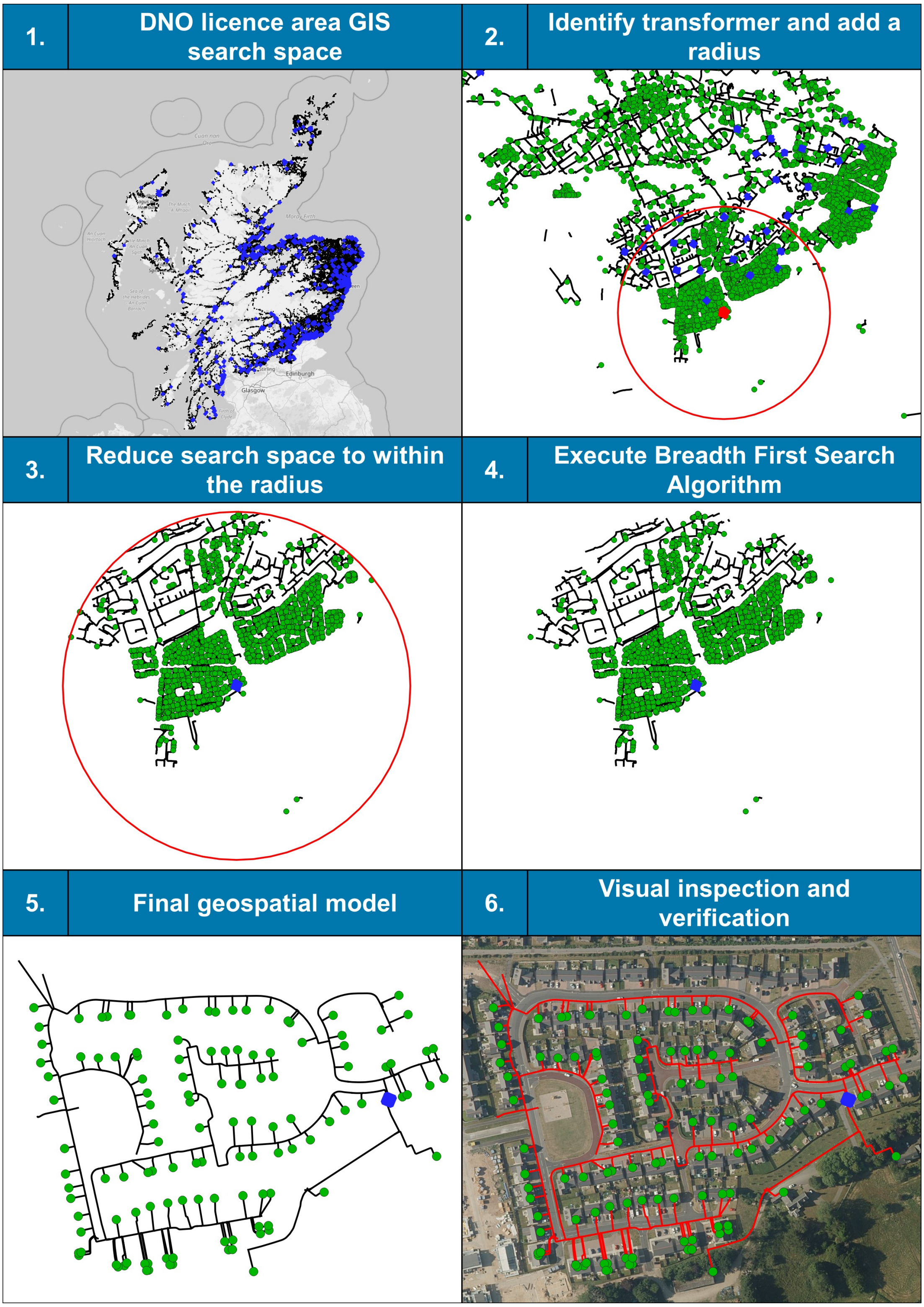


Figure 4.6. Process involved in the Search, Find and Reduction model.

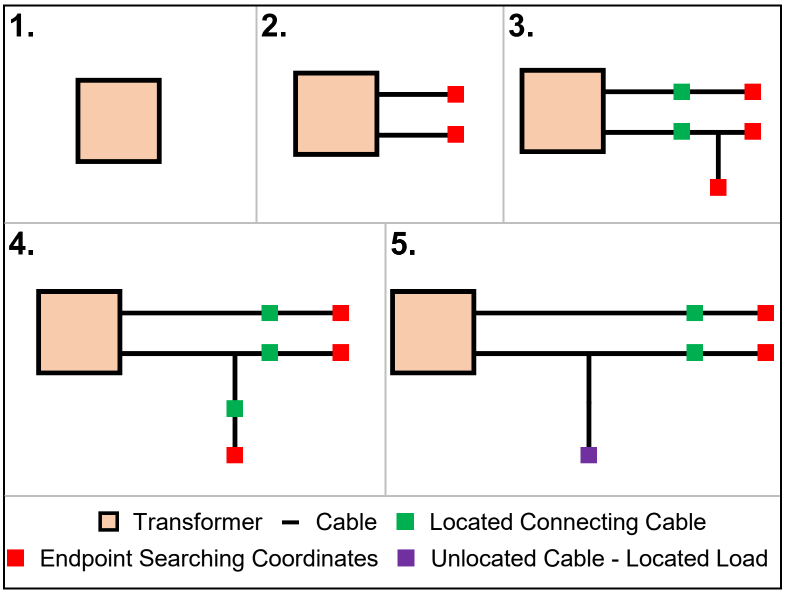


Figure 4.7. Demonstration of the Breadth First Search algorithm for cable and load connectivity.

In [258], a number of GIS data quality related issues were raised when using BFS algorithms for line connectivity, particularly in relation to multi-point line start and end coordinates not matching i.e. there is a ‘small’ gap between the lines which influences the algorithm’s ability to identify connecting lines. However, it is noted that since [258], the quality of GIS data has improved, and although still existing to some degree the issues raised are far less prominent for cabling in the observed dataset. In an attempt to account for this in the current modelling a search tolerance has been used to identify start and end points in close proximity when no identically matching coordinates are found before searching for network service points. It is noted that this is also an issue when there are link boxes in between lines, therefore all link boxes have been assumed open and essentially operate as a breaking point between feeders supplied from different transformers.

To validate the generated models an expected number of feeders and consumers for each feeder is compared with the final generated network. Should these match, the model would then be visually inspected by a network planner, overlaying the geospatial model on different visualisation maps. The judgement of model feasibility and representativeness therefore lies with this actor. Should the connection points not match for any particular reason, e.g. lack of data or an error with the connectivity, the same actor would be required to investigate the reasoning. In a future scenario with increased visibility through improvements in monitoring and digitalisation additional functionality can be built in that would help to minimise the need for this verification stage and to manage model uncertainty e.g. use of strategically placed monitoring and smart meter data at the LV level to support validation.

4.3.2.2 GIS to Electrical Network Conversion Model

Having generated the independent shapefiles for the transformer, cabling and loads, these are then converted from GIS data format to OpenDSS power flow modelling format using the conversion model presented in Figure 4.8. The individual multi-point lines are first identified, and it can be seen that multi-point lines do not always start at the end of another but often at a pair of coordinates within the multi-point line. This poses a challenge for conventional electrical modelling bus definition. Therefore, the associated joints based on intersecting vertices (essentially where pairs of coordinates match) are identified and the multi-point lines are segmented at these points maintaining raw cable information and adjusting cable length. Another dataset challenge is the orientation of the coordinate sequences stored in the multi-point lines. Therefore, these are re-orientated as necessary to improve model workability. The lines are then further segmented to individual pairs of coordinates for granular representation. Finally, the shapefiles are converted to OpenDSS network format by translating all raw GIS network information into the electrical technical parameters necessary for LV network modelling in OpenDSS e.g. cable length and type, transformer rating and phasing. No detailed information for line impedance values and current ratings is provided in the GIS dataset therefore these are taken from [35]–[37] and aligned with cable type as further described in Appendix B. Fundamentally, the availability and quality of the technical information recorded in the GIS is what drives the accuracy and representativeness of the developed LV networks. This is varied across the licence area and as expected, is particularly lacking in areas where the DNO would have historically had limited visibility e.g. sparsely located remote rural networks with low consumer populations and an aged infrastructure. To develop detailed and highly representative LV network models, areas with higher data availability were focused on. However, a point of consideration with this approach is the possibility that higher data availability may indicate that these areas of network have recently been developed e.g. new housing estates that have been sized with consideration for the uptake of LCTs and an energy efficient building stock.

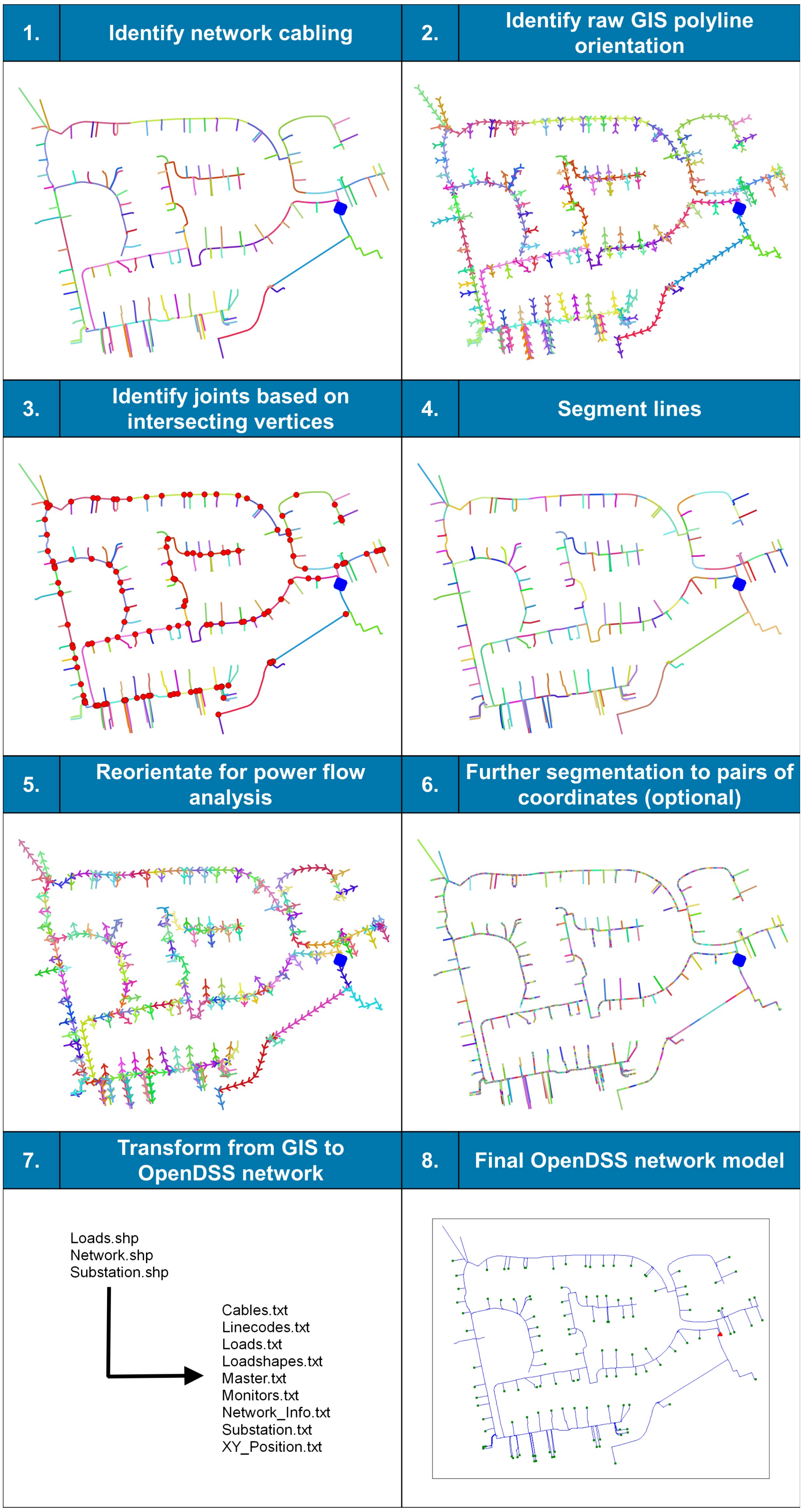


Figure 4.8. Process involved in the GIS to Electrical Network Conversion model.

4.3.3 Final Developed Networks

Figure 4.9 presents an area in the north of Scotland highlighting the location of several developed LV distribution network models. These networks have been sampled to demonstrate the scalability of the modelling methodology across a geographic area. A breakdown of the key individual network characteristics is presented in Table 4.1. The allocation of loads to phases is provided in the raw GIS data, characterised by the network operator as 'Surveyed', 'Derived' or 'Assumed'. Networks with higher concentration of surveyed loads have been focused on. However, derivation and assumption of individual load phase allocation is unavoidably present in certain instances. The networks are classified based on the Urban Rural 2016 6-fold classification [253] and fall into the categories of either Large Urban Areas, Other Urban Areas and Accessible Small Towns. They are connected to the gas network and annual postcode level gas demand consumption data is available.

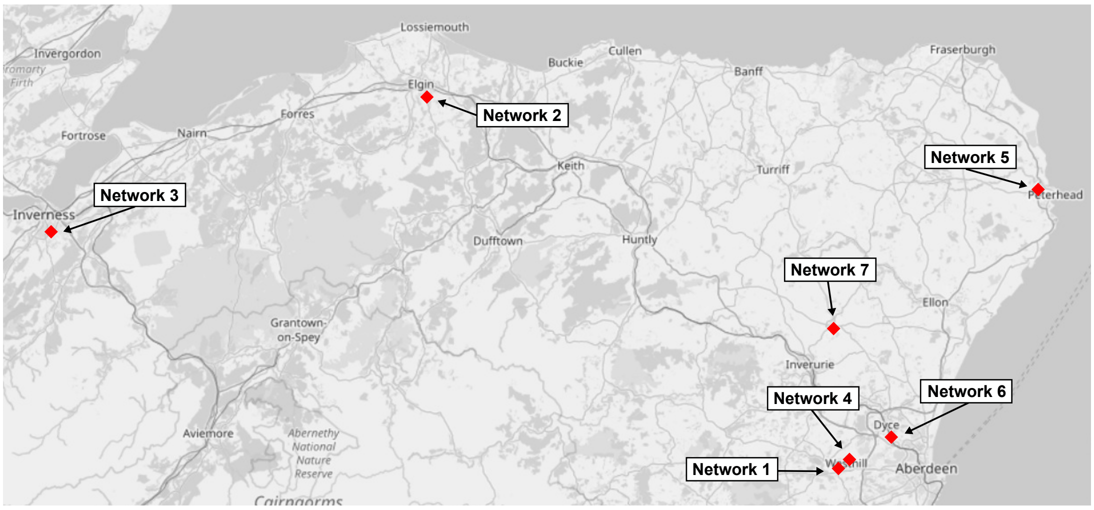


Figure 4.9. Location of sample networks across northern Scotland demonstrating methodology scalability.

Table 4.1. Summary of sample network characteristics

Network	No. Feeders	No. of Loads	Phase Distribution			Total Cable Length (m)	Average Annual Postcode Gas Demand (kWh)
			A	B	C		
1	5	316	135	91	90	8,305	18,937
2	6	406	141	136	129	9,689	9,369
3	4	125	46	43	36	3,115	13,357
4	5	176	60	63	53	5,652	20,749
5	4	250	106	65	79	7,006	9,893
6	2	41	13	13	15	946	13,658
7	2	89	43	24	22	2,498	16,037

Figure 4.10 provides a visualisation of the topology for network 2 in its simplest form. This is followed by a detailed visualisation shown in Figure 4.11. The detailed visualisation shows the network against an Ordnance Survey map in Figure 4.11a and with aerial imagery in Figure 4.11b. This demonstrates the highly representative nature of these networks and the capability of the methodology. Visualisation of the remaining sample networks are provided in Figure 4.12 and Figure 4.13.

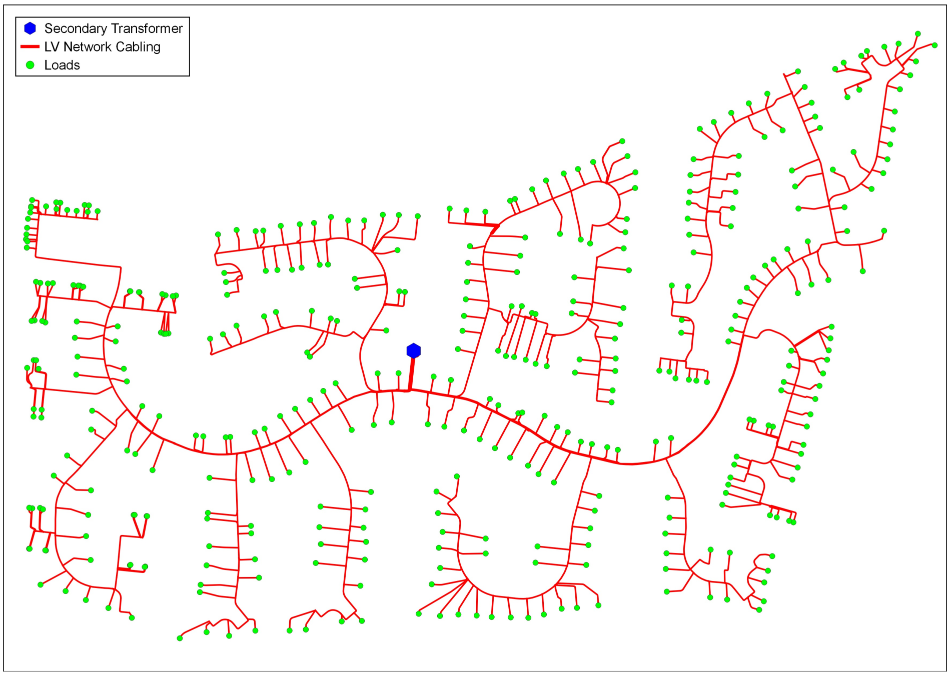
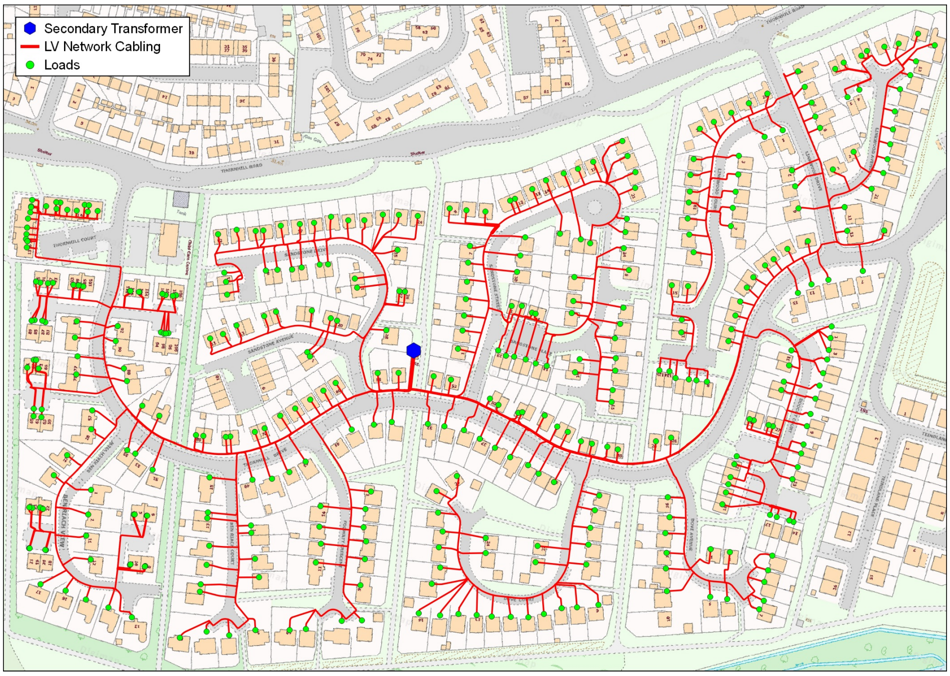


Figure 4.10. Basic visualisation of network 2.



(a)

(b)

Figure 4.11. Detailed visualisation of network 2. (a) Ordnance Survey MasterMap topography layer [259]. (b) Aerial imagery [260]. Copyright statement: © Crown Copyright and Database Right 09/11/23. Ordnance Survey (Educational Service Provider Licence Number 100025252). © 2023 Microsoft, Microsoft product screen shot(s) reprinted with permission from Microsoft Corporation.

Figure 4.12. Basic visualisation of the remaining sample networks.

Figure 4.13. Detailed visualisation of the remaining sample networks with aerial imagery. Copyright statement: © 2023 Microsoft, Microsoft product screen shot(s) reprinted with permission from Microsoft Corporation.

4.3.4 Demand Modelling

The process of using the LCL smart meter data to capture demand diversity in terms of SIMD classification is described in Section 3.3.2.1. As the work in Chapter 3 is carried out at a secondary transformer level, an assumption is made that all consumers connected to the secondary would have the same SIMD classification. In this chapter, the individual loads are classified as described in Section 4.3.1.4 which negates the need for this assumption. Therefore, in principle the methodology for modelling consumer demand and capturing diversity across different areas remains the same but the application is different. In this work the granular marginal variation of demand for each secondary is also captured for networks where consumers are classified with different SIMD deciles as shown in Figure 4.14.

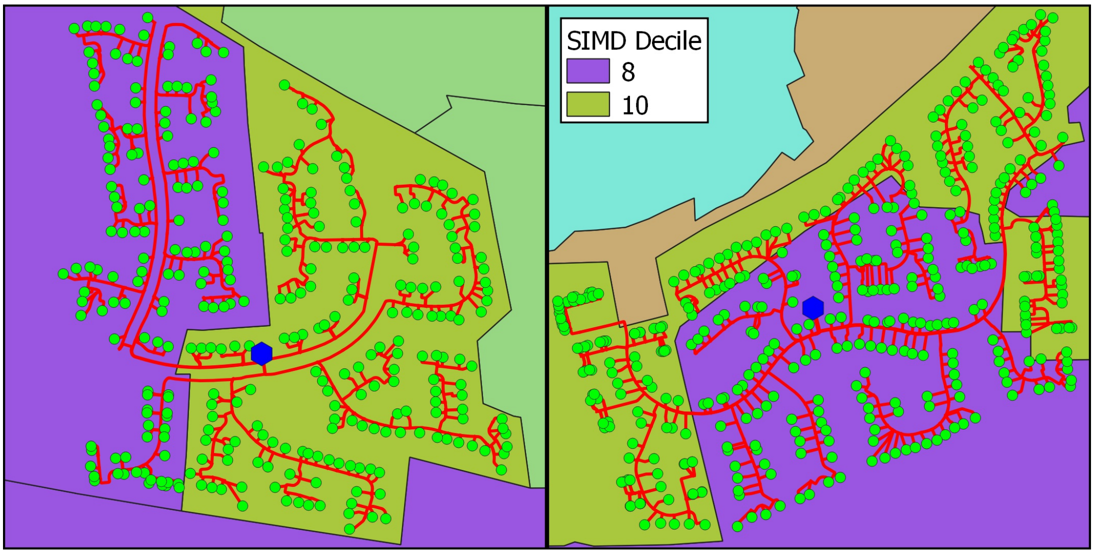


Figure 4.14. Visualisation of LV network consumer demand variation for each SIMD classification.

4.4 Localised LV Network Assessment

In this section, a detailed combinational LCT impact assessment methodology is developed and coupled to the methodology described in Section 4.3. The corresponding sections describe this coupling and detail the assessment approach. Description of how the HP modelling approach as described in Section 3.4.2 is adapted is also provided along with description of the metrics used to quantify the results.

4.4.1 LCT Impact Assessment Methodology

A detailed summary of the developed methodology and coupling is presented in Figure 4.15, where the mathematical notation presented is described as follows: t represents the daily time interval taken based on the number of half hourly intervals in each day, n represents the number of load sample iterations and p represents the percentage penetration of HPs and EVs distributed in the network (note these can vary independently).

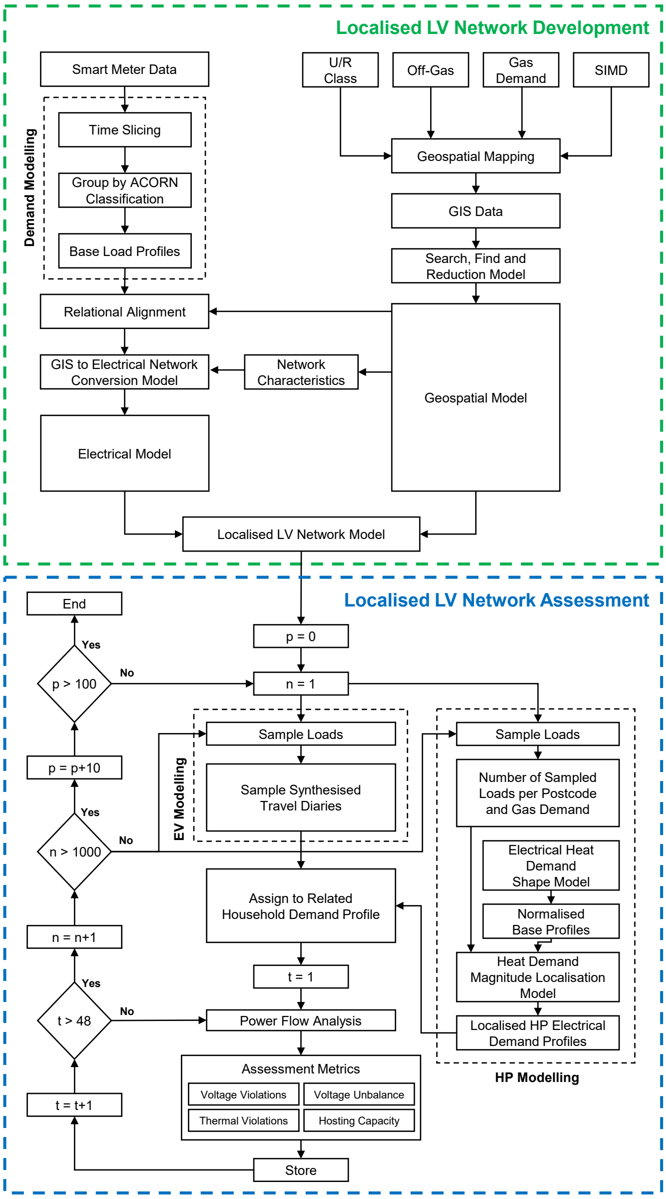


Figure 4.15. Localised LV network development and assessment methodology coupling.

4.4.2 EV and HP Modelling

In this chapter, the same EV modelling approach as described in Section 3.4.3 is used. The HP modelling approach is broadly similar to the method described in Section 3.4.2. However, for this work the method has been adapted to support targeted use of the recorded gas demand data. This negates the need to use the developed relationships in Section 3.3.2.2 and allows for direct use of associated gas demand for specific areas of network.

In Section 3.3.2.2, the developed SIMD-gas CDFs are sampled to ascertain the broader impact of socio-economic factors. Here the direct values are used to obtain the representative impact of a physical network and its household heating requirements. Individual postcode and the associated gas demand information are available from public domain sources in the UK [221]. Therefore, in adaptation of Figure 3.7, Figure 4.16 demonstrates how the individual postcode mean annual gas demand is now used as the primary input (the individual colours represent each postcode associated with the network) used to generate localised HP profiles. An average postcode mean annual gas demand for the related postcodes is also provided for each network in Table 4.1 to give some insight into the varying gas demand requirements.

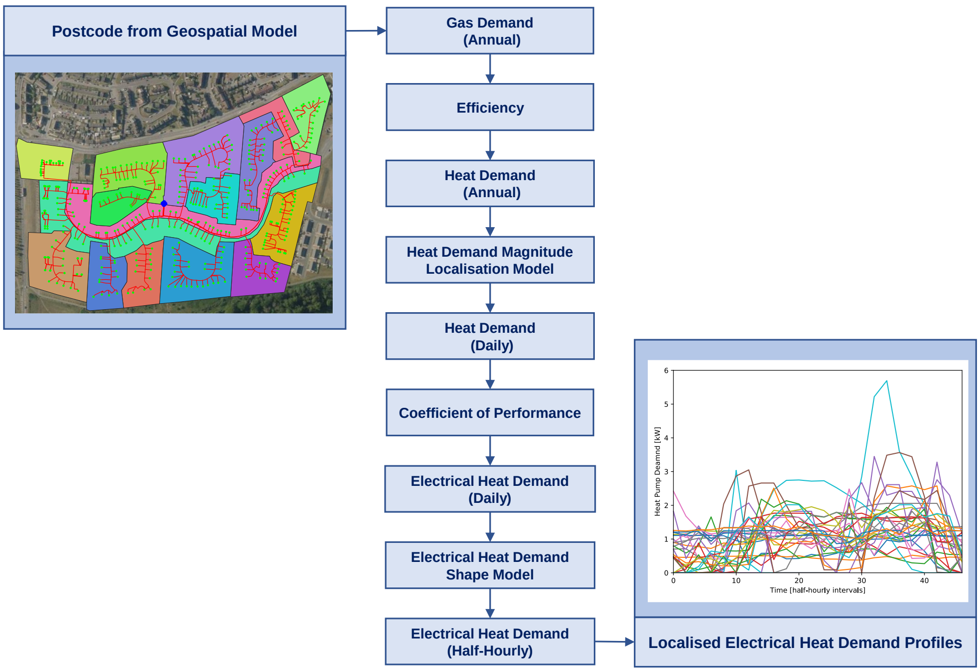


Figure 4.16. Methodology used to convert annual gas demand from direct postcodes to localised electrical heat demand profiles.

The methodology is updated such that HPs are distributed based on the penetration percentage and the spatial distribution is used to determine the incumbent postcode and thus the mean annual gas demand for each load. This is then used to generate a representative localised HP demand profile for each load. An illustrative example of this is provide in Figure 4.17.

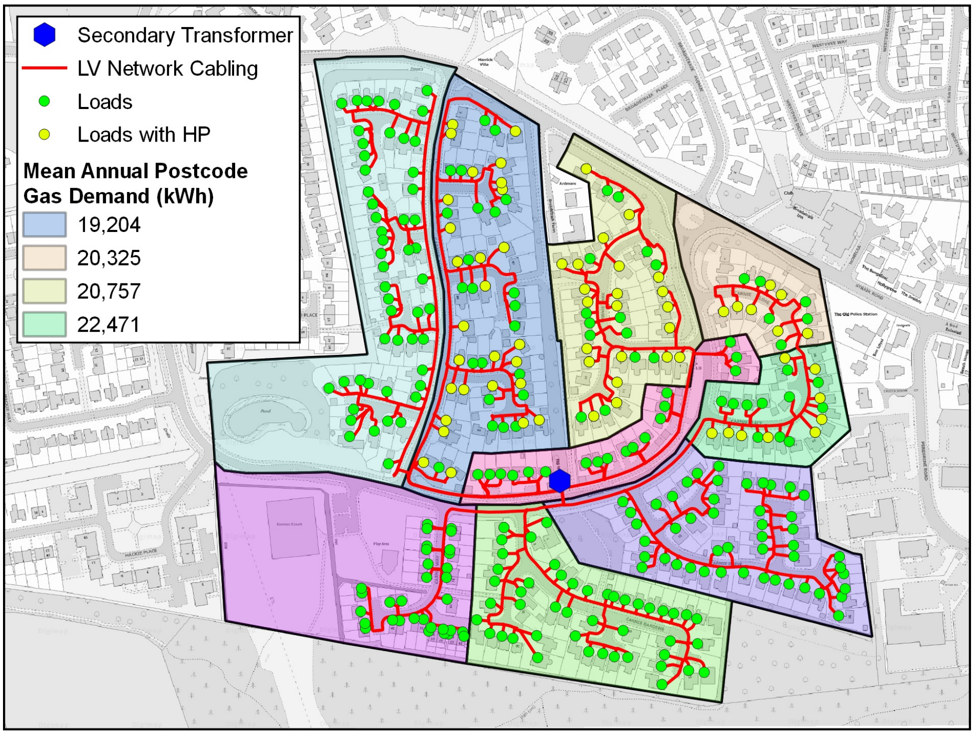


Figure 4.17. Illustrative example of method used to obtain annual gas demand for individual loads based on HP distribution and postcode.

4.4.3 Assessment Metrics

Three different assessment metrics are used to quantify the impact of LCT uptake on the concerned LV distribution networks: network violations, voltage unbalance and hosting capacity. These metrics demonstrate the methodology outlined in this chapter and are summarised as follows:

Network Violations: Thermal overload and over/under voltage are network issues that can occur as a result of LCT uptake [261]. Over/undervoltage relates to when the upper and lower statutory voltage limits (+10%,−6% in GB) [62], are breached. An overvoltage situation can occur when the current injected by LCTs such as solar PV or V2G significantly exceeds the current absorbed by the local demand, causing the voltage to rise beyond the upper statutory limit. An undervoltage situation can occur due to an increase in demand from LCTs such as HPs and from EV charging that would see additional current flow to the network, consequently causing the voltage to drop beyond the lower statutory limit [261]. Thermal overload relates to when the current exceeds the rated current capacity of the assets, typically applicable for cables and transformers [261]. Excess current can cause overheating and subsequent damage to the assets which can increase network losses, impact longevity and reduce reliability. As a result, voltage and thermal violations are considered to be key metrics for quantifying the impact of LCT uptake and are subsequently used in this work.

Phase Unbalance: As previously established, LV networks in practice are considered to be unbalanced networks where the phase unbalance (or imbalance) primarily stems from asymmetrical load distribution and temporal variations in load magnitude [262]. This unbalance results in an unequal distribution of power across the conventional three-phases and can result in an increase in network losses and an underutilisation of network capacity. A number of works have raised concern with the potential detrimental impact LCTs will have on phase unbalance e.g. in [263] the impact of solar PV was considered. This is of particular concern for already heavily unbalanced networks which are common in practice (particularly in a remote rural setting). ENA Recommendation P29 [264] provides insight into the planning limits for voltage unbalance in the UK, indicating that unbalance should be estimated using the voltage unbalanced factor (VUF) at any given measurement point, expressed by (4.3) which is calculated from (4.1) and (4.2) as described in [265]. Where V_{ab}, V_{bc}, and V_{ca} are the three-phase unbalanced line voltages V_p and V_n are the two symmetrical components of the line voltages, $a = 1\angle 120°$ and $a^2 = 1\angle 240°$.

$$V_p = \frac{V_{ab} + (a \times V_{bc}) + (a^2 \times V_{ca})}{3} \tag{4.1}$$

$$V_n = \frac{V_{ab} + (a^2 \times V_{bc}) + (a \times V_{ca})}{3} \tag{4.2}$$

$$VUF = \frac{|V_n|}{|V_p|} \times 100\% \tag{4.3}$$

As DNOs are expected to conform to this standard, and of the expressed concerns with voltage unbalance on network losses and hosting capacity, this work considers the VUF as a key assessment metric in quantifying LCT impact.

Hosting Capacity: As the hosting capacity relates to how much LCT penetration a given LV network can accommodate without breaching network operating standards or component physical limits it is considered to be a highly informative assessment metric [261]. In this work the hosting capacity is measured in terms of headroom based on the apparent power that instigates a network voltage or thermal violation on each individual feeder [93]. This can be expressed as:

$$H_{f,t} = min(S_f^{Tlim}, S_f^{Vlim}) - S_{f,t} \tag{4.4}$$

where $H_{f,t}$ is the headroom for each feeder f at time t, $S_{f,t}$ is the apparent power on each feeder, S_f^{Tlim} is the thermal limit of each feeder head cable obtained from:

$$S_f^{Tlim} = 3 \times I_f^{lim} \times V_{max} \tag{4.5}$$

I_f^{lim} is the maximum current rating of the feeder head cable and V_{max} is the maximum allowable voltage which is +10% of the nominal in this instance (the maximum is taken to give a conservative representation). S_f^{Vlim} is obtained by using a similar linear regression method as adopted in [93]. Figure 4.18 provides an example of this for network 1 feeder 5 where S_f^{Vlim} is based on the minimum $S_{f,t}$ that results in a voltage violation. The region to the left of this value (highlighted in green) is used for the network headroom assessment in this work and would be considered the standard operating region for network operators. The yellow region is where headroom is likely to be more dynamic and dependent on LCT usage patterns and install location. The distribution also shown in Figure 4.18 indicates that the voltage violation likelihood increases with $S_{f,t}$ in this region. With this, there is an opportunity to develop active solutions that have the capability to unlock and efficiently utilise the capacity available in this operating region.

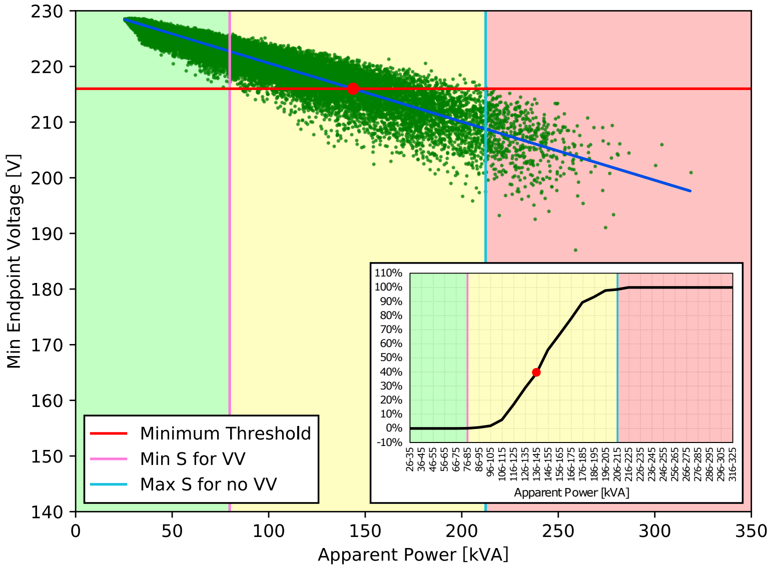


Figure 4.18. Minimum endpoint voltage versus apparent power (S) to determine voltage violation (VV) headroom operating regions.

4.5 Results and Discussions

The coupled methodology described in the previous sections is formalised through the assessment of two different LV networks (network 1 and 2 in Figure 4.9) to demonstrate the potential for scalable localised LV network modelling and the necessity for combinational LCT impact assessments. Such quantification provides modelling justification and supports targeted network investment decision making and emphasises the potential for area specific flexible network management. The assessment of each network considers three scenarios for each metric; scenarios 1 and 2 consider the uptake of EVs and HPs in isolation and scenario 3 considers a combination of both HPs and EVs. Scenarios 1 and 2 allow for distinction of individual technology impact which supports analysis of scenario 3. The results and discussion section are categorised against the key assessment metrics defined previously in Section 4.4.3. Note that the two networks have radically different heating requirements with network 1 having an average postcode gas demand of 18,937 kWh compared with network 2 which has 9,368 kWh.

4.5.1 Network Violations

Figures 4.19–4.24 summarise the results for the Monte-Carlo impact assessment of voltage violations for networks 1 and 2 respectively. Figure 4.19 and Figure 4.20 consider the range of minimum network endpoint voltages against a range of technology penetrations. For the EV scenario in both instances a broad range of minimum endpoint voltage is identified for each penetration quantity across the sample. Such variation is reflective of EV location and the variation in charging patterns. It can be seen that the lower statutory limit of 216 V is breached in certain cases with as little as 20% penetration. The impact from EVs is similar on both networks though network 1 is marginally worse. In terms of voltage violations from HP penetration, network 1 is significantly worse than network 2. This is to be somewhat expected due to the influence of heat demand localisation in the modelling. Where analysis suggests that the associated housing stock for network 2 has been built within the last decade therefore is likely to have increased building efficiency compared with an aged building stock for network 1. Other factors such as average building floor area size and consumer affluence may be influencing the recorded gas demand. In the case of the combined scenario, the number of violations are significantly increased. This emphasises the scale of the combined impact of both EVs and HPs on both networks.

In Figure 4.21 and Figure 4.22, the average minimum endpoint voltage across all samples for each penetration and associated time interval is presented for network 1 and 2 respectively. The three-dimensional aspect allows for time series analysis of individual technology impact. For the EV scenario on both networks, voltage violations primarily occur around the traditional evening peak as penetrations increase. This is a direct consequence of the modelled routine charging schedules, in that consumers would typically plug-in on their return home from work. The combined effect of all consumers having similar evening charging patterns results in a significant increase in demand and a large drop in the minimum endpoint voltage. For the HP scenario, voltage violations occur around the same time in the evening at higher penetrations though with less of a drop. However, unlike with the EVs an early-morning dip in the minimum endpoint voltage is noticeable and can be attributed to morning space heating demand requirements. This is particularly prominent on network 1 at higher penetrations and less evident for network 2. The combined scenario for both networks, results in a much larger drop at the evening peak with increased early-morning violations at higher penetrations, specifically for network 1. This combined impact is highly significant, particularly when considering demand side management applications. In isolation the EV scenario indicates peak shaving through scheduled EV charging could be deployed to reduce the evening peak demand with minimal impact during other periods of the day. However, the combined scenario identifies that with the mixture of EVs and HPs in the network, peak shaving or scheduled charging may coincide with the early-morning heat demand requirements. This is exacerbated for network 1 which has greater early morning violations at increased penetrations than in network 2, indicating that network 2 may have more scope for flexible management than network 1. Ultimately, this emphasises the need to consider the combination of different LCTs in parallel when conducting impact assessments and in the development of flexible demand side management techniques that are sensitive to the mixture of key LV connected LCTs and the inherent heterogeneity of local conditions.

The voltage violation density heatmaps shown in Figure 4.23 and Figure 4.24, provide further insight into the extent the combined LCT impact has across the two independent networks. The figures show spatially the concentration of network buses where a voltage violation has occurred at any time interval across the sample. The darker end of the colour scale indicates a higher density of violations i.e. voltage violations occur more frequently at these buses than others. As expected, there are a higher number of violations in the combined scenarios and in the EV scenarios compared with the HP scenarios. The concentration of voltage violations increases with distance in relation to the secondary transformer and is therefore prominent on the longest feeders. However, the number of consumers connected to each feeder, the electrical distance between consumers, phase allocation and cable impedance are several other potential contributing factors influencing where these violations occur in the network. Fundamentally, the heatmaps presented indicate that a combined uptake of both EVs and HPs is likely to result in an increase in the number of voltage violations across different areas of network. It is acknowledged that transient voltage excursions are allowed according to the distribution network code within allowable limits and that sufficiently granular data may reveal additional perturbations which must be borne in mind when assessing outcomes.

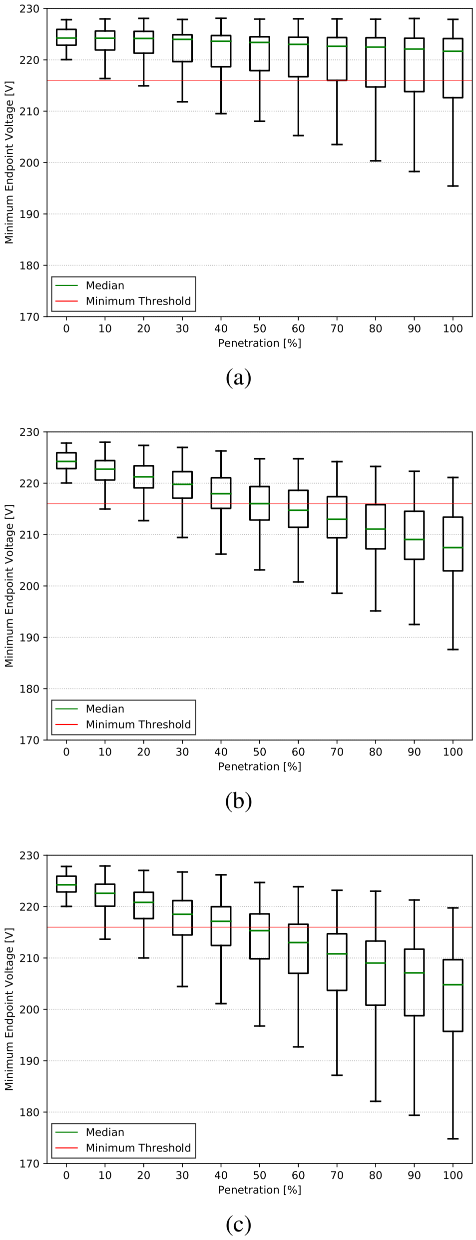


Figure 4.19. Minimum endpoint voltage versus LCT penetration for network 1. (a) EV scenario. (b) HP scenario. (c) Combined scenario.

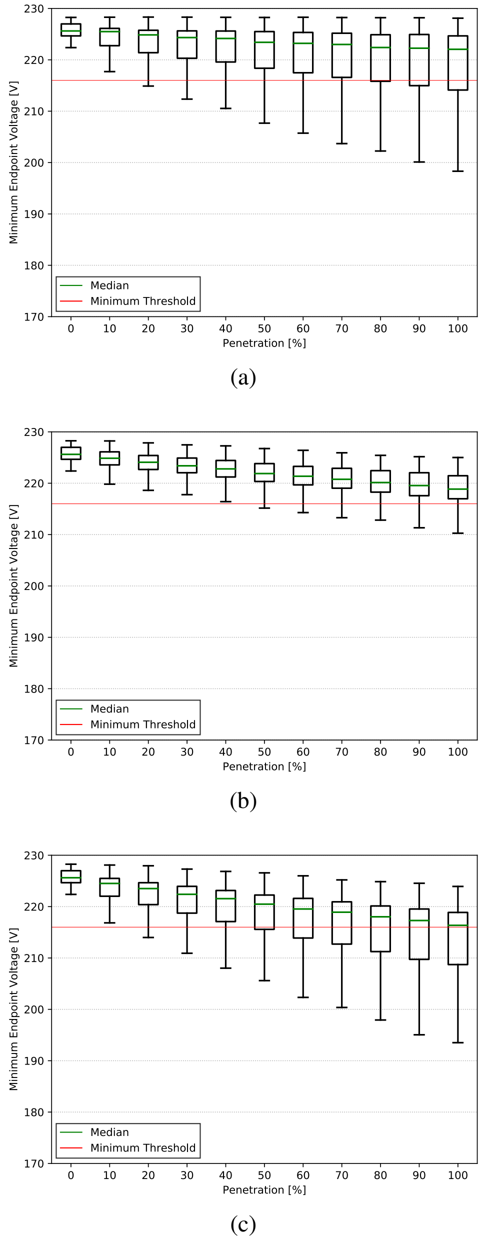


Figure 4.20. Minimum endpoint voltage versus LCT penetration for network 2. (a) EV scenario. (b) HP scenario. (c) Combined scenario.

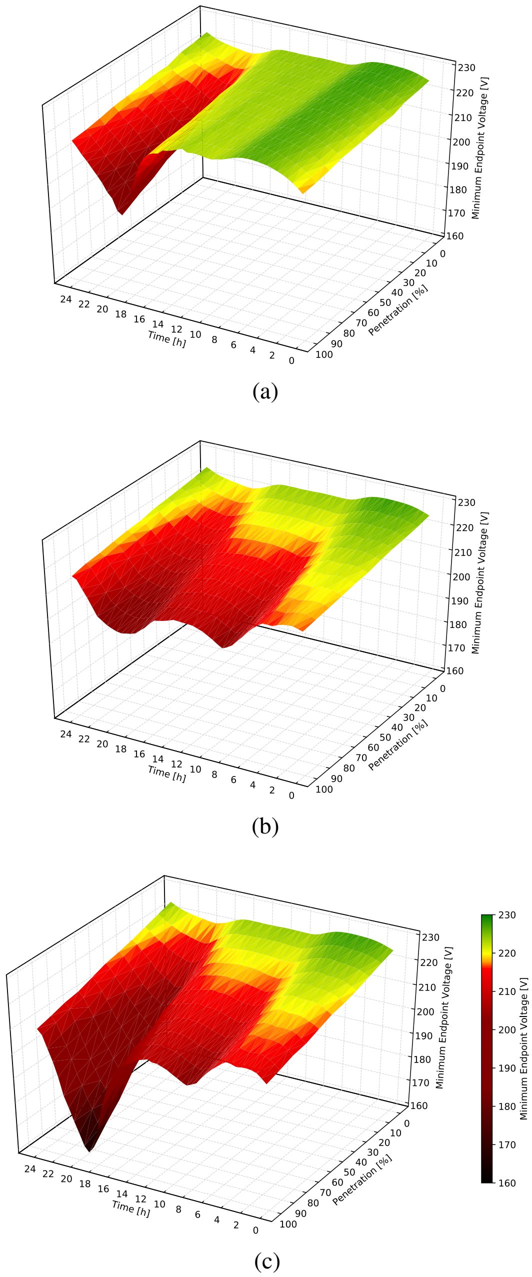


Figure 4.21. Average minimum endpoint voltage versus time versus penetration for network 1. (a) EV scenario. (b) HP scenario. (c) Combined scenario.

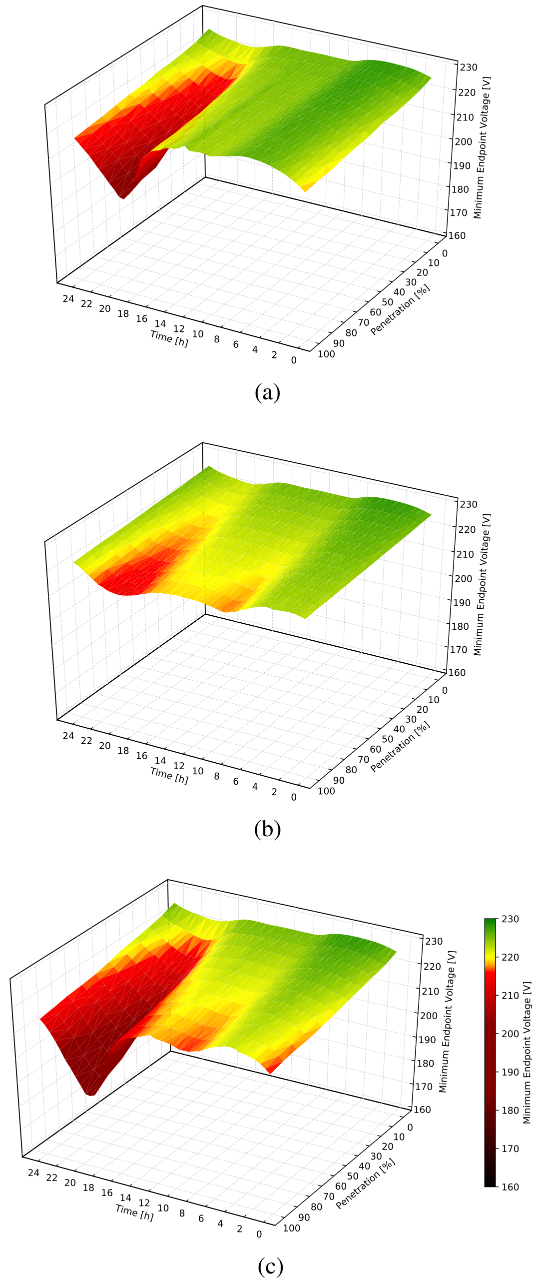
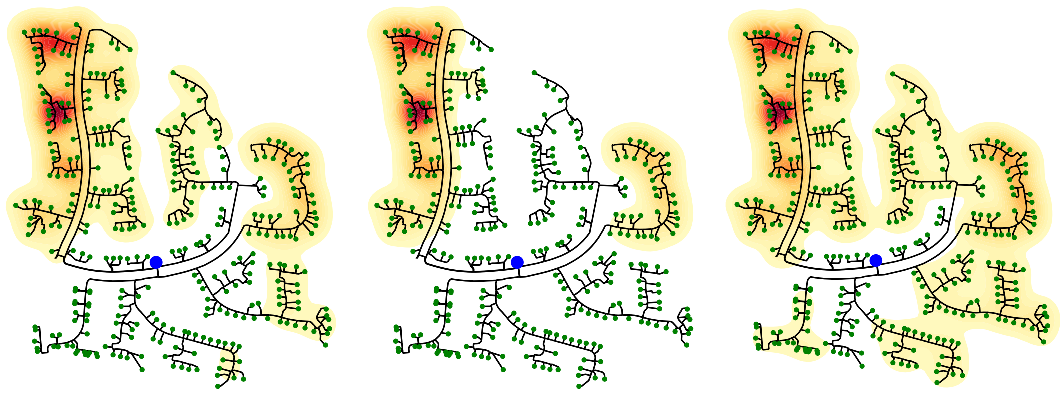


Figure 4.22. Average minimum endpoint voltage versus time versus penetration for network 2. (a) EV scenario. (b) HP scenario. (c) Combined scenario.



(a) (b) (c)

Figure 4.23. Concentration of network buses with voltage violations for network 1. (a) EV scenario. (b) HP scenario. (c) Combined scenario.

(a) (b) (c)

Figure 4.24. Concentration of network buses with voltage violations for network 2. (a) EV scenario. (b) HP scenario. (c) Combined scenario.

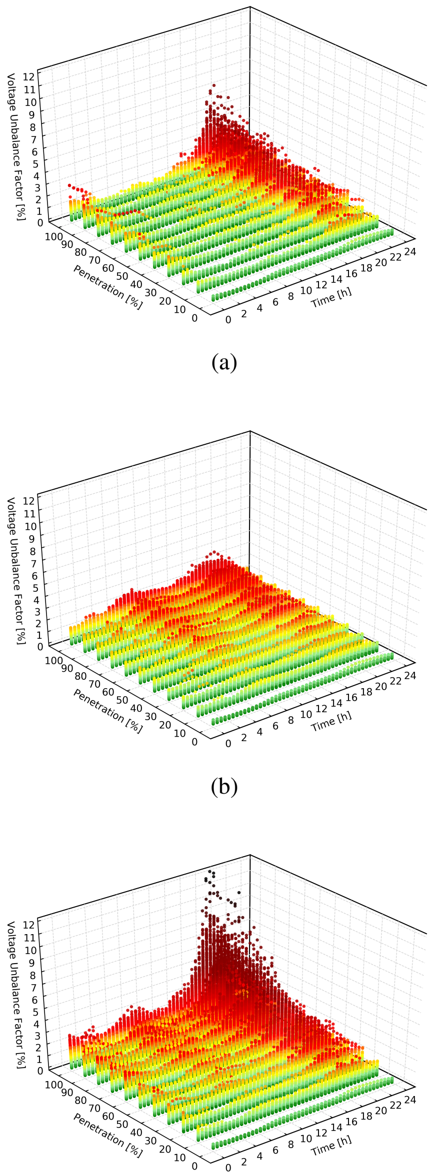
Analysis of cable thermal violations suggests that voltage is likely to be the more problematic of the two for network operators. For the EV scenario on network 1, the percentage of cables in breach of their rating steadily increased from about 1% of cables at around 40% penetration to around 4% at 100% penetration during the evening peak. The HP scenario was less prominent only reaching 2% of all cables at 100% though the early morning demand requirements introduce a minor spike to 1% of cables at 100% penetration. The combined scenario reached a total of 10% of cables for 100% penetration. Analysis of network 2 showed similar behaviour around the evening peak for the EV and combined scenarios although had no thermal violations in the HP scenario. Ultimately these are relatively low values in comparison to the scale of voltage violations and anecdotally, under current practice it would not be uncommon for DNOs to overload cabling and accept the losses and asset degradation consequences. However, this is likely to be challenging in future network operation which requires loss minimisation and improved capacity management for flexible operation.

4.5.2 Phase Unbalance

The phase unbalance results are presented in Figure 4.25 and Figure 4.26 for network 1 and 2 respectively, where the VUF measurement is taken at the LV side of the secondary transformer and at each feeder endpoint. Phase unbalance is often overlooked at these voltages within the literature as many studies e.g. [84], opt to model loads as 3-phase balanced connections due to lack of phasing visibility. However, the results presented indicate that increased consideration regarding HP and EV impact on phase unbalance may be necessary going forward. For both networks in the EV scenario, as penetrations increase, as does the spread of the VUF, particularly, during the evening peak period (this is more prominent on network 1). For the HP scenario on network 1 the VUF increases as a result of increasing penetrations around the early morning and the evening peak though the impact is less prominent than the EV scenario. The combined scenario sees a significant increase in the voltage unbalance factor across the day where the spread increases resulting in an increase in the number of cases exceeding the recommended 2% threshold. For network 2 the uptake of HPs has far less of an impact on the VUF and the spread is more contained across the day. Note that it can be seen from Table 4.1 that network 2 has a more evenly distributed phase allocation than network 1. This emphasises that phase unbalance is likely to be exacerbated in areas where high degrees of unbalance already exist and by the uptake of different LCTs which are diverse in size and use patterns. Also indicating that the heterogeneity in network topology and localisation will have an influence on the scale of this impact.

4.5.3 Hosting Capacity

Figure 4.27 and Figure 4.28 present the results for the hosting capacity assessment where network headroom is compared with LCT penetration for the feeders in networks 1 and 2 for each of the scenarios. The headroom is negative when $S_{f,t}$ has exceeded either S_f^{Tlim} to result in a thermal violation of the feeder head cable or S_f^{Vlim} to move beyond the green region as previously discussed and demonstrated in Figure 4.18. The results emphasise that network



(a)

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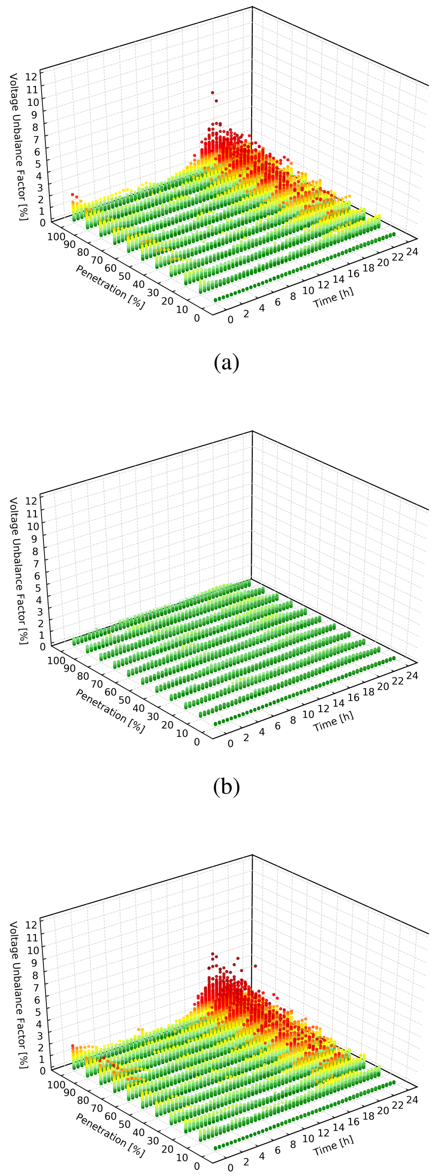
Figure 4.25. Voltage unbalance factor versus time versus penetration for network 1. (a) EV scenario. (b) HP scenario. (c) Combined scenario.



(a)

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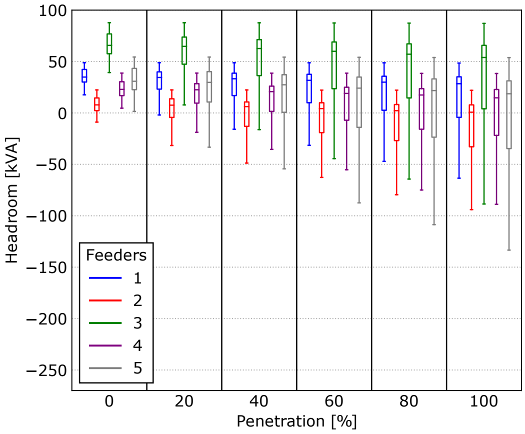
Figure 4.26. Voltage unbalance factor versus time versus penetration for network 2. (a) EV scenario. (b) HP scenario. (c) Combined scenario.

headroom decreases as the penetrations increase across each scenario. The rate of this reduction varies between feeders due to a number of factors including the number of loads connected to the feeder, phase allocation, cable type/rating and feeder length. In the EV scenario the distribution for each feeder remains skewed unlike in the HP scenario as penetrations increase due



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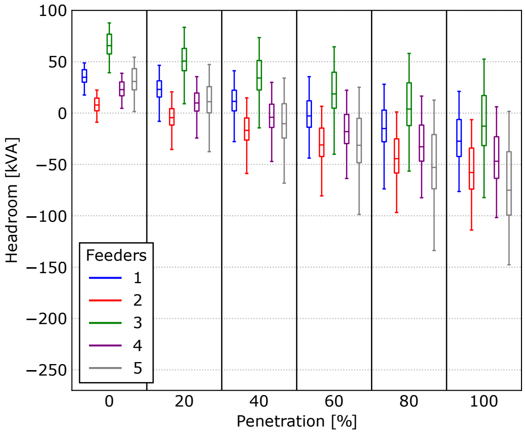

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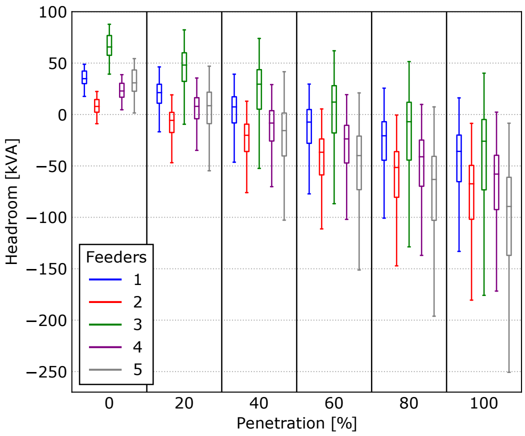

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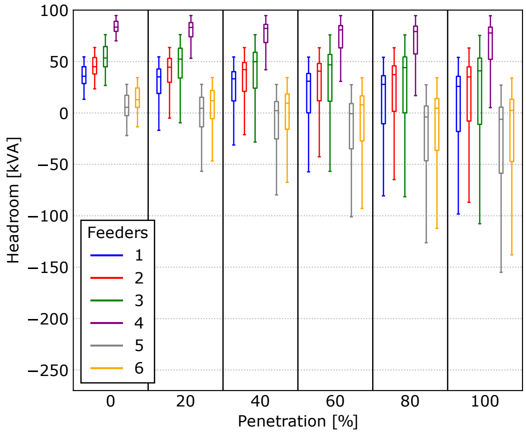
Figure 4.27. Network headroom versus penetration for each feeder in network 1. (a) EV scenario. (b) HP scenario. (c) Combined scenario.



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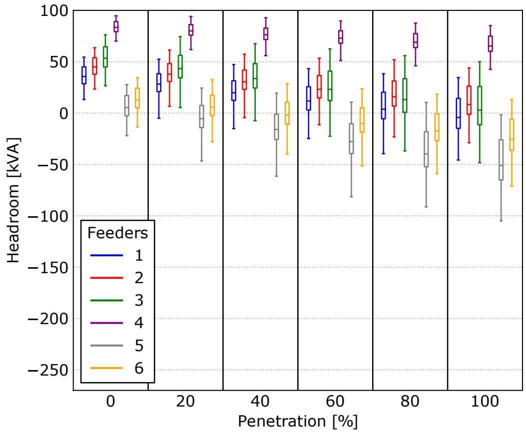

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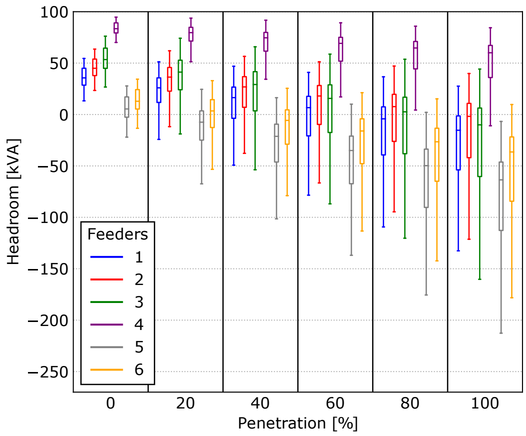

(c)

Figure 4.28. Network headroom versus penetration for each feeder in network 2. (a) EV scenario. (b) HP scenario. (c) Combined scenario.

to the modelled routine dependent EV charging profiles. In the combined scenario, network headroom is significantly reduced in comparison with the individual EV and HP scenarios. The findings also emphasise that to adopt flexible management solutions at an aggregated level, the headroom imbalance between feeders would have to be taken into consideration. LCT management by an aggregator or third party would require full visibility in this eventuality to ensure network limits are respected when managing assets across multiple feeders. The approach used in this work seeks to demonstrate the impact of increasing penetrations and uptake of LCTs with different usage patterns on network headroom. However, to maximise network headroom for flexible applications a more refined approach that accounts for all network cabling and individual phases should be adopted.

4.5.4 Summary

To summarise, the results demonstrate the developed modelling capability through a series of scenarios on two different LV networks. The findings emphasise that the uptake of both EVs and HPs in parallel is expected to cause significant challenges for network operators, particularly as LCT penetrations increase. This is quantified as part of the studies considered. Similar trends exist across the different scenarios in that as LCT penetration levels increase as does the frequency of voltage and thermal violations with voltage violations being the more dominant. The time at which these violations occur is a critical issue that without regulation is subject to individual technology usage patterns. An increase in violations around the traditional evening peak is observed along with an increase in the early morning for the HP scenarios and an increase of the VUF is also observed in certain instances around similar times. The network headroom decreases as penetrations increase. However, this reduction varies non-uniformly across individual feeders. By adopting a localised approach to HP modelling the results shown in this chapter provide the basis for understanding how variations in local heat demand may influence overall HP impacts further demonstrating the value of scalable localised modelling.

4.6 Chapter Summary

This work has developed and demonstrated a novel scalable approach to LV network and LCT impact assessment that can be used to support place-based infrastructure investment decision making. The developed localised LV network modelling methodology can be used to support a wide range of LV network studies from spatial and temporal socio-technical modelling of demand to the development of locally sensitive demand side management techniques through enhanced flexibility quantification. This methodology is guided by high-resolution network information supporting the scalability necessary for network modelling in different geographic regions comprised of diverse local characteristics. This work has evidenced that the method has the capability to reduce the uncertainty surrounding EVs, HPs and demand diversity. This can facilitate the development of techniques that better capture and characterise the impact of local conditions on LCT demand profiles and the subsequent impact on the LV network beyond existing published work in this area. As the developed methodology utilises GIS data and geospatial datasets of varying spatial and temporal resolutions it has limitations that are not uncommon with data-driven modelling approaches, these include data availability, quality and quantity. However, this work has shown that in general these challenges can be managed to support enhanced modelling.

The resulting case study network models are analysed through a localised LV network assessment methodology that accounts for the impact of both EVs and HPs with consideration for the diversity in domestic heat demand. The impact assessment study is used as a means of demonstrating the suitability of the scalable LV network development methodology and the value of place-based LV networks, but also to probe gaps in the literature that relate to electrified heat and transport impact assessments and the approaches taken to model diversity in heat demand at granular resolutions. Multiple assessment metrics are used to demonstrate the modelling approach and to quantify the impact on key network infrastructure (e.g. cables and secondary transformers).

The findings emphasise that the impact from both EVs and HPs is significantly exacerbated when they are adopted in parallel rather than in isolation. The work also identified challenges with unconstrained flexible demand side management approaches, e.g. the potential for flexible EV peak shaving techniques to coincide with early morning space heating demand. This indicates that a mix of LCTs should be considered in the development of such techniques and that existing capacity constraints in addition to local conditions will influence the suitability of flexible network management applications, emphasising that different areas of network may require bespoke solutions.

Chapter 5

Electrified Heat and Transport: Energy Demand Futures, Their Impacts on Distribution Networks, and What It Means for System Flexibility

5.1 Introduction

5.1.1 Motivation

The aim of this chapter is to translate narratives on energy demand futures in heating and transport to impacts on distribution networks, enabling quantification of (i) the impact of these different futures on network infrastructure and (ii) the ability of those demands to act flexibly in supporting the renewables-dominated generation mix necessary to achieve energy system decarbonisation at pace.

Whilst several independently developed pathways have been proposed to meet the UK's legally-binding net-zero GHG emissions target (e.g. [53], [64], [65], [266]), they are generally in agreement on three points. Firstly, that mass electrification of heating and transport demand is the most cost-effective way to shift demand away from fossil fuel use. Secondly, that reducing energy demand – by improving conversion efficiencies and managing the proliferation of high-consumption activities, e.g. flying – will reduce the scale of investment needed for net-zero and de-risk our reliance on technologies that remain to be demonstrated at scale [66]. Thirdly, that time- and space-based flexibility in the electricity demand can avoid or defer the need for network reinforcement and is key to supporting the variable renewables-dominated electricity system needed for decarbonisation [267].

In high-income countries like the UK, energy demand reduction can help to mitigate climate change by reducing the amount of fossil fuels burned [110] whilst simultaneously leading to positive improvements in well-being [268]. These demand reductions can arise from *avoiding* unwanted or unnecessary sources of demand, such as having to drive long distances to access basic services or having to heat poorly-insulated homes; *shifting* demand to a more effective means of energy delivery, such as mode shift from private car to public transport or replacement of a gas boiler by a HP; or by *improving* the efficiency of the devices that convert final energy into its useful form, such as the substitution of ICEVs for electric cars or an improvement in boiler efficiency. This *Avoid-Shift-Improve* hierarchy of energy demand reduction, as detailed in [269], can be used to quantify routes to energy demand reduction as a means of climate change mitigation and well-being improvement.

Whilst recognising that there has been a wealth of research on quantifying the impacts of demand electrification on electricity systems, as previously evidenced through review of the literature in Section 3.2 and Section 4.2, there remains a knowledge gap in how different futures in energy demand will impact network infrastructure and subsequently, inform the value proposition for local flexibility. Thus, focusing on electrification of domestic heat and transport, this chapter will address this gap to provide stakeholders with better understanding of the impacts different futures in energy demand may have on the electricity system and its operation.

5.1.2 Contribution

The key contribution of this chapter, as summarised by Figure 5.1, is the development of a method to translate narratives on energy demand futures in heating and transport to impacts on local electricity systems, enabling quantification of the stress placed on key infrastructure and the ability of those demands to act 'flexibly' in supporting the renewables-dominated generation mix necessary to achieve energy system decarbonisation at pace. The novelty of the developed methodology stems from the following:

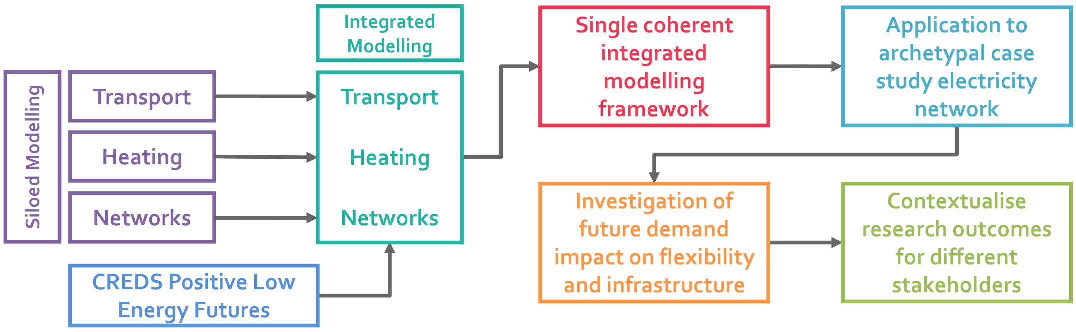

Figure 5.1. High-level overview of the methodology developed to investigate the impact of future demand scenarios on flexibility and infrastructure.

- Existing demand scenarios, as developed by the CREDS in their PLEFs [110], are used to drive (i) *spatially* explicit modelling of the uptake of electrified transport and heating; and (ii) *temporally* explicit modelling of the electricity demand of these technologies for a local geography.

- A model of a real electricity distribution network that serves households in the local geography is used as the basis to examine the impacts of varying demand scenarios on electricity system infrastructure. An unbalanced OPF model of a three-phase electricity network with realistic distributions of loading among the three phases is used to investigate the impact of these demand scenarios on the potential of flexibility in electricity demand.

- Results are reported in terms of loading of that network under the different scenarios, with and without flexible demand (from EVs). These results are used as evidence of the potential benefits of policies that support energy demand reduction and flexibility.

The remainder of the chapter is organised as follows. Section 5.2 provides a review of the related literature by building on the work presented in the previous chapters. Section 5.3 describes the CREDS future energy demand scenarios. Section 5.4 describes the spatial uptake modelling for both heat and transport. Section 5.5 describes the temporal modelling for both heat and transport. Section 5.6 describes the distribution network and domestic demand modelling. Section 5.7 describes the unbalanced OPF and flexibility modelling. Section 5.8 describes the case study area, the case studies and their modelling methods. Section 5.9 presents the results from the study. Section 5.10 discusses the results in the context of future implications for energy infrastructure and policy. Section 5.11 presents a summary of the work described in this chapter. Note that several of these sections refer to modelling carried out and described in previous chapters. In this chapter they are briefly reintroduced to remind the reader and to specify the relevance to this work.

5.2 Literature Review

Two observable trends on energy demand are that:

1. **Growth in wealth leads to growth in demand for energy services**: over the time period 1971-2018, each percentage point of growth in global gross domestic product led to an increase in 0.68% of energy demand [270];

2. **Improvements in conversion efficiencies alone do not lead to reductions in energy consumption**: the evidence for this has been consistently revisited in the literature as an application of the Jevons paradox [271]–[273].

There is a growing body of literature on the potential for energy demand reduction to contribute towards climate ambitions, and this is generally presented not only as a vital part of climate mitigation strategies. Grubler et al. present a global energy consumption scenario whereby total demand is reduced by 40% by 2050 relative to today's levels [274]. The IEA's pathway to global net-zero emissions by 2050 stresses the importance of measures to limit energy demand, including behavioural changes and resource efficiency, stating that global energy demand can be reduced by approx. 90% versus the counterfactual baseline by 2050 [275]. Van Vuuren et al. use integrated assessment models to construct alternative models to meeting the 1.5°C target of the Paris Agreement and, in doing so, support wide-ranging reductions in energy demand from switches in mobility to improvements in building thermal efficiency [276].

Increasingly, studies frame the contribution of energy demand reduction in meeting climate targets at the national – rather than international – level. In a UK context, Barrett et al. use a suite of whole energy systems models and scenario development through expert stakeholder engagement to investigate the potential role of energy demand reduction in supporting and 'de-risking' pathways to net-zero emissions [110]. By examining trade-offs between varying levels of technology adoption and behavioural change, they conclude that energy demand can be reduced by up to 52% by 2050, compared to 2020 levels, without compromising on citizens' quality of life. The CCC has a significant focus on energy demand reduction in their analysis of possible pathways to the UK meeting its net-zero target [53]. In the CCC's 'balanced' pathway to net-zero, which represents the mid-point between technology change and behaviour change, there is significant focus on the contribution of energy demand reduction both through efficiency improvements (e.g. increased rates of retrofitting leading to a 12% reduction in domestic heating energy demand) and behaviour change (e.g. reductions in per-capita car kilometres by 17% and per-capita meat consumption by 34%). Brand et al. [277] explored the roles of lifestyle change and socio-cultural norms versus electrification and phasing out of conventional fossil fuel vehicles, suggesting that lifestyle change alone can have a comparable and earlier effect on transport carbon and air quality emissions than a transition to EVs with no lifestyle change. Yet, both strategies have limits to meeting legislated carbon budgets, which may only be achieved with a combined strategy of radical change in travel patterns, mode and vehicle choice, vehicle occupancy and on-road driving behaviour with high electrification and earlier-than-planned phasing out of conventional fossil fuel vehicles. However, while the study in [277] was carried out at a national level with zero spatial detail, these measures can vary significantly by local area and so there is a need to examine the effects of these policies at finer geographical and political boundaries.

As identified in previous chapters, there is a largely separate body of literature that has looked to quantify the impacts of the electrification of heat and transport on electricity system infrastructure. These studies typically generate temporal demand profiles based on the electrification of energy services such as heat and transport and superimpose these profiles onto a model of a distribution network[13]. These works tend to focus on the electrification of one particular energy service (generally heat or transport), studies that focus on the aggregate effects of combined heat and transport electrification on network infrastructure are less commonplace.

The potential for both EVs and HPs to act as providers of system flexibility in the context of a high-renewables power system with embedded communications has been well-researched. Venegas et al. [106] identify and analyse potential frameworks for the active integration of EVs

[13]The literature tends to focus on the impact of electrification of heat and transport on distribution networks. Crozier et al. [278] present analyses of the impacts on distribution and transmission infrastructure using a common analysis method and find that distribution networks are at higher risk of having their operational limits compromised as a result of demand growth.

to the power system at various temporal and spatial scales, concluding that there is significant value in flexibility of distributed demand at the scale of distribution systems. Backe et al. [107] present a local ('community') energy system model to assess the potential to use HP and EV flexibility to manage variance in demand and supply in the Norwegian power system. The authors estimate that by using HPs and EVs as providers of flexibility, the average European electricity cost could reduce by 3% and the expansion rate of the transmission network could reduce by 0.4%. Salpakari et al. [108] present a similar study to that in [107], but rather than the objective function of the optimisation being over a wide area, a control model is presented to optimise the provision of flexibility from EVs and HPs at the scale of a microgrid. On the basis of a single house, the study suggests that a consumer can save 33% on energy costs through the optimal coordination of flexibility, given their energy demand requirements. Aside from saving costs and quantifying the level of network reinforcement required, studies have shown that flexibility can reduce the emissions intensity of electricity delivered in a region, as demand can be scheduled for periods of high renewable availability. For instance, Gunkel et al. [109] present a modelling framework to compare the total carbon emissions resulting from a power system spanning much of Northern and Central Europe before and after the introduction of flexibility from EVs. They estimate that between 2020 and 2050, the addition of flexibility from EVs can save up to 23 $MtCO_2e$ without any changes to the generation mix: in context, that is around 4% of the UK's current economy-wide emissions.

Whilst there is demonstrably a considerable body of literature on the impacts of electrification on electricity system infrastructure and potential of demand flexibility, none of the above cited studies consider the future evolution of energy service demand as a result of shifting societies, evolving technologies and policies that actively support energy demand reduction in the name of climate change mitigation and promotion of human well-being. This is identified as a considerable research gap; to the author's knowledge, there has been no work on linking pathways in energy demand futures – such as those presented in [110] – to the potential impacts on infrastructure and the value proposition of flexibility. Thus, the work of this chapter will translate narratives on energy demand futures in heating and transport to impacts on local electricity systems, enabling quantification of the stress placed on key infrastructure and the ability of those demands to act 'flexibly' in supporting the renewables-dominated generation mix necessary to achieve energy system decarbonisation at pace.

5.3 Energy Demand Futures: Re-Introducing the CREDS Positive Low Energy Futures

CREDS was established as part of the UK Research and Innovation's Energy Programme in April 2018, to "*make the UK a leader in understanding the changes in energy demand needed for the transition to a secure and affordable, net-zero society*" [279]. This was based on the premise that the ongoing displacement of fossil fuels is not proceeding at a rate that aligns with the UK's 2035 emission reduction goal. Therefore, in order to ensure that reductions in fossil fuel usage occur at the necessary pace to achieve the UK's climate objectives, there is a need for both an acceleration in the deployment of renewable energy sources and for rapid substantial reductions in energy demand. With this, the CREDS PLEFs (shown in Table 5.1) that represent detailed energy demand scenarios were developed as part of a significant programme of research aimed at quantifying the potential of demand reduction policies to assist the realisation of the net-zero GHG emissions target in the UK. Unlike other future scenarios as noted in Section 1.1.3, the PLEFs are unique in that they are solely focused on the potential contribution of energy demand reduction, this makes the PLEFs the most comprehensive set of scenarios currently available that inform on the future of energy demand in the UK.

The PLEFs were developed by compiling narratives written by various experts across a range of fields in industry, academia, policy and civil society. These narratives are underpinned by seven observable underlying trends in wider society that have impacted energy demand to date, and/or are likely to do so in the time horizon under consideration (to 2050). The seven observable trends are i) digitalisation, ii) sharing and circular economies, iii) energy efficiency, iv) healthy societies, v) environmental awareness, vi) globalisation and vii) work and automation. Figure 5.2 provides a visual representation of how these trends feed into the modelling approach employed to develop the PLEF scenarios. A full description of the scenario development process and full details of the sectoral implications of the scenarios are available in the 2021 CREDS report [279].

In this chapter, the PLEFs are taken as a starting point and used to develop scenarios for technology uptake (Section 5.4) and energy service demand (Section 5.5) for both heating and transport.

Table 5.1. Summaries of CREDS Positive Low Energy Futures (reproduced from [110])

Scenario	Description
Ignore	Identifies levels of energy demand up to 2050 assuming only existing UK government climate policy instruments are implemented (as of 2018). This includes existing policy for delivery of emission reductions but not climate targets or ambition.
Steer	Adopts the more ambitious legislated target of net-zero GHG emissions by 2050 but falls just short of meeting it. Uses the same energy service-demand projections as the Ignore scenario but implements a wide range of energy efficiency options.
Shift	Adopts the net-zero GHG emissions target. Significant shift in the attention given to energy demand strategies providing an ambitious programme of interventions across the whole economy describing what could possibly be achieved with currently available technologies under current social and political framings.
Transform	Adopts the net-zero GHG emissions target. Considers transformative change in technologies, social practices, infrastructure and institutions to deliver both reductions in energy but also numerous co-benefits such as health, improved local environments, improved work practices, reduced investment needs, and lower cumulative GHG emissions.

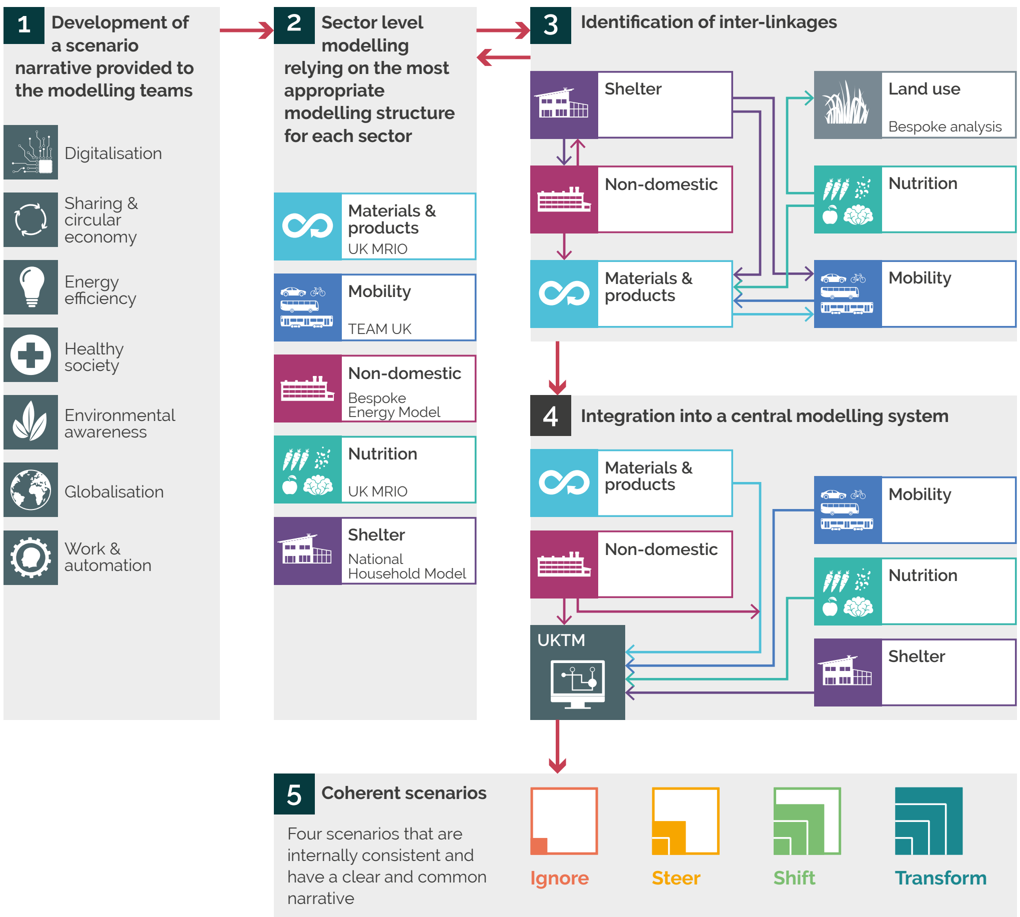

Figure 5.2. Overview of the CREDS positive low energy future scenario development framework [279].

5.4 Spatial Technology Uptake Modelling in Heat and Transport

This section describes the uptake modelling for both heat and transport and how, from this, future technology penetration levels for heating and transport are obtained for each of the PLEFs.

5.4.1 Heat: Technology Uptake Model and Application of PLEFs

This section describes the heat technology uptake modelling approach taken and the application of the PLEFs to the technology uptake model.

Prevalent options for exploring energy transitions have limited treatment of societal actors and socio-political dynamics, and are typically poor at representing the co-evolving nature of society and technology, tending to overlook spatial and within-sector detail [280], [281]. Therefore, a spatially explicit, place-based, agent-based[14] heating technology diffusion modelling approach was used in this chapter to address these concerns. Whilst detailed descriptions of the modelling approach are provided in [282] and [73], a brief overview is presented here. The high-level agent investment decision process, and thus the abstract modelling workflow, is illustrated in Figure 5.3. The modelling workflow repeats on an annual basis over the modelling period for all households that are ‘triggered’ to undergo the investment process.

The agent-based model (ABM) considers the point at which existing owner-occupied households choose between either upgrading their existing heating system to the same technology with modern performance parameters or retrofitting a low-carbon heating option. A heterogeneous set of agents are modelled with bounded rationality, and a high degree of spatial and within-sector detail is obtained while having national coverage. This allows both the impact of different incentives and regulations on heating technology investment decisions to be explored at local, regional and national scales, and also allows for strategic last-mile energy infrastructure planning activities to capture projected heat system change. The model is calibrated and validated against actual heating technology uptake statistics.

[14] In agent-based modelling, a collection of autonomous decision making entities called agents are used to model a system. These entities follow a predefined set of rules, interacting with each other and their dynamic environment [282]. For this work, the ‘agents’ depict households that have the following attributes: output area, residential area-based classification, tenure type, behaviour classification, heating system size, annual heat demand, existing heating option, ground-source heat pump availability and hydrogen heating availability. The reader is referred to [282] for further information on these attributes.

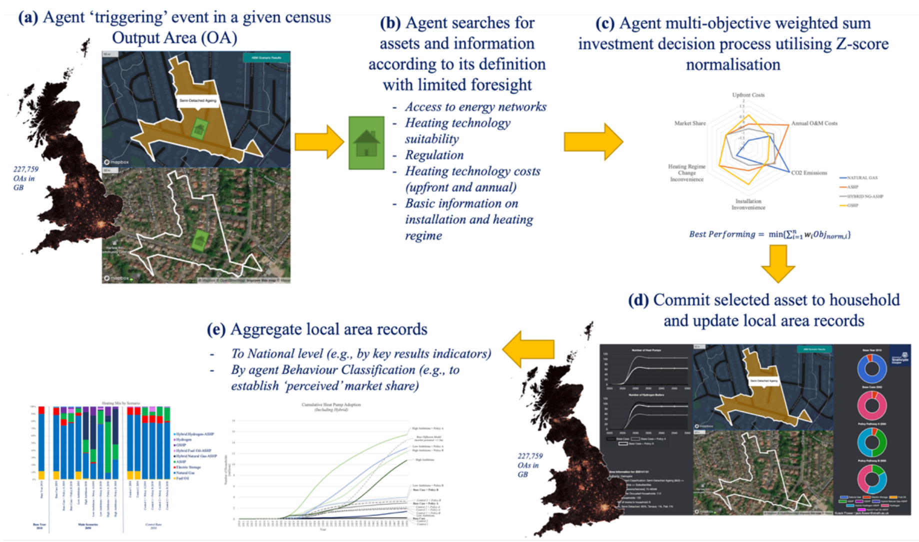

Figure 5.3. Schematic highlighting agent-based heating technology uptake model used for this work [282].

The below offers a brief explanation of the primary components of the modelling process (points 'a' to 'e' as shown in Figure 5.3).

a) An agent is considered 'triggered' when their heating system becomes faulty or inefficient to run. The annual replacement rate is then used to determine the rate of households that are triggered to undergo the investment process in local areas across Britain. This metric broadly represents the actual sales of heating technologies in Britain each year and is further explained in [282]. This simplification eliminates the need to determine the exact age of every installed heating option at the model base year and beyond. Agents are also triggered when a local gas conversion project occurs in their area, regardless of the age or condition of their current natural gas-fired heating system.

b) A 'triggered' agent then starts searching for assets and information based on its definition, this search occurs with limited foresight of future events. The effectiveness of this process is significantly influenced by local area attributes, including access to energy networks, and it relies on scenario-specific details, such as pertinent national and local policies.

c) Within the search space of the agent, the assets undergo evaluation based on criteria unique to that agent. This evaluation employs a multi-objective weighted sum method, wherein decision weights tailored to each agent and specific objectives are used. These

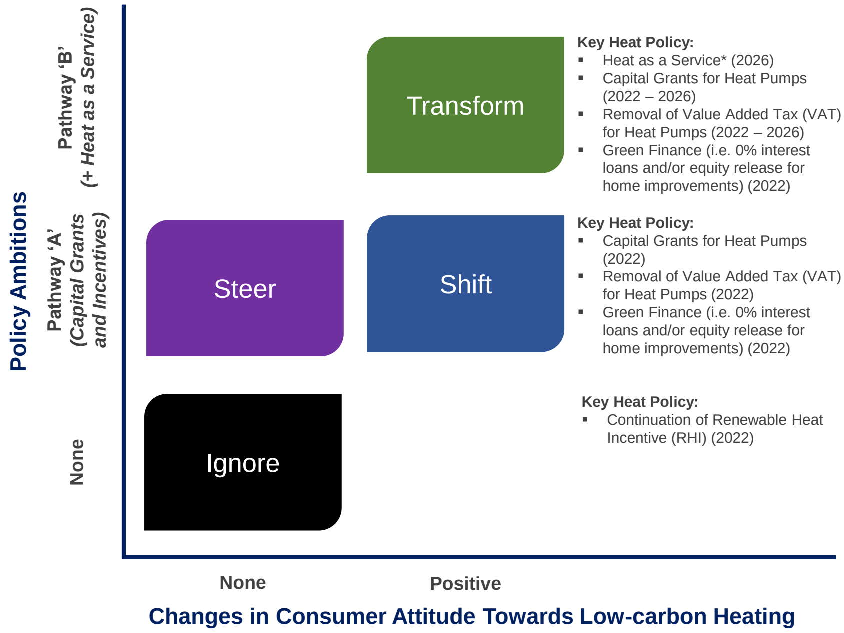

Figure 5.4. Scenario matrix showing changes in consumer attitudes (horizontal axis) and policy ambitions (vertical axis).

are calibrated using historical data on the adoption of heating technologies to simulate the investment choices of different consumer archetypes. The investment process is strongly influenced by factors that are specific to the agent at a particular point in time, such as the heating needs of the household and the attributes of the assets available for selection within the agent's search area.

d) After the agent has made the investment decision, the chosen asset is allocated to the household, and the local area records are subsequently revised and updated.

e) Information from local area records is then consolidated, both at a national level (e.g. incorporating key performance indicators like yearly emissions, technology adoption data, and government expenditure) and across different agent categories (e.g. to determine the 'perceived market share' variable employed in the investment decision process used in (c), which captures investment behavioural patterns).

For this work, the PLEFs (Table 5.1) were input into the heating technology uptake model as detailed in Figure 5.4.

5.4.2 Transport: Technology Uptake Model and Application of PLEFs

This section describes the high-resolution EV uptake model used in this work and the application of the PLEFs to this model. The model combines an adaptation of the vehicle stock model (VSM) car module in the Transport Energy Air pollution Model (TEAM), an existing transport-energy systems model originally presented in [283], with a car ownership prediction model based on artificial neural networks originally presented in [284].

TEAM is a strategic transport, energy, emissions and environmental impacts systems model, covering a range of transport-energy-environment issues from socio-economic and policy influences on energy demand reduction through to lifecycle carbon and local air pollutant emissions and external costs. Based on its precursor model, the UK Transport Carbon Model [285], TEAM has been developed over the last decade to undertake policy analysis (e.g. [286], which examined the implications of the EU 'Dieselgate' scandal in the UK by exploring unaccounted and future air pollutant emissions and energy use for Britain's cars, and [287], which explored the energy and emissions implications of the UK government's 2018 Road to Zero strategy [202]) and exploration of possible future transport pathways [277]. Figure 5.5 provides an overview of the different components within TEAM.

TEAM was used for the mobility sector level modelling in developing the PLEFs. Therefore, for consistency with the CREDS scenario development framework, TEAM is considered to be more applicable for use in this work in comparison with other alternative transport-energy-environment models which are also typically proprietary and lack the detail to simulate policy decisions against a backdrop of contextual changes. The part of TEAM used for this work was the car choice module of the VSM, which projects the disaggregation of the car market (for both private and company/fleet owners) by technology and by year, taking into account established scrappage rates, vehicle buyer behaviour, consumer segmentation as well as market response to vehicles attributes, price signals and incentives (financial and otherwise). It is beyond the scope of this work to describe the VSM in detail; the reader is referred to [283] and [288] for full details. The car module of the TEAM VSM was translated into the Python for use in this work [289].

The *Spatial Temporal Engine for Vehicle Fleet Evolution* (STEVE) combines the car stock model of TEAM (as described above) with a spatial car ownership prediction model as a way

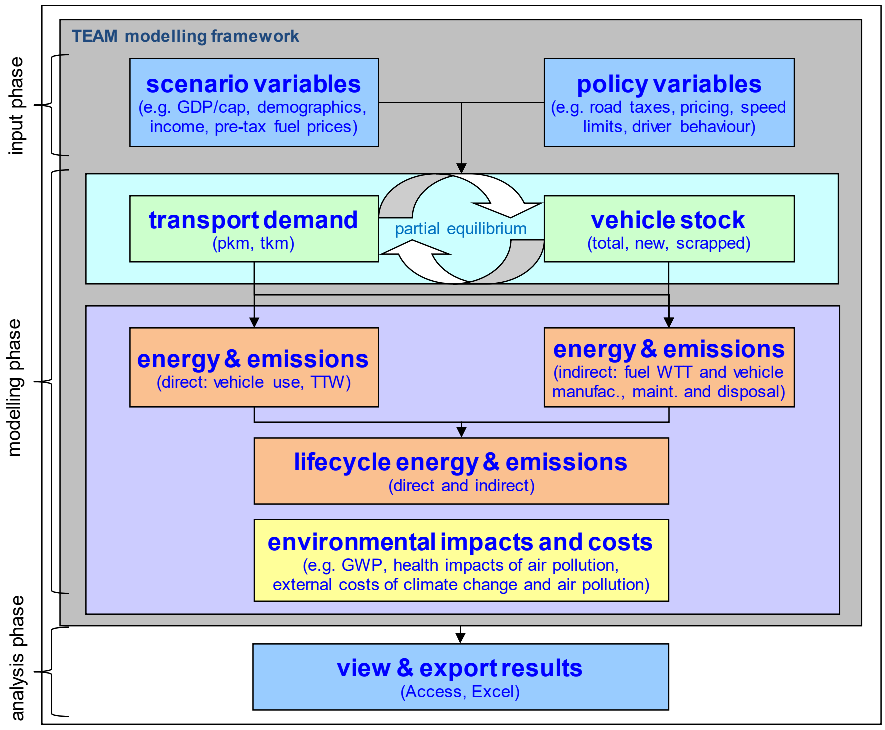

Figure 5.5. Components of the Transport Energy Air pollution Model [288].

of providing insights on the spatial variation in electricity demand from EVs. The car ownership prediction model was developed based on artificial neural networks that use historical car registration data and projections of key socio-economic indicators available at the local level, including household disposable income, economic activity, demographic and population density. The model is described in detail in [284]; demonstration of the model's ability to predict the number of cars for each Scottish data zone is shown in Figure 5.6.

In this work, for application of the PLEFs to the EV uptake modelling, STEVE was used to simulate possible futures for transport electrification at a local level. Firstly, the spatial regression approach described previously was used to characterise the business-as-usual evolution of the UK car fleet by lower super output area, UK Census geographies containing on average 300-700 households, based on forecasted changes in independent variables that have been consistently shown to influence car ownership [290]. This business-as-usual trajectory is then taken to represent the Ignore and Steer scenarios; they are altered to produce UK car fleet trajectories for the Shift and Transform scenarios using the uptake scenario results in the PLEFs [279]. Secondly, the set of new cars – driven by an increasing 'demand' for private cars, as well as the

Figure 5.6. Comparison of predicted and actual number of cars by data zone, Scotland, with detail shown for Glasgow region [284].

scrappage of old ones – is disaggregated into a set of technologies (covering size, powertrain, fuel, engine type and capacity) according to a discrete choice modelling framework (within the VSM), in which vehicle technology uptake is modelled amongst a heterogeneous consumer market represented by four private and two fleet UK market segments. For full details on the discrete choice model used in STEVE, the reader is referred to [283]. The PLEFs are then input as a set of modellable levers into STEVE which covers, amongst other things, consumer awareness, access to charging, subsidies of technologies, sale bans of certain technologies (e.g. the ban of sale of internal combustion vehicles after a certain date), and fuel taxation. For full details on the levers as applied to STEVE, the reader is referred to [279]. From this, the rate of EV uptake for different local areas is obtained which supports a more representative network impact assessment in comparison with using simple fixed uptake assumptions that fail to consider local attributes.

Figure 5.7 provides an overview of how the different modelling capabilities described above are used in this work to derive EV uptake for a specified location in Scotland for each of the CREDS PLEFs.

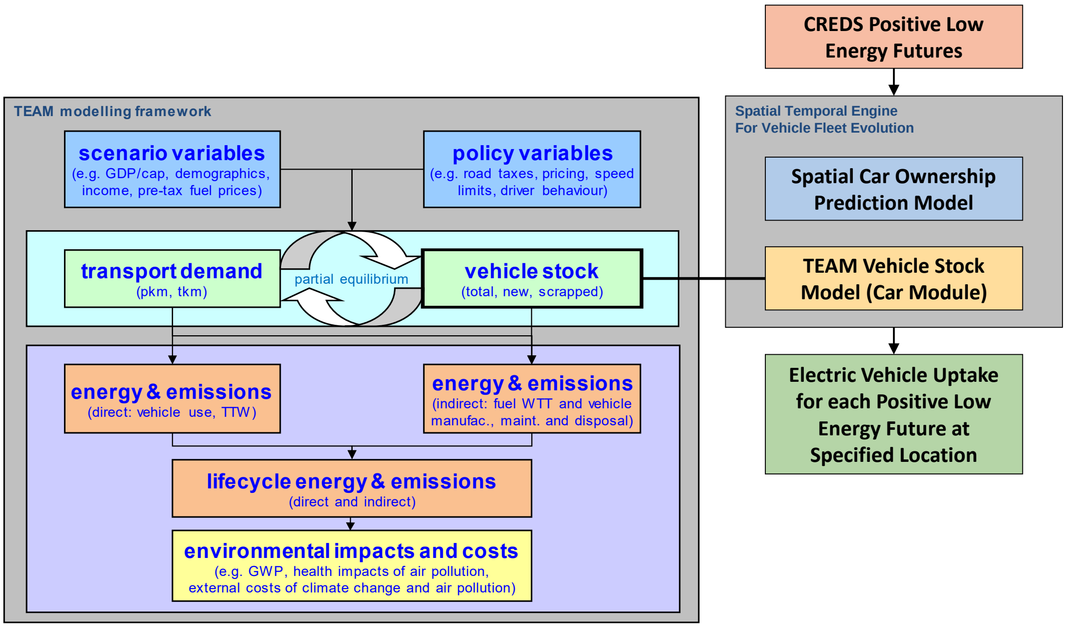

Figure 5.7. Overview of the spatially explicit EV uptake modelling process.

5.5 Temporal Energy Demand Modelling in Heat and Transport

This section describes the temporal demand modelling approaches for both heat and transport, and where applicable describes how the influence of the different PLEF scenarios are captured in the modelling. From this, daily temporal demand profiles for the heating and transport technologies are obtained.

5.5.1 Heat Modelling

This section describes the approach taken to capture the changes in future heating demand and to model temporal heat demand.

5.5.1.1 Electricity Demand from Heat Pumps

The method developed in Chapter 3 of this thesis is used to model household HP demand. In Section 3.3.2.2, the relationship between the SIMD and gas consumption is explored and from this, representative gas consumption CDFs for each individual SIMD decile are derived. Similarly with Chapter 3 and Chapter 4, the *Heat Demand Magnitude Localisation Model* and *Electrical Heat Demand Shape Model* are then used. These are combined to construct locally sensitive half-hourly electrical heat demand profiles where the developed relationships between gas demand and social deprivation are used as inputs to the modelling. A brief description of each model component has been provided in Section 3.4.2. For detailed descriptions the reader is referred to [232].

5.5.1.2 Electricity Demand from Electric Storage Heaters

As identified in [93], the smart meter data recorded during the LCL trial contained households that had a high overnight demand which can be attributed to storage heating. These households tend to have a large spike in demand at midnight which is consistent with storage heater operation on an Economy 7 tariff [124]. These profiles have been used to represent ESHs in this work where a similar process is used as with domestic demand (described in Section 3.3.2.1) to create a bank of half-hourly daily profiles representing households that have an ESH in addition to generic domestic demand, allowing for stochastic iterative sampling and assignment to individual consumers. These profiles are separated from those with no ESH demand to prevent heat demand being added twice if and when adding HPs. Note that any household demand profile with a spike in demand greater than 6 kW at midnight and lasting longer than one hour was considered to have an ESH. Standard household appliances as represented in the CREST demand model [291] are typically lower than 6 kW with the exception of a 9 kW electric shower, though it is assumed that average shower duration would typically be less than one hour.

5.5.1.3 Application of PLEFs to Annual Heat Demand

Work by Canet et al. [292] is used to arrive at plausible percentage reductions in annual household heat demands that align with the PLEF narratives. More specifically, Canet et al. conduct statistical analysis using Energy Performance Certificates (EPCs) for England and Wales, where they generate annual heat demand reduction potentials given the measures listed on EPCs and other factors, which are well aligned to the drivers of heat demand reductions in [279]. The dataset in [292] is first filtered to obtain the same classification of dwellings as that found in the area of interest, and the range of heat demand reduction potentials for the remaining dwellings are then characterised. Given that the potential reductions as in [292] are based on meeting the UK's 2050 net-zero target, they are scaled back to 2030 based on the same rates of progress in the National Household Model[15] as used in the CREDS work [279].

5.5.2 Transport Modelling

This section describes the approach taken to capture the changes in future transport demand and to model temporal transport demand.

5.5.2.1 Electric Vehicle Charging Model

Opportunities for EV owners to plug in their vehicles for charging depend on when they start and finish their journeys and what the destinations are. These journeys also dictate what the minimum amount of energy in each charge will be. This then determines the temporal and spatial pattern of demand for electricity for EV charging, necessary for the modelling of future electricity demand. Therefore, to account for EV utilisation by domestic consumers as part of the modelling work in this chapter, an EV charge event model originally presented in [192] is used. The model, a heuristic used to generate EV charge events from trip data (such as those from the UK NTS), has been used in a number of studies [89], [138], [193] and in Chapter 3 and Chapter 4. Trip data from the 2019 UK NTS is similarly used for the work of this chapter, which contains 210,717 car-based trips split between 13,863 cars. Accordingly, this work assumes that future EV drivers – at a baseline, before the application of the PLEFs – will use their cars in the same way as combustion engine car drivers, before the Covid-19 pandemic [294].

5.5.2.2 Application of PLEFs to Electric Vehicle Charging

The EV charging schedules resulting from the heuristic described above are modified by a stochastic process of adjustment according to a consolidated set of changes in the number of trips and the trip distance for each relevant PLEF scenario in Table 5.2[16]. This applies specifically to the Shift and Transform scenarios, which unlike Ignore and Steer, consider policies focused on changes in behaviour in addition to policies focused on technology uptake. These

[15] The National Household Model is an open-source analytical tool that was developed to project the effects of policy and other legislative changes on the energy and emissions of the UK domestic housing stock [293]. It is primarily used to inform on policy decisions and to ensure that government actions are evidence-based. The model can provide insights into how different economic, social, and policy changes might affect households across the county and is also a useful tool for making informed decisions about policies related to taxation, benefits, and other aspects of public policy.

[16] Local leisure = social entertainment; sports; visiting friends and relatives elsewhere. Distance leisure = visiting friends and relatives at home; holiday; day-trip.

consolidated changes are the net changes for each scenario where there are several factors that influence – both positively and negatively – each trip type. For example, four trends impacting the number of commuting trips for each person are identified as: reduction due to more people in retirement; reduction due to increased teleworking; increase due to gig and service economy; reduction due to 4-day working week. Table 5.2 represents the consolidation of the impacts of these trends for each trip type. The full details for which are available in [279].

Table 5.2. Change in number of trips and trip distance in 2030 and 2050 for Shift and Transform scenarios relative to 2019 baseline (1.0 = no change)

	Shift				**Transform**			
	No. Trips		**Trip Dist.**		**No. Trips**		**Trip Dist.**	
Trip Type	2030	2050	2030	2050	2030	2050	2030	2050
Commuting	1.01	1.03	0.92	0.75	0.88	0.815	0.85	0.65
Business	0.9	0.75	0.95	0.85	0.85	0.65	0.9	0.83
School travel	0.95	0.95	0.9	0.85	0.95	0.95	0.85	0.75
Shopping	0.8	0.7	0.9	0.9	0.7	0.6	0.8	0.85
Personal business	0.95	0.95	0.95	0.9	0.9	0.9	0.9	0.85
Local leisure	1.15	1.25	0.95	0.9	1.15	1.3	0.9	0.85
Distance leisure	1.1	1.2	0.95	0.9	1.15	1.22	0.95	0.9

To apply these consolidated changes to the NTS travel diaries, the following steps were taken.

- For the **number of trips**:

    1. The set of car-based NTS travel diaries were split into 'high-travel' and 'low-travel' diaries according to whether they took a car-based trip on all 7 days ('high-travel') or not ('low-travel'). This was to allow duplicate trips to be added in a way that did not result in overlapping trips (by adding them on days where there were no trips taken, to the 'low-travel' diaries).

    2. If the number of trips of a certain type (e.g. school travel) were to be *increased*, then a random set (of size corresponding to that proportional increase) of trips of that type would be duplicated (including return trips) on days where travel did not take place. This would be done for the 'low-travel' diaries.

    3. If the number of trips of a certain type were to be *decreased*, then a random set (of size corresponding to that proportional decrease) of trips of that type would be removed (including their corresponding return trip, if it existed). This would be

done for the ‘high-travel’ diaries.

- For the **trip distance**, if the distance of a trip of a certain type is to be changed, then all trips of that type have their distance (and thus energy expenditure) adjusted accordingly.

The resulting modified NTS travel diaries were then processed through the aforementioned heuristic to produce charging schedules for use in the EV demand flexibility modelling (Section 5.7.2).

5.6 Distribution Network and Domestic Demand Modelling

5.6.1 Distribution Network Modelling

The approach used in this work to model a ‘real’ electricity network for a given area is described in Chapter 4. It makes use of network GIS data that includes both spatial and technical information pertaining to network infrastructure installed across the north of Scotland.

The method allows for place-based modelling by integrating the network GIS data with external spatially linked datasets. These datasets can provide valuable insight into the characteristics of specific areas and support detailed modelling of both electricity networks and local energy demand.

5.6.2 Domestic Demand Modelling

For domestic demand modelling, the approach described in Section 3.3.2.1 and Section 4.3.4 is used where a bank of half-hourly daily winter profiles for each Acorn category is created from the LCL project allowing for stochastic iterative sampling and assignment to individual consumers. This considers consumers for SIMD decile 9-10 to be ‘Affluent’, 4-8 to be ‘Comfortable’ and 1-3 to be ‘Adversity’ where boundaries are defined based on parallels between the Acorn classification and SIMD.

5.7 Unbalanced Optimal Power Flow and Flexibility Modelling

Whilst conventional power flow analysis is necessary for understanding basic steady-state behaviour, an OPF is used to determine the optimal operating conditions of a network while adhering to various operational constraints and objectives e.g. minimising network losses in consideration of thermal and voltages limits. The open-source python-based package with a three-phase unbalanced OPF model developed in [295] is used as the base model for this work. The equations used to form the OPF model are derived from the current mismatch method presented in [296]. This model is advantageous compared with those used in studies which assume that loads on the three phases are balanced, as it allows for consideration of the practicalities of real distribution networks which typically have asymmetrical phase distribution. Note that this method does not explicitly account for modelling of the neutral conductor.

This section describes the key expressions used to define the three-phase OPF model in the open-source optimisation modelling language, Pyomo, according to [295]. It also describes the formulation of the smart charging and parametrised V2G model originally published in [138] which allows for multi-period optimisation of automated EV charging in response to time-of-use pricing signals and the approach taken for contingency load shedding. The application of these models relative to the case studies considered in this work is described in the proceeding section.

5.7.1 Base OPF Formulation

5.7.1.1 Definition of Nodal Current Injections

Derived from [296], the current mismatch equations are defined by (5.1)–(5.5). These are used to relate the nodal voltage phasors with the active and reactive power injections from each load and generating asset in the network.

$$\Delta I_k^s = I_{calc_k}^s - I_{sp_k}^s \tag{5.1}$$

$$P_{sp_k}^s = \Re(V_k^s)\Re(I_{sp_k}^s) + \Im(V_k^s)\Im(I_{sp_k}^s) \tag{5.2}$$

$$Q_{sp_k}^s = \Im(V_k^s)\Re(I_{sp_k}^s) - \Re(V_k^s)\Im(I_{sp_k}^s) \tag{5.3}$$

$$\Re(I_{calc_k}^s) = \sum_{i\in\Omega}\sum_{j\in\sigma_p}[G_{ki}^{sj}\Re(V_i^j) - B_{ki}^{sj}\Im(V_i^j)] \tag{5.4}$$

$$\Im(I_{calc_k}^s) = \sum_{i\in\Omega}\sum_{j\in\sigma_p}[G_{ki}^{sj}\Im(V_i^j) + B_{ki}^{sj}\Re(V_i^j)] \tag{5.5}$$

where

Ω set of network buses

$k, i \in \Omega$

σ_p set of phases $\{a,b,c\}$

$s, j \in \sigma_p$

$I^s_{calc_k}$ calculated ($calc$) current injections

$I^s_{sp_k}$ specified (sp) current injections

V^s_k, V^a_i phase voltage at bus k

G^{sa}_{ki}, B^{sa}_{ki} conductance and susceptance from nodal admittance matrix

In [295], load profiles are represented by a load composition in terms of constant impedance (Z), constant current (I) and constant power (P) i.e. a ZIP model. For this work, as only constant power information is available from the demand modelling previously carried out, equations (5.6) and (5.7), used to calculate the specified active and reactive power injections, $P^s_{sp_k}$ and $Q^s_{sp_k}$ respectively, are simplified to represent a constant power load model.

$$P^s_{sp_k} = P^s_{g_k} - P^s_{P_k} \tag{5.6}$$

$$Q^s_{sp_k} = Q^s_{g_k} - Q^s_{P_k} \tag{5.7}$$

where $P^s_{g_k}, Q^s_{g_k}$ are the active and reactive power generation[17] at bus k and phase s respectively, and $P^s_{P_k}, Q^s_{P_k}$ are the active and reactive power demand at bus k and phase s, respectively. For reactive power, this work assumes a constant power factor of 0.95 (inductive/lagging) for the domestic demand as in [297], and similarly, though conservatively, for the HP and EV demand as used in [94].

5.7.1.2 Equality Constraints

There are two equality constraints that are enforced within this OPF formulation, the current mismatch constraint defined by (5.8) and slack bus constraint defined by (5.9).

$$\Delta I^s_k = 0 \tag{5.8}$$

$$V^s_{slack} = V^s_{sp_{slack}} \tag{5.9}$$

[17] Generation in this context does not explicitly refer to generating technologies such as solar PV, rather the injection of power to the network at any given bus and phase.

The current mismatch constraint is used to force current deviations ΔI_k^s in (5.1) to zero and the slack bus constraint is used to force the slack bus voltage V_{slack}^s to equal the specified value $V_{sp_{slack}}^s$.

5.7.1.3 Inequality Constraints (Network Operational Limits)

There are three inequality constraints that form part of this OPF formulation, the voltage limits constraint (5.10), the line thermal limits constraint (5.11) and the transformer rating limits constraint (5.12).

In (5.10), the magnitude of the steady-state voltage V_k^s at bus k must conform to the respective upper and lower statutory limits, V_{max_k} and V_{min_k} according to the distribution network code.

$$V_{min_k} \leq V_k^s \leq V_{max_k} \tag{5.10}$$

In (5.11), the current flow I_l^s at each phase s on line l must not exceed the rated current capacity $I_{l_{max}}$ of the respective line as specified by the manufacturer.

$$I_l^s \leq I_{l_{max}} \tag{5.11}$$

In (5.12), the total apparent power flow S_n^{trans} across each transformer n must not exceed its maximum rating S_{max}^{trans} as specified by the manufacturer.

$$\sum_{n \in \Psi} S_n^{trans} \leq S_{max}^{trans} \tag{5.12}$$

where Ψ is a set containing all transformers.

5.7.2 Smart Charging and Parametrised Vehicle-to-Grid Model

As EV charging and subsequent energy consumption is time-coupled, $E_{e,t}$, which is the energy storage content of an EV during charge event e at time t, is dependent on the energy storage content of the EV at the previous time step and the change in energy, either gained or lost, during Δt as represented by (5.13).

$$E_{e,t} = (\eta_{ev} p_{e,t}^{\text{imp}} - \frac{1}{\eta_{ev}} p_{e,t}^{\text{exp}})\Delta t + E_{e,t-1} \tag{5.13}$$

where η_{ev} represents a fixed charging and discharging efficiency of 90% (this is in line with typical home charging efficiency values observed in the literature [298], [299]) and $p_{e,t}^{\text{imp}}$, $p_{e,t}^{\text{exp}}$ represent the power imported or exported by an EV during charge event e at time t.

The EV's battery energy content upon plug-out must be greater than or equal to what it would have received under an uncontrolled charging event (5.14). The EV driver may not necessarily need this amount of energy content to complete their travel plans, and they may be able to manage with a lower amount without any significant impact on their schedule. Therefore, a relaxation of this constraint could bring further benefits to the driver, such as increased revenue resulting from greater flexibility potential. The EV's energy content for each charge event e is constrained by the capacity limits, i.e. between 0 and the battery's maximum capacity E_e^{max}, $\forall\, t \in \mathcal{T}$ (5.15).

$$E_{e,\mathrm{t}_e^{\text{out}}} \geq \mathrm{E}_e^{\text{end}} \tag{5.14}$$

$$0 \leq E_{e,t} \leq \mathrm{E}_e^{\text{max}} \tag{5.15}$$

where $\mathcal{T}$ is the time horizon set comprised of half-hourly timesteps, indexed by t, $\mathrm{E}_e^{\text{end}}$ is the energy storage content of EV at end of charge event e and $\mathrm{t}_e^{\text{out}}$ is the plug-out time of EV for charge event e.

A typical constant current – constant voltage charging profile for lithium-ion batteries is used to constrain EV charging power [238], [300], where the maximum charging power equals the rated power P_e^{max} for a battery state of charge up to γ (set at 0.8 [301]), after which it linearly decreases to zero until a state of charge of 1 is achieved. The charging power constraint is stated formally in (5.16), $\forall\, t \in \mathcal{T}$.

$$p_{e,t}^{\text{imp}} \leq \begin{cases} \mathrm{P}_e^{\text{max}}, & \sigma_{e,t} \leq \gamma \\ \left(\dfrac{1-\sigma_{e,t}}{1-\gamma}\right)\mathrm{P}_e^{\text{max}}, & \sigma_{e,t} > \gamma \end{cases} \tag{5.16}$$

During an EV charge event e at time step t, the battery's state of charge, $\sigma_{e,t}$, is obtained from (5.17).

$$\sigma_{e,t} = \frac{E_{e,t}}{E_e^{\text{max}}} \tag{5.17}$$

For each EV, the active power discharged is constrained by (5.18).

$$p_{e,t}^{\text{exp}} \leq \mathrm{P}_e^{\text{max}} \tag{5.18}$$

With V2G capability, it is necessary to constrain the battery such that only either charging (power import) or discharging (power export) can occur at any single time step i.e. if an EV's import power at a given time step is greater than zero, then its export power is zero (and vice versa). This is achieved through the constraint (5.19).

$$p_{e,t}^{\mathrm{imp}} \times p_{e,t}^{\mathrm{exp}} \leq 0 \tag{5.19}$$

5.7.3 Load Shedding Method

To ensure network physical limits are satisfied within the OPF, load shedding is introduced. Load shedding is typically a last resort measure taken in extreme circumstances to maintain system operability e.g. use of under frequency load shedding schemes [156]. In this work, dynamic load shedding is modelled in terms of load curtailment, this ensures that the OPF will always satisfy the defined network constraints and that the OPF *should* always return a result, allowing for validation and testing. In practice, DNOs do not typically have the capability or communications infrastructure to dynamically curtail demand connected to existing LV networks. At LV, conventional overcurrent protection in the form of fuses would typically be used to disconnect overloaded parts of the network. Therefore, the idealised load curtailment modelled in the OPF is a proxy for such action.

To allow for independent control of the curtailment associated with each demand type, the value of lost load (VOLL) can be adjusted to force different curtailment behaviour relative to perceived curtailment priority. Whilst independent control of demand curtailment has significant scope for further research given the socio-technical implications, this work is less concerned about demand curtailment as it is simply a means to ensure operability. Should load curtailment be necessary, it is constrained by (5.20) and (5.21) such that demand can only be reduced and not increased.

$$p_{h,t}^{H} \leq P_{h,t}^{H} \tag{5.20}$$

$$p_{d,t}^{D} \leq P_{d,t}^{D} \tag{5.21}$$

where $p_{h,t}^{H}$, $p_{d,t}^{D}$ is the active power drawn by heat pump h and by household base demand d at time period $[t, t+1]$, $P_{h,t}^{H}$, $P_{d,t}^{D}$ is the unconstrained active power drawn by heat pump h and by household base demand d at time period $[t, t+1]$. Note that base demand refers to all other non-EV and HP demand.

5.8 Case Studies and Application of Modelling Methods

The following subsections outline the selected case study area and the developed case studies used to inform the analysis carried out in this work. Each of the case studies require a distinct application of the developed modelling capability e.g. case study 1 is the base case with no flexibility, therefore this only uses a statistical load flow method whereas flexibility for EVs is required in case study 2 and 3 which requires use of the formulated optimal power flow model previously described. Therefore, where appropriate these modelling distinctions are described relative to each case study in the respective subsections.

5.8.1 Case Study Area

To demonstrate the developed framework presented in this chapter, as described in the previous sections, a data zone was selected that covers the settlement of Insch, Aberdeenshire, in north-east Scotland. This area was chosen as it has several characteristics that would be likely to aid the uptake of EVs and HPs: a high gross disposable household income, a high number of cars at each household, a low proportion of gas-fired central heating systems, ubiquitous driveway parking, and a high proportion of residents reporting that they drive to work (Table 5.3).

Table 5.3. Key attributes of study area versus Scotland mean values (data from [302], [303])

Attribute	Insch	Scotland (mean)
Gross disposable household income (£/year)	20,220	16,160
Cars per household	1.78	1.1
Proportion residents who report driving to work	67.6	49.3
Proportion of households with gas-fired heating	5.59	74.2
Proportion of households with electric heating	18.1	13.4
Proportion of households with oil heating	62.25	5.70
Proportion of households with solid fuel heating	4.42	1.10
Proportion of households with other heating	1.70	0.70

Applying the heating technology uptake model (Figure 5.3) as described in Section 5.4.1, the resulting heating mix for each PLEF scenario (Table 5.1) for the case study area is shown in Figure 5.8. This figure shows that in 2030, for Ignore, Steer and Shift, the majority of households use oil fired heating and ESHs with only moderate uptake of HPs. However, in the Transform scenario, HPs are the dominant technology with significant uptake by comparison. In 2050, for Shift and Transform, HP uptake dominates and all legacy heating is fully displaced. For Steer,

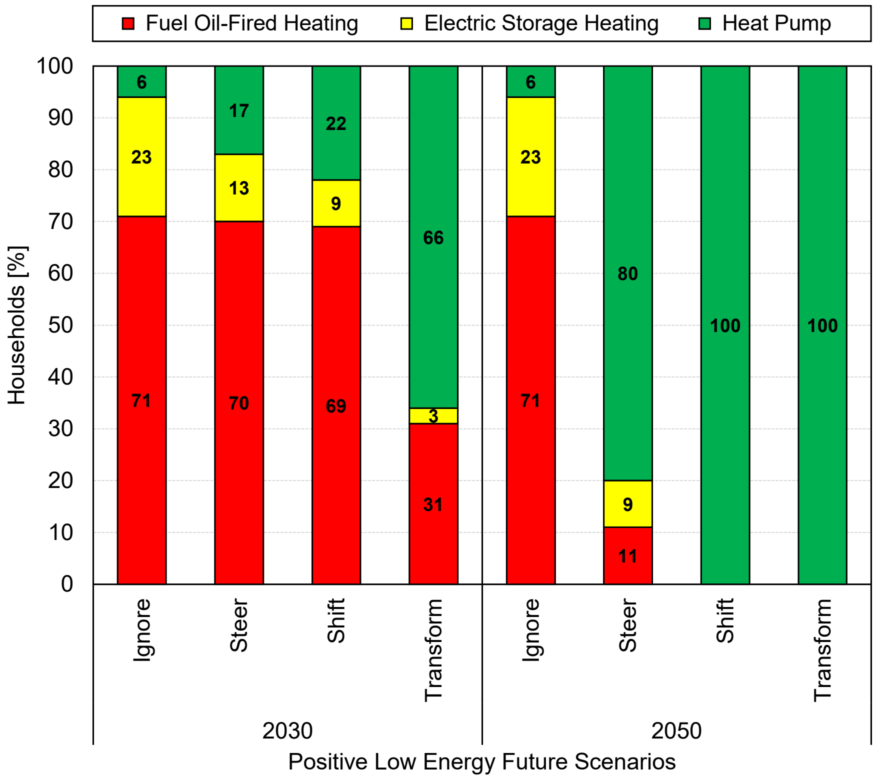

Figure 5.8. Breakdown of the heating mix for each year and positive low energy future scenario for the case study area.

there remains a small portion of households with oil fired heating and ESHs. In the Ignore scenario, there is no change in heating technology between 2030 and 2050. The technology uptake figures in Figure 5.8 provide the respective technology penetrations necessary to simulate the different future demand scenarios in the case studies outlined in the following sections.

The comparative reductions in annual heating demand for the PLEF scenarios in 2030 and 2050 for the case study area are shown in Figure 5.9. These are used to simulate improvements in building efficiency (e.g. improvements in building fabric) and improvements in heating system efficiency under the different future scenarios. The figure shows that under the Transform scenario greater reductions in heating demand are achieved than in Ignore, Steer and Shift. For the Ignore scenario, the observed reductions are lower in 2050 than in 2030, this aligns with the CREDS report [279] for energy demand reduction in the residential sector. In the CREDS narratives, changes in the long term can act against efficiency improvements.

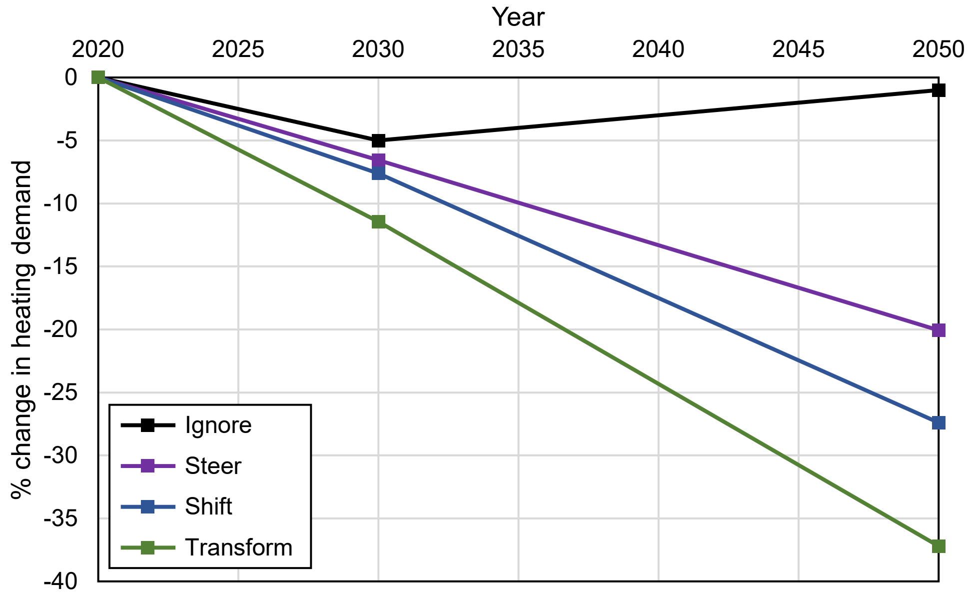

Figure 5.9. Heating demand reductions for each year and positive low energy future scenario for the case study area.

In terms of transport, the results of applying the PLEFs to the car stock model STEVE (as described in Section 5.4.2) for the case study are shown in Figure 5.10.

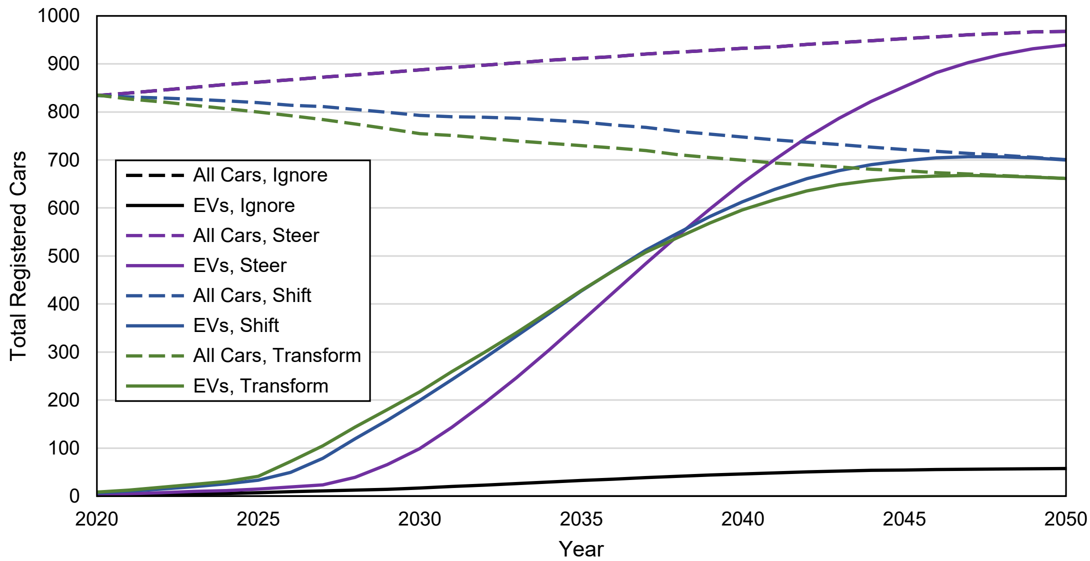

Figure 5.10. Total cars and proportion of EVs by scenario for study area as output by STEVE.

Figure 5.10 shows the total cars and proportion of EVs by scenario for the study area as output by STEVE. The figure highlights that a reduction in the total number of cars is observed for both the Shift and Transform scenarios up to 2050 whilst the total number of cars for Ignore and Steer increases in the same period (these overlap in Figure 5.10 as the Steer scenario uses the same energy service-demand projections as the Ignore scenario). For Shift and Transform, the proportion of these cars that are EVs increases significantly from 2025 and begins to plateau around 2045. For Steer, the proportion of cars that are EVs also increases significantly, though slightly less than both Shift and Transform in 2030, Steer has a greater proportion of cars that are EVs in 2050 by comparison. For the Ignore scenario, the proportion of cars that are EVs remains much lower in comparison with only a marginal increase across the same period. EV uptake for each of the scenarios for the case study area as shown in Figure 5.10 is then used to determine the proportion of EVs connected to the LV distribution network that is modelled within the study area. Figure 5.11 presents a detailed visualisation of this network which has been modelled using the method developed in Chapter 4 of this thesis.

Figure 5.11. Satellite visualisation of the LV distribution network under study using Bing Aerial showing which households are connected to which of the four network feeders in the area that are connected to the substation shown. Copyright statement: © 2023 Microsoft, Microsoft product screen shot(s) reprinted with permission from Microsoft Corporation.

5.8.2 Case Study 1: No Flexibility (Base Case)

This case study represents the base case where there is no optimisation or incentivisation driving flexibility modelling (i.e. the charging and discharging actions associated with the EVs). As a result, in this scenario, the EVs are essentially modelled as ‘dumb’ where the charge obtained for each charge interval is the battery’s maximum capacity relative to the charge constraints. With no flexibility, the focus of this case study is solely concerned with the network impact of the different future energy demand narratives. Algorithm 2, demonstrates at a high-level, the approach taken to carry out a statistical load flow impact assessment of the existing LV network infrastructure for this case study, where p_{ev}, p_{hp} and p_{esh} represent the penetration of EVs, HPs and ESHs, respectively.

Algorithm 2 Statistical Impact Assessment

for $year \in years$ **do**
    Transport spatial modelling: p_{ev} for *year*
    Transport temporal modelling: profiles for *year*
    Heat spatial modelling: p_{hp} & p_{esh} for *year*
    Heat temporal modelling: profiles for *year*
    while $i < min\ iterations$ **do**
        Sample ESH profiles based on p_{esh}
        Sample DD profiles based on remaining houses
        Sample EV charging profiles based on p_{ev}
        Sample HP profiles based on p_{hp}
        Stochastically distribute on the network
        Add to demand base load for each household
        Execute daily load flow
        Store results for every sampling iteration i
        $i = i + 1$
    end while
    return the distribution of results for *year*
end for

For each year modelled, spatially explicit uptake penetrations informed by the PLEFs are obtained for EVs, HPs and ESHs using the modelling approaches described in Section 5.4. The bank of smart meter profiles containing both ESH and generic domestic demand are first sampled and distributed relative to the ESH penetration. The secondary bank of smart meter profiles solely containing generic domestic demand (DD in Algorithm 2) are then sampled and assigned to each of the remaining households. Following this, a series of daily demand profiles with half-hourly temporal granularity are obtained for both HPs and EVs relative to their penetration. These are stochastically distributed across the network (with the constraint that households with an ESH should not also have a HP and that there should only be one ESH or HP for each household, there can be multiple EVs connected at each household with the ability to charge simultaneously) and combined with the base demand on a household basis. A statistical assessment with a number of sampling iterations is then carried out to ascertain the distribution of impact stemming from the uptake of these technologies.

5.8.3 Case Study 2 and 3: Smart Charging and Vehicle-to-Grid

The smart charging and V2G case studies are semi-related and are therefore described together in this section. Both the modelling method and the objective function used for the OPF are also described.

5.8.3.1 Modelling Method

For these case studies, EV travel diaries that represent travel behaviour (i.e. plug-in time and stay duration) are used as time-coupled constraint windows within the optimisation that inform when charge and discharge events take place. From the smart charging and parametrised V2G model described in Section 5.7.2, for case study 2 (smart charging), only the charging portion of the formulation is considered. For case study 3 (smart charging and V2G) the full formulation as presented is applied. This distinction is also applied to the objective function.

Linearisation of non-linear AC power flow equations to model voltages and reactive power has become common in recent years [304]–[306]. This chapter takes a traditional approach to non-linear ACOPF to account for the high line impedances and voltage variations typically observed in distribution networks [307]. However, with the time-coupled modelling of EV charging, this results in a significantly large-scale optimisation problem. Further complexity is introduced with the introduction of the V2G and discharging element in case study 3 as a complementarity constraint (5.19) is used to ensure that only either charging or discharging can occur at any single instance. Problems with these types of constraints are inherently difficult to solve. Therefore Knitro, a specialised solver for solving large scale non-linear mathematical optimisation problems (primarily using interior-point methods and active-set methods) with built-in techniques for handling such constraints, is used in this work [308]. Despite using Knitro to handle this complexity it is difficult to guarantee a global optimal solution, particularly when there are high penetrations of EVs. As such, case study 2 and 3 are only demonstrated at a feeder level to reduce the problem scale and complexity.

A high-level overview of the developed method for these case studies is presented in Figure 5.12.

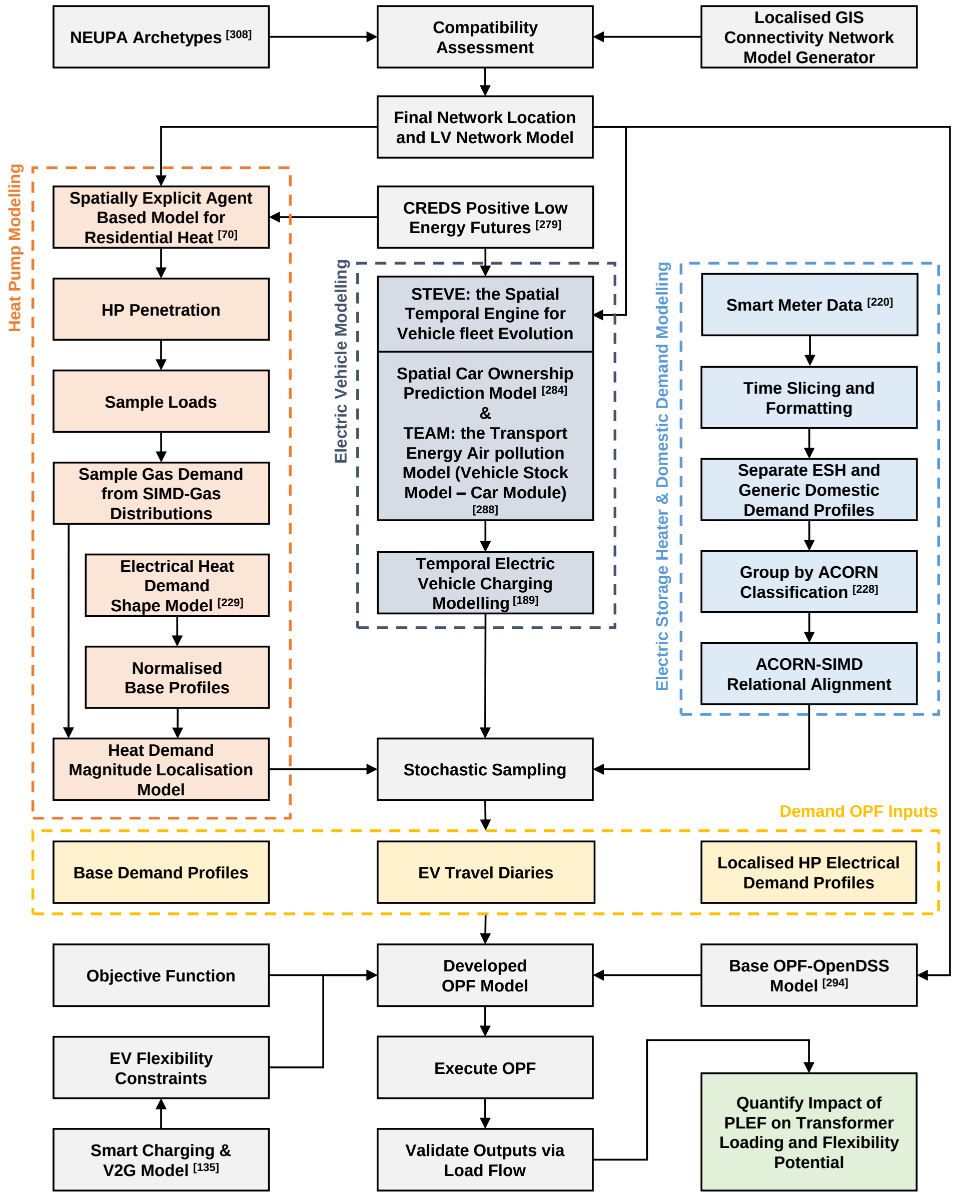

Figure 5.12. High-level flow chart of the entire methodology and integration of the various modelling techniques.

The figure highlights that contextual knowledge pertaining to the historical evolution of distribution network planning practices and standards in GB as summarised in the network headroom, engineering upgrades and public acceptance (NEUPA) project [309], [310], is paired with the distribution network modelling method described in Section 5.6.1. Whilst the NEUPA knowledge provides context and support for the place-based case study area that is the focus of this work, the LV network modelling method captures spatial and technical information pertaining to the local network infrastructure.

The figure then highlights the approach taken to model future spatial and temporal demand for heating and transport as described in Section 5.4 and Section 5.5, and domestic demand as previously described in Section 4.3.4. A similar stochastic sampling approach to the method described in Section 5.8.2 is then undertaken based on technology penetration for each future energy scenario and year simulated. The sampled outputs along with the network model then become the primary inputs to the unbalanced OPF model described in Section 5.7.

5.8.3.2 Objective Function

In this work, an optimisation is used to show an idealised utilisation of the available network capacity and demand flexibility to show the upper limit of what might be achieved by the latter. In acknowledgement of this, two distinct objective functions have been created, with one specifically for case study 2 and the other for case study 3. For case study 2 the objective function is to minimise the total cost of charging all EVs and the cost associated with any necessary load shedding whilst satisfying network constraints and asset physical limits. For case study 3, the total cost of discharging all EVs is also introduced and is given by (5.22), where E is a set of electric vehicles, indexed by e, H is a set of heat pumps, indexed by h, D is a set of base demands, indexed by d, $p^{ch}_{e,t}$, $p^{dch}_{e,t}$ are the active power charged and discharged by EV e at time period $[t, t+1]$, $c^{buy}_{e,t}$, $c^{sell}_{e,t}$ are the buy and sell price for EV e at time period $[t, t+1]$ and $Voll^H_h$, $Voll^D_d$ are the VOLLs for heat pump h and base demand d.

$$\min \sum_{t\in\mathcal{T}} \Bigg(\underbrace{\sum_{e\in E}(p^{ch}_{e,t} \times c^{buy}_{e,t}) - \sum_{e\in E}(p^{dch}_{e,t} \times c^{sell}_{e,t})}_{\text{Cost of charging and discharging all EVs}} + \underbrace{\sum_{h\in H}(P^H_{h,t} - p^H_{h,t})Voll^H_h + \sum_{d\in D}(P^D_{d,t} - p^D_{d,t})Voll^D_d}_{\text{Cost of shedding HP and base demand}} \Bigg)\Delta t \tag{5.22}$$

In case study 2, for $c^{buy}_{e,t}$, a flat price profile is used across the time-horizon (effectively minimising losses) whereas in case study 3, for $c^{buy}_{e,t}$, $c^{sell}_{e,t}$, the use case import (buy) and export (sell) Octopus Agile time-varying electricity tariffs (half-hourly price changes based on day-ahead wholesale rates) shown in Figure 5.13 are used as a price differential to demonstrate V2G functionality [311]–[313]. For load shedding, it is assumed that V_h^H, V_d^D are fixed at a penalty price of £16,940/MWh [314] such that the optimiser would only consider curtailment as a last resort measure.

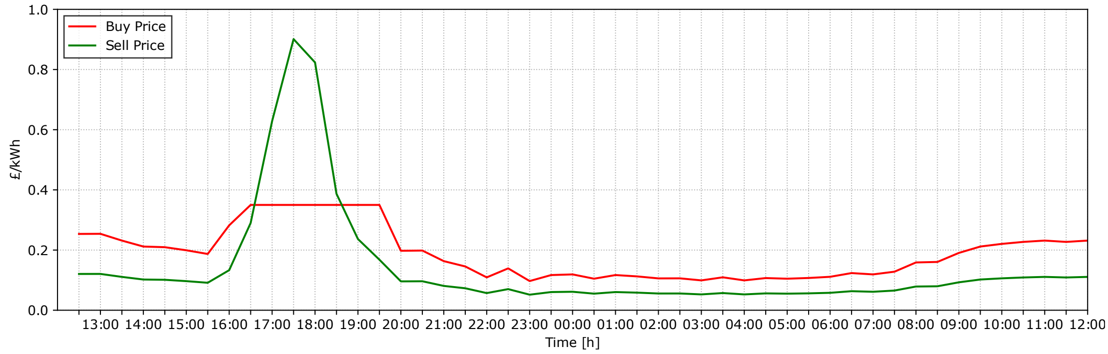

Figure 5.13. Use case Agile tariff price profiles with price differential for demonstration of V2G functionality.

5.9 Case Study Results

The PLEFs are modelled using the full assessment methodology developed in this chapter for 2030 and 2050 (these are key milestones in the net-zero time frame) for each of the case studies. For case study 1, results are presented by considering both transport and heat demand separately, and then combined. For case studies 2 and 3 only the combined impacts are considered.

5.9.1 Case Study 1: No Flexibility (Base Case)

The results for case study 1 are presented in Figure 5.14 and Figure 5.15 where the impact of the PLEF scenarios on transformer loading across two days (a 0°C winter Tuesday and Wednesday) is shown for 2030 and 2050, respectively. These results are reported in terms of the average transformer loading for the sample and also show the interquartile range variance. In each figure, electricity demand from other domestic devices is included. The top plot shows additional demand from transport only (i.e. no change in heat demand or supply technologies are modelled); the middle plot shows additional demand from heat only (i.e. no change in transport demand or supply technologies are modelled); the bottom plot shows the combined impacts from heat and transport (i.e. changes in both are modelled). Note that to show impact over the two day period, it is assumed that domestic demand and heat demand are similar each day i.e. a standard two day working period in winter where the average temperature is 0°C.

Considering transport demand, it is demonstrated that the uptake of EVs in all scenarios has a significant impact on the traditional evening peak. From Figure 5.14, the impact of EV uptake is much less pronounced than in Figure 5.15, emphasising that penetration is the key determinant of impact in terms of magnitude. This is further evidenced when comparing between the different PLEF scenarios in each of the figures. In Figure 5.14, the Shift and Transform scenarios are similar with only marginal difference from Steer. However, in Figure 5.15, the difference between the Steer scenario and both the Transform and Shift scenarios is more prominent around the traditional evening peaks. The observed difference between Shift and Transform is primarily due to the changes in number of trips and trip distance between 2030 and 2050 as presented in Table 5.2. An additional observation is the difference in scenario impact around the traditional evening peak on each individual day in Figure 5.15, with the difference between the scenarios typically more pronounced on the Wednesday showing the Transform scenario to have a lower impact than in the Shift scenario and a reduction in the peak for Steer. This relates to the prevalence of certain trip types in certain weekdays, and is reflective of wider variation in travel habits as per the UK NTS [213].

Considering heating demand, in both Figure 5.14 and Figure 5.15, there is an observed increase in demand during the early morning hours that can be attributed to the ESHs. This noticeably decreases in the Shift and Transform scenarios in comparison with the Ignore and Steer scenario as the ESHs are replaced with HPs. Also, for Shift and Transform, a second morning increase in demand that can be attributed to HP usage for space heating demand is observed. In Figure 5.14, as similar with EVs, penetration dominates impact in terms of magnitude and there is a distinct difference between Transform and the other scenarios (Transform has a higher percentage penetration of HPs in 2030 as in Figure 5.8). In Figure 5.15, where both Shift and Transform HP penetrations are 100%, the marginal difference in impact can be attributed to the representative heat demand reductions used in each scenario. Additionally, despite Transform having a greater number of HPs than Steer, due to the comparative difference in heat demand reductions this results in a fairly similar profile in terms of magnitude.

Considering the combined effects of heating and transport, the extent of the impact is evident in comparison of Figure 5.14 and Figure 5.15. In Figure 5.15, the traditional evening peak

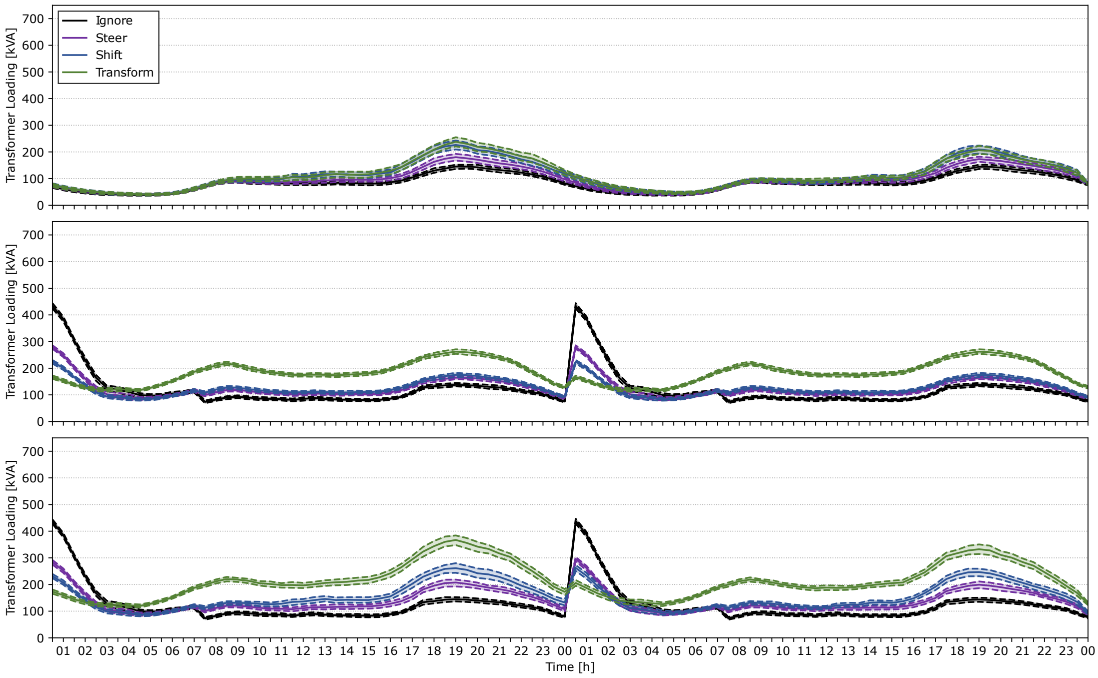

Figure 5.14. Impact on transformer loading for 2030. (top) Transport demand. (middle) Heat demand. (bottom) Combined demand.

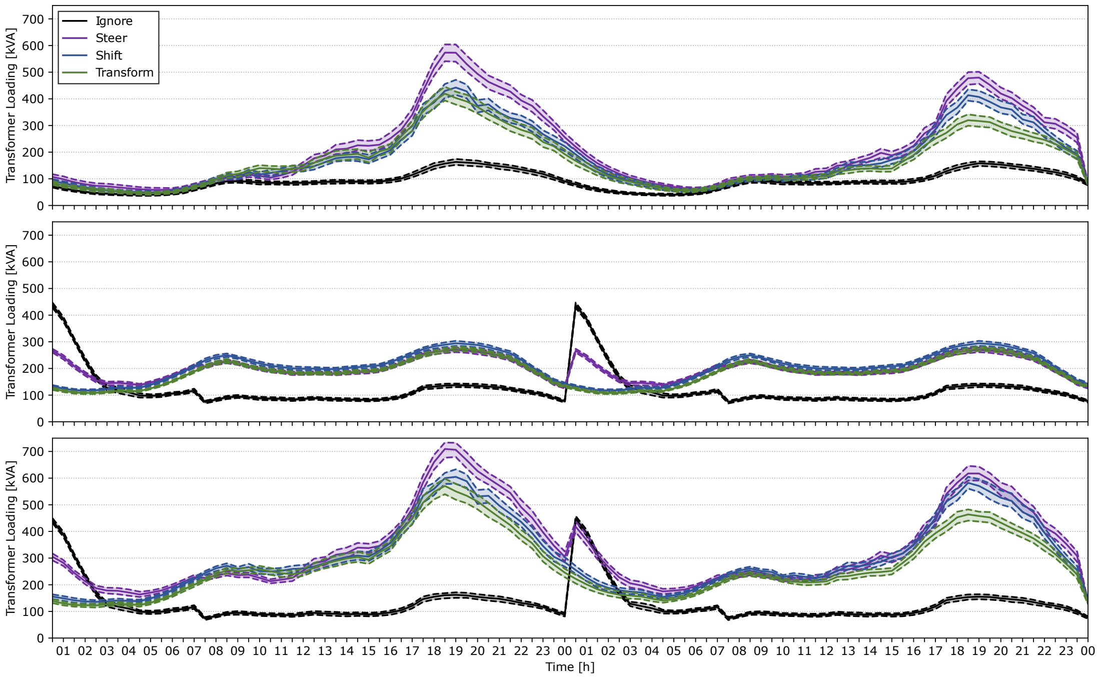

Figure 5.15. Impact on transformer loading for 2050. (top) Transport demand. (middle) Heat demand. (bottom) Combined demand.

is significantly increased for the Steer, Shift and Transform scenarios in comparison with the Ignore scenario, increasing from an approximate loading of 200 kVA in the Ignore scenario to 500-750 kVA in the Steer, Shift and Transform scenarios. Note that the rating of this transformer is 800 kVA and would likely have initially been sized to accommodate the large increase in demand at midnight stemming from the ESHs. However, consider that the case study represents a location that, today, predominantly uses gas heating but otherwise is the same as the case study area. The ESH related loading would only be present for any household that adopts them in place of gas heating. With the policies present in the Shift and Transform scenarios the agent-based model indicates that all households would adopt HPs. For Steer, it is likely that the majority would also adopt HPs with a smaller portion continuing to use gas. In Ignore, they would continue using gas. Therefore, in a network that was not designed to accommodate ESHs, the substation would likely have a lower kVA rating unless oversized for a particular reason in the planning process. As such, given transformer headroom is significantly eroded in the combined scenarios, it raises concerns with existing transformers that have lower levels of headroom currently available. Also, as HPs are constrained to one at each household and EVs can have multiple connections that charge simultaneously, EV impact tends to dominate.

Ultimately, a network operator's decision to invest in network reinforcement is based on its peak loading. As such, transformer headroom is considered next. The headroom for a particular time interval (h_t) is a measure of how much spare capacity is available in a transformer at a specific instance in time, expressed as a percentage of maximum capacity. It is calculated by comparing the apparent power observed at that specific time interval (S_t) to the transformer's rated capacity. For this analysis, the classification approach as previously described in Chapter 3 is used to split the daily headroom into four percentage bands: $h_t \geq 75$, $75 > h_t \geq 50$, $50 > h_t \geq 25$ and $25 > h_t$. Using this classification, Figure 5.16-5.18 present a comparison of each PLEF scenario by year, considering in turn demand from transport, heating and combined impacts, showing the transformer headroom as a percentage of the time spent in each classification band across all simulations in the sample. These figures are used to complement Figure 5.14 and Figure 5.15 and the accompanying analysis.

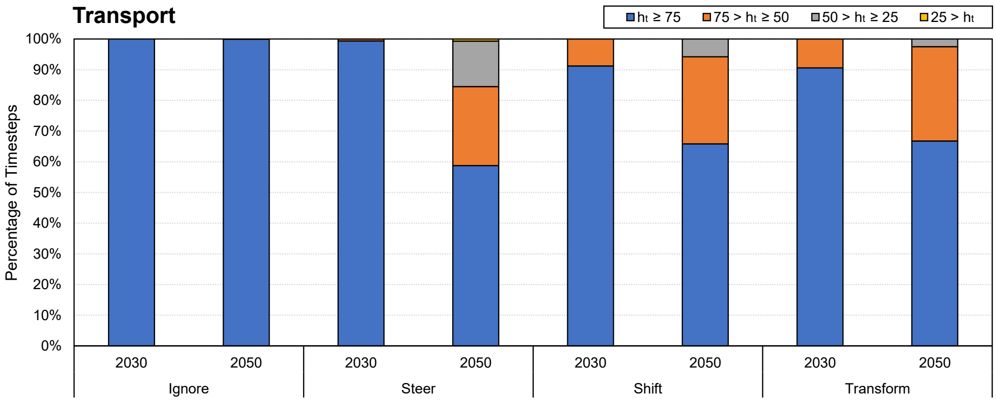

Figure 5.16. PLEF scenario comparison by year considering only transport demand, showing the transformer headroom as a percentage of the time spent in each classification band across the sample.

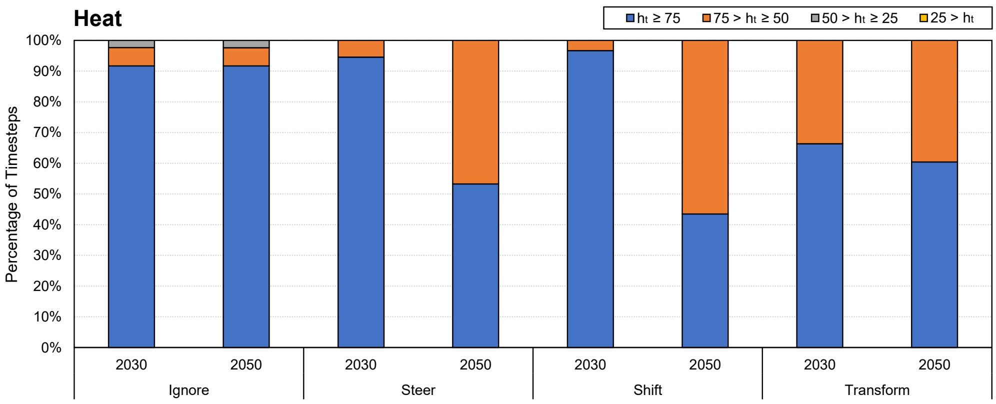

Figure 5.17. PLEF scenario comparison by year considering only heating demand, showing the transformer headroom as a percentage of the time spent in each classification band across the sample.

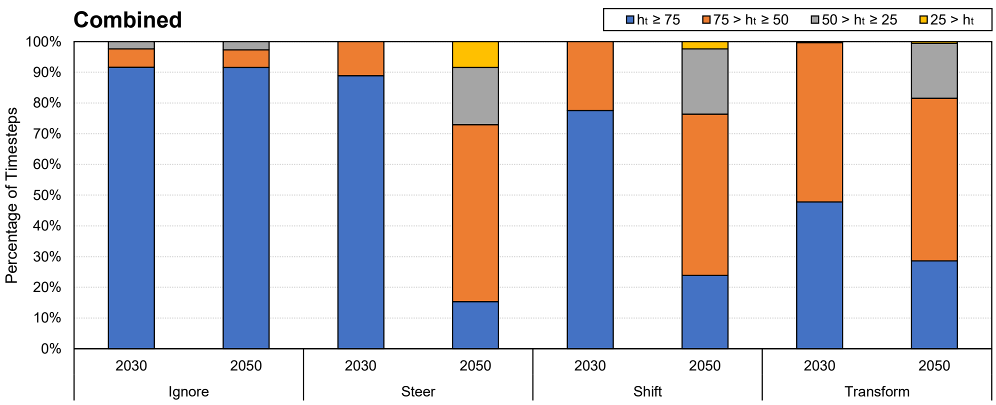

Figure 5.18. PLEF scenario comparison by year considering both transport and heating demand, showing the transformer headroom as a percentage of the time spent in each classification band across the sample.

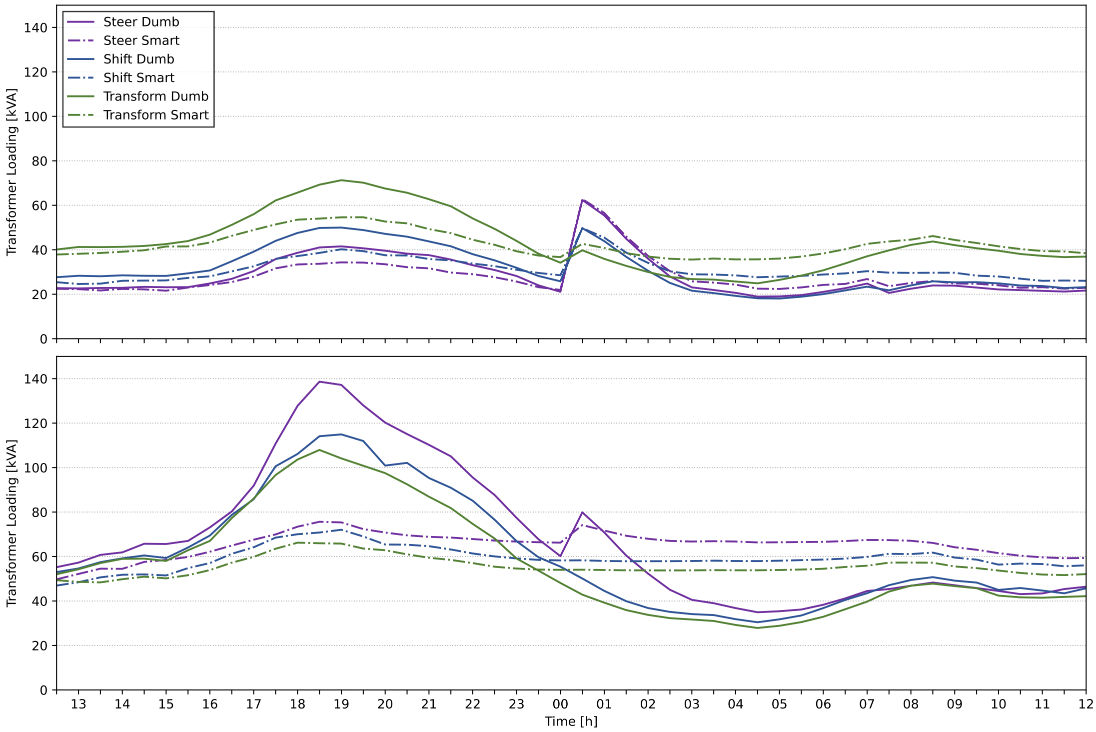

Figure 5.19. Impact on transformer loading with only feeder 1 modelled for Steer, Shift and Transform scenarios in 2030 (top) and 2050 (bottom) comparing smart charging with dumb charging – both heating and transport demand.

5.9.2 Case Study 2 and 3: Smart Charging and Vehicle-to-Grid

For case study 2, Figure 5.19 shows the impact on transformer loading (with only feeder 1 modelled) for the Steer, Shift and Transform scenarios in 2030 and 2050 comparing generic 'dumb' EV charging with smart EV charging for combined heating and transport demand. In this figure, whilst the optimisation is performed over the same two day period, the results are presented over a period that spans from 12:30 to 12:00 the following day to emphasise the impact of smart charging on the evening peak and overnight (typically when it would be expected that the bulk of charging would be carried out). The figure demonstrates that flexible smart charging can be used to reduce peak demand in each of the PLEF scenarios, both in 2030 and 2050.

For case study 3, Figure 5.20 shows the impact on transformer loading (with only feeder 1 modelled) for the Steer, Shift and Transform scenarios in 2030 and 2050 comparing dumb charging with use of smart charging that includes V2G. As before, electricity demand from

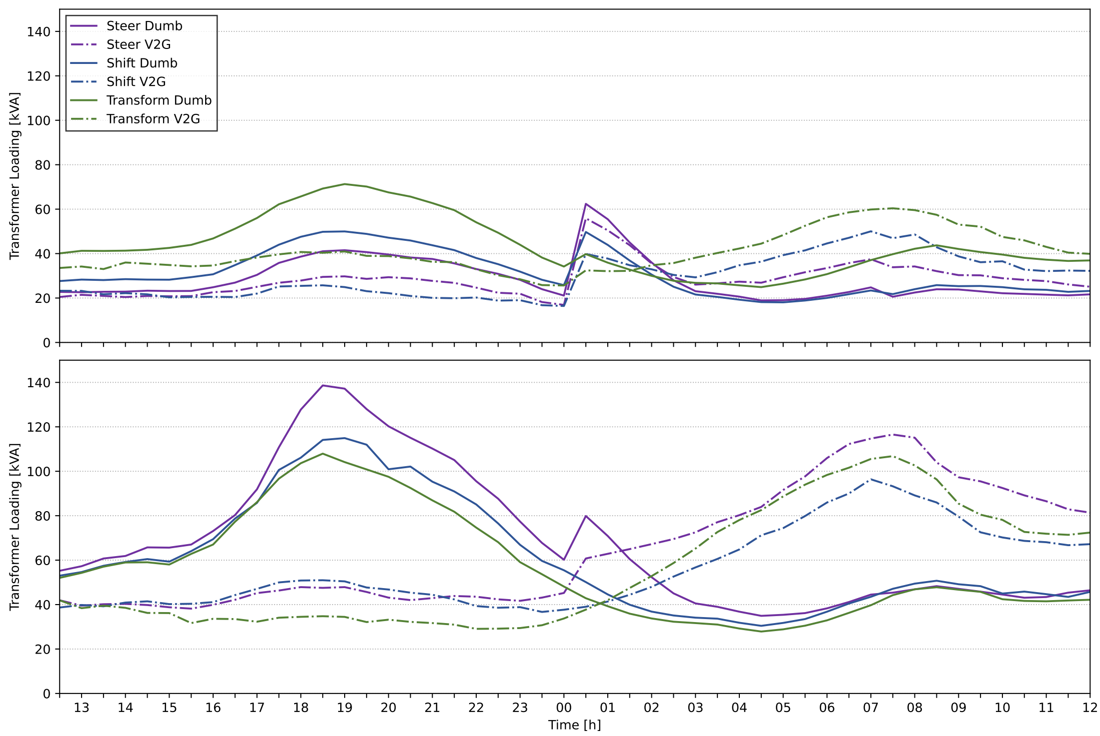

Figure 5.20. Impact on transformer loading with only feeder 1 modelled for Steer, Shift and Transform scenarios in 2030 (top) and 2050 (bottom) comparing V2G with dumb charging – both heating and transport demand.

both transport and heating is considered. In the V2G scenarios, with the use case Agile price profiles, the evening peak loading as seen at the transformer is further reduced in all scenarios. The extent of this reduction is accentuated in 2050, primarily as there are a greater number of EVs connected. Whilst the traditional evening peak is significantly reduced, there is a substantial increase in overnight charging in each of the scenarios. This emphasises that although the V2G scenarios have an impact that exceeds that of the smart charging with respect to the traditional evening peak demand reduction, the overnight demand increase from charging is greater in comparison. This would be expected as the EVs operating as V2G during the traditional evening peak would have a reduced capacity and thus require additional demand than in the smart only scenario to satisfy the charging constraints.

Ultimately, Figure 5.20 shows the increase in the potential for EV charging demand to act more flexibly under the more ambitious PLEF scenarios. This results from the assets having a lower duty cycle, being available more with a lower requirement for energy. Whilst underused private vehicles are a persistent symptom of modern transportation systems, their use as distributed electricity storage providers has the potential to offer benefits to the wider energy system.

On the basis of the presented case studies, which considered a typical winter demand day, energy futures based on energy demand reduction policies were found to reduce evening transformer loading significantly. The transformer loading between 16:00 and 21:00 in 2050 was found to reduce on average by 11.55% and 16.10% for the Shift and Transform scenarios relative to the Steer scenario. In addition to energy demand reduction based policies, introduction of flexible smart charging achieved reductions on average of 39.26% and 43.29% for the Shift and Transform scenarios relative to the Steer scenario. The achievable reductions increased to 56.64% and 69.07% for the Shift and Transform scenarios relative to the Steer scenario with the use of V2G (driven by the use case import and export Octopus Agile tariffs).

5.10 Discussion

The discussion presented in this section takes a wider contextual view of the presented findings and considers the broader implications. The value of the developed methodology is also established with respect to key actors that are actively involved in the energy transition.

5.10.1 Electricity System Operators

The method presented in this work describes an approach that has the ability to postulate what electric heating and EV charging demand would be for a particular local area under particular future scenarios. The approach then has the capability to assess whether a particular electricity distribution network could accommodate those demands and the extent to which optimal utilisation of smart charging can avoid or defer network reinforcement. The findings emphasise that local level challenges will emerge as to when and where investment in infrastructure and management solutions should be focused, emphasising the challenge with both heat and transport electrification and the extent that this may impact existing infrastructure. This extends beyond use of simplistic network planning metrics such as ADMD – the highest point of electricity consumption that is expected to occur after accounting for consumer diversity – which looks at individual instances of peak demand separately and therefore does not account for coincidence of maximum demand peaks, potentially leading to an underestimation of the actual network requirements during critical periods.

Areas with higher flexibility potential can be identified using the presented method. However, to fully capitalise on this, several questions remain: how would the necessary flexibility actions for a particular day be identified, and who would be responsible for carrying them out? Does the DSO have a role? Will this depend on householders responding to price signals as modelled in this work (with some uncertainty as to whether they will)? Or is there a role for a third party to do the work for energy users (using automation, i.e. adopting technology as an enabler of behavioural change)? A challenge in the case of using price signals, is that price signals articulated only at a wholesale/national system level may fail to reflect the times at which local network constraints arise.

The case study area described in this work has been used to demonstrate the presented method's high-resolution applicability at the 'local' level. However, it also must be recognised that this is a single local area with one ground mounted secondary transformer. Therefore, it is also important to acknowledge the wider implications in the context of aggregated impacts at the national and sub-national level, i.e. as seen by the transmission and wider distribution networks. The methods presented for estimating future energy demand and the likely time series of power demand are generally scalable for use at less granular resolutions. The main challenge is around mapping this to detailed network models. The network modelling methodology used is highly transferable in that different LV networks for alternative case study areas can be easily modelled. Simplifications such as use of a single phase model and relaxation of constraints e.g. voltage or thermal can be made to improve scalability.

5.10.2 Policy Makers and Local Authorities

Local authorities have the potential to influence and guide locally-specific decarbonisation pathways [239]. This requires high-level planning and a significant understanding of local requirements. It is also recognised that the feasibility of interventions from such parties are highly dependent on future network capability and headroom e.g. works including [241], are recommending that local government should have a statutory role in guiding the future development of local energy infrastructure, including investment decision-making. To do so effectively, whilst also addressing social objectives, they require an understanding of network capability and future flexibility potential based on the unique characteristics of specific localities. They also require a broader understanding of different types of emerging heating technologies including heat networks (and for those heat networks to access low carbon sources of heat, which might be large electric HPs) and for use of low carbon hydrogen. This would allow for investment to be optimised with better foresight of regional economic plans and local area energy infrastructure. The method presented in this chapter can be used to inform on the impacts of local development strategies and the proposed interventions in this regard.

For policy makers the presented method can be used to inform on the impacts of decision making in this space e.g. as evidenced through the presented findings and analysis, the policy options and narratives (described in detail in [279]) that underpin the modelled future scenarios yield different network impacts at varying timescales. The extent of the value from such policies in terms of impact can therefore be quantified. This allows for questions to be raised on whether or not the existing future scenarios actually go far enough. From the presented findings, in terms of electrification, it is demonstrated that policy focused on the uptake of LCTs in the heat and transport sectors is likely to have a greater impact on networks in comparison with policy focused primarily on behavioural aspects. However, clearly the uptake of new technologies and their corresponding demand schedules are intrinsically linked. In this chapter, the potential contribution to mitigating the need for electricity network reinforcement from pursuing energy demand reduction policies has been presented.

Furthermore, policies aimed at enabling the use of smart functionality to unlock the flexibilities offered by electrified technologies are likely to have significant impacts on networks. The findings evidence that greater peak demand reductions can be achieved when these are applied in combination with policies focused on consumer behavioural aspects of demand reduction.

5.11 Chapter Summary

This work presents a methodology to translate narratives on energy demand futures in heating and transport to impacts on local electricity systems, enabling quantification of the stress placed on key infrastructure and the ability of those demands to act ‘flexibly’ in supporting the renewables-dominated generation mix necessary to achieve energy system decarbonisation at pace. Previously developed low energy future demand scenarios are used to drive spatially explicit modelling of the uptake of electrified transport and heating; and temporally explicit modelling of the electricity demand of these technologies for a local geography.

The methodology is demonstrated on a model of a real electricity distribution network that serves households within the local geography and is used as the basis to examine the impacts of the varying demand scenarios on network infrastructure. An OPF formulation that enables smart EV charging and V2G also forms part of the methodology and is used to investigate the impact of these future demand scenarios on the potential of flexibility in electricity demand.

Electrification of heat and transport enables more efficient use of primary energy than use of fossil fuels. However, as a consequence, the electricity demand will significantly increase, challenging existing electricity system infrastructure. On the basis of the reported findings, it is concluded that energy demand futures with policies focused on energy demand reduction using the *Avoid-Shift-Improve* framework [269] are shown to mitigate the need for reinforcement of electricity networks (for the case study considered a reduction in evening transformer loading of up to 16% can be achieved). However, flexibility in electricity demand contributes a larger difference to a network's ability to host electrified heat and transport than relying solely on energy demand reduction. Energy futures that combine policies that pursue energy demand reduction and simultaneously enable electricity system flexibility present the greatest benefits, both to the mitigation of reinforcement and to system operability in the context of growing penetrations of variable renewable generation (for the case studies considered a reduction in evening transformer loading of up to 69% can be achieved). Despite these benefits, it has been shown that electricity demand is still likely to increase significantly relative to the current baseline. Therefore, widespread network reinforcement of the electricity system will still be necessary in the transition to net-zero and, accordingly, urgent investment is required to support the realisation of the UK's legally-binding climate goals.

Chapter 6

Conclusion

In response to the escalating threat of climate change, governments worldwide have committed to taking varying levels of action to reduce carbon dioxide emissions. Several legally binding international agreements have been forged, underscoring a collective resolve to address the unfolding crisis. In many nations, including the UK, a rapid increase in electrification has been recognised as being critical to most decarbonisation pathways and central to the decarbonisation of both the residential heating and transport sectors. This would involve replacing existing technologies reliant on fossil fuels with low carbon alternatives powered by electricity produced from renewable sources of generation. Through electrification, distribution networks are becoming increasingly more active and their requirements and that of their operators must evolve if they are to accommodate the changing energy landscape. This requires a need for innovation and novel approaches that have been designed specifically to tackle the emerging challenges with the ongoing transition to a low carbon society. This requirement extends beyond the DNOs to other stakeholders who have an active role in the transition and will be required to make decisions which may influence how consumers interact with the electricity system.

6.1 Thesis Findings

Revisiting the primary objectives of this thesis:

1. To bridge the gap in understanding on how distribution network assets are affected by LCT uptake in consideration of social and spatial diversity, and to assess the value of this understanding by exploring the ramifications for various stakeholders.

2. To investigate the state-of-the-art with respect to LV network modelling techniques and determine their sufficiency for localised modelling at scale, and to address the limitations of existing modelling techniques for spatially explicit place-based LCT impact analysis.

3. To translate narratives on energy demand futures in heating and transport to impacts on local electricity systems, enabling quantification of the stress placed on key infrastructure and the ability of those demands to act 'flexibly' in supporting the renewables-dominated generation mix necessary to achieve energy system decarbonisation at pace.

In consideration of these objectives and their respective research questions, the primary findings of this thesis are subsequently presented below. Following this, a broader view of the findings in the context of the overarching research question is presented.

How can geospatial and socio-technical analysis support assessment of LCT impact on distribution network infrastructure to inform network and policy decision making?

In recognition that, whilst research on the impacts of individual LCTs (i.e. either EVs or HPs) on distribution networks is plentiful, the literature on the combined effects of EVs and HPs on network infrastructure is comparatively scarce with only a handful of published studies. Of the existing studies that consider both EVs and HPs, none use socio-economic indicators in forming their analyses at granular resolutions, which has been established as a major driver of household energy consumption [95]–[98] and subsequently, a key determinant in influencing the necessary network investment.

Therefore, a novel methodology that enables assessment of electrified heat and transport impact on transformer headroom at scale using socio-economic indicators to inform the application of LCT consumption data was developed. This methodology is applied to a fleet of over 4,000 ground-mounted secondary transformers distributed across the north of Scotland and a subset are used to inform the analysis.

In terms of the DNO, the impact of place-based socio-technical analysis is demonstrated, emphasising that whilst non-localised modelling approaches may still be considered an improvement to conventional simplistic load modelling techniques for headroom quantification, such approaches can risk misallocation of planning resources and failure to reinforce in time in certain areas. The where, and to a certain extent the when, are what is missing from DNO plans and this is where new and different thinking is required to move them beyond existing reinforcement and asset replacement approaches. As the network evolves, local level challenges may emerge as to when and where investment in infrastructure and management solutions should be focused, emphasising the challenge with both heat and transport electrification and the extent that this may impact existing infrastructure.

The vast majority of system wide demand related studies are conducted at a primary level, given the volume of secondary transformers and the data related challenges. However, with the uptake of locally sensitive LCTs, this work takes a more granular approach that is targeted at the secondary level. Although results are reported in terms of generalised indicators of the true headroom (downstream voltage limit breaches and cable overloads are not considered), they are used predominantly to reveal the impact of localisation and the need to consider socio-technical and socio-spatial dimensions in detailed technical studies. The final operational decision between adopting a flexible solution or network reinforcement to manage the electrification of heat and transport as part of a development plan would still require technical assessment and a business case, but the developed method of this thesis, can help identify where such detailed targeted assessment studies should be performed.

In terms of local authorities and policy makers, the influence local sensitivities may have in relation to electrical infrastructure impact and subsequent investment requirements is demonstrated. As such, the analysis presented has the ability to support a 'just transition' which is a key component of many national government strategies [76], by enabling better understanding of the wider impacts of place-based electrification in specific areas i.e. by having a better understanding of HP uptake impact in a specific region thus enabling co-developed plans with the DNO to be determined. This then allows for planning and funding allocation in relation to budgets and operational allowances to be optimised with respect to 2030 targets in the net zero transition. This is particularly valuable when considering social welfare and fuel poverty in consideration that English regions with the highest fuel poverty and coldest winter climates are currently not receiving the most heat funding [241], [242]. This reiterates that the social imbalance of wealth may inadvertently have an influence on investment as early adopters and 'able-to-pay NOW' consumers are typically located in areas with lower social deprivation. The developed method therefore, has the potential to feed into wider multi-disciplinary collaborative works that are seeking to tackle this problem.

In summary, in response to this research question, this thesis has evidenced that geospatial and socio-technical analysis has significant potential to support the assessment of LCT impact on distribution network infrastructure, emphasising through novel-methodology development the value of this analysis for informing network and policy decision making. The findings provide insights into the value of localised modelling and in particular, they indicate that the broad link between social diversity and heat demand variation has the potential to influence decision-making. This is of particular concern in the near-term where affordability and access to LCTs is expected to be a barrier for those in areas with higher social deprivation. The work also highlights an increasing need to consider the combined uptake of different LCTs with respect to the electrification of heat and transport and the cumulative severity of this combined impact. Confirming that different demand-side management services will be required to avoid significant evening peak demands in addition to reinforcement. For example, scheduling of EV charging, adoption of time-of-use tariffs and changes in consumer energy awareness and behaviour.

What role does scalable place-based LCT and detailed LV network modelling have in supporting informed LCT impact assessments and local-level decision making for different stakeholders?

With a growing appetite to move beyond the modelling of 'generic' LV networks where less emphasis is placed on specific networks and their locale, works such as [94], [104] have identified that the use of network GIS data has significant LV network modelling potential, generating a number of models that have been extensively used. Although these models typically represent the largest available collection of GIS-network models for a particular area to-date, the anonymity of these networks ensures that there is no information available on the local characteristics e.g. building types and consumer demographic. This makes it particularly challenging to carry out place-based characterisation of the local demand through socio-spatial and socio-technical analysis, and tailored forecasting of LCT uptake. Whilst the occasional development of other individual isolated GIS-network models as in [105] is not uncommon within the literature, these networks tend to be created specifically for bespoke case study demonstration and are not derived with a centralised automated method that allows for scalable use across different areas. This is in addition to the established scarcity of research surrounding the combined effects of EV and HP impact on network infrastructure.

Therefore, a scalable approach to localised LV network and LCT impact modelling that can be used to support place-based infrastructure investment decision making was developed by coupling two modelling methods: a LV network model development methodology and a LCT impact assessment methodology which accounts for both the electrification of heat and transport demand. This methodology is applied to a distribution network licence area spanning the north of Scotland and the presented results demonstrate the developed modelling capability through a series of scenarios on two case study networks. The impact assessment study is used as a means of demonstrating the suitability of the scalable LV network development methodology and the value of place-based LV networks, but also to probe gaps in the literature that relate to electrified heat and transport impact assessments and the approaches taken to model diversity in heat demand at granular resolutions. Multiple assessment metrics are used to demonstrate the modelling approach and to quantify the impact on network infrastructure.

It is emphasised that the uptake of both EVs and HPs in parallel is expected to cause significant challenges for network operators, particularly as LCT penetrations increase. This is quantified as part of the studies considered. Similar trends exist across the different scenarios in that as LCT penetration levels increase as does the frequency of voltage and thermal violations with voltage violations being the more dominant. The time at which these violations occur is a critical issue that without regulation is subject to individual technology usage patterns. An increase in violations around the traditional evening peak is observed along with an increase in the early morning for the HP scenarios and an increase of the VUF is also observed in certain instances around similar times. The network headroom decreases as penetrations increase. However, this reduction varies non-uniformly across individual feeders. By adopting a localised approach to HP modelling the results presented provide the basis for understanding how variations in local heat demand may influence overall HP impacts further demonstrating the value of scalable localised modelling.

With this, it is considered that place-based assessments of network infrastructure for LCT uptake have a significant role in future network planning. Having such modelling capabilities will allow DNOs to capture the unique characteristics of networks and their subsequent demand requirements in different locations which, as evidenced in this thesis, can lead to a more representative articulation of the impact from heat and transport LCT uptake. When place-based forecasting of technology uptake is used in parallel with detailed LV network and LCT demand modelling, the role of place-based network infrastructure assessments in network planning becomes even more valuable to the DNO providing the means to tackle the existing challenges of 'when' and 'where'. In addition to the DNOs, place-based analysis of network infrastructure has significant potential to support local-level decision making for policy makers and local authorities. Place-based LCT and detailed LV network modelling in this regard has the ability to inform on the impacts of particular policies and strategies. In taking into consideration the impacts of local-level decision making on electricity network infrastructure, it allows for investment in decarbonisation solutions to be optimised for different areas with varying requirements.

The developed localised LV network modelling methodology can be used to support a wide range of LV network studies from spatial and temporal socio-technical modelling of demand to the development of locally sensitive demand side management techniques through enhanced flexibility quantification. This methodology is guided by high-resolution network information supporting the scalability necessary for network modelling in different geographic regions comprised of diverse local characteristics. This work has evidenced that the method has the capability to reduce the uncertainty surrounding EVs, HPs and demand diversity. This can facilitate the development of techniques that better capture and characterise the impact of local conditions on LCT demand profiles and the subsequent impact on the LV network beyond existing published work in this area. As the developed methodology utilises GIS data and geospatial datasets of varying spatial and temporal resolutions it has limitations that are not uncommon with data-driven modelling approaches, these include data availability, quality and quantity. However, this work has shown that in general these challenges can be managed to support enhanced modelling.

In summary, in response to this research question, this thesis has evidenced that the fusion of datasets containing local information with detailed scalable LV network modelling can support better decision making by enabling place-based analysis of LCT impact on electrical network infrastructure. Identifying that the impact from both EVs and HPs significantly compounds the network challenges and as such, affects planning and asset management approaches. The work also identified potential challenges with unconstrained flexible demand side management approaches, e.g. the potential for flexible peak shaving techniques to coincide with space heating demand. This indicates that a mix of LCTs should be considered in the development of such techniques, with a more holistic approach being adopted, and that existing capacity constraints in addition to local conditions will influence the suitability of flexible network management applications, emphasising that different areas of network may require particular consideration.

What impact does different future energy demand narratives have on local electricity systems and demand flexibility?

Whilst there is demonstrably a considerable body of literature on the impacts of electrification on electricity system infrastructure (predominantly from individual LCTs with only some combinational works) [82]–[94] and potential of demand flexibility [106]–[109], none of these studies consider the future evolution of energy service demand as a result of shifting societies, evolving technologies and policies that actively support energy demand reduction in the name of climate change mitigation and promotion of human well-being at the local-level. This is identified as a considerable research gap; to the author's knowledge, there has been no work on linking pathways in energy demand futures – such as those presented in [110] – to the potential impacts on infrastructure and the value proposition of local energy system flexibility in consideration of both the electrification of heat and transport demand.

Therefore, a methodology to translate narratives on energy demand futures in heating and transport to impacts on local electricity systems, enabling quantification of the stress placed on key infrastructure and the ability of those demands to act 'flexibly' in supporting the renewables-dominated generation mix necessary to achieve energy system decarbonisation at pace was developed. With this, existing low energy future demand scenarios are used to drive spatially explicit modelling of the uptake of electrified transport and heating; and temporally explicit modelling of the electricity demand of these technologies for a local geography. The methodology is demonstrated on a model of a real electricity distribution network that serves households within the local geography and is used as the basis to examine the impacts of the varying demand scenarios on network infrastructure. An unbalanced OPF formulation that enables smart EV charging and V2G also forms part of the methodology and is used to investigate the impact of these future demand scenarios on the potential of flexibility in electricity demand.

The value of the approach stems from the ability to postulate what electric heating and EV charging demand would be for a particular local area under particular future scenarios. The approach then has the capability to assess whether a particular electricity distribution network could accommodate those demands and the extent to which optimal utilisation of smart charging can avoid or defer network reinforcement. Therefore, the presented method can be used to inform on the impacts of decision making in this space.

In summary, the research work of this thesis has evidenced that electrification of heat and transport enables more efficient use of primary energy than use of fossil fuels. However, as a consequence, the electricity demand will significantly increase, challenging existing electricity system infrastructure.On the basis of the reported findings, it is concluded that energy demand futures with policies focused on energy demand reduction using the *Avoid-Shift-Improve* framework [269] are shown to mitigate the need for reinforcement of electricity networks (for the case study considered a reduction in evening transformer loading of up to 16% can be achieved). However, flexibility in electricity demand contributes a larger difference to a network's ability to host electrified heat and transport than relying solely on energy demand reduction. Energy futures that combine policies that pursue energy demand reduction and simultaneously enable electricity system flexibility present the greatest benefits, both to the mitigation of reinforcement and to system operability in the context of growing penetrations of variable renewable generation (for the case studies considered a reduction in evening transformer loading of up to 69% can be achieved). Despite these benefits, it has been shown that electricity demand is still likely to increase significantly relative to the current baseline. Therefore, widespread network reinforcement of the electricity system will still be necessary in the transition to net-zero and, accordingly, urgent investment is required to support the realisation of the UK's legally-binding climate goals.

What impact does both the electrification of heat and transport have on local electricity systems and flexibility in network planning?

The thesis has answered a series of sub-questions that collectively provide a contribution towards answering this broader overarching research question. In this regard, taking a wider view on the thesis in its entirety, socio-technical and socio-spatial dimensions should be taken into consideration in future decision making to facilitate a 'just transition'. This work has evidenced the influence these dimensions may have from the technical perspective of the DNO and external stakeholders. This has been captured across the thesis with consideration for both temporal and spatial impacts at different stages of the research investigation. This extends to cooperation between local authorities, policy makers and DNOs if infrastructure is to be optimally developed in line with the evolving needs of society.

The presented work has focused on the uptake of electrified heat and transport in terms of HPs and EVs, with justification evidenced through carrying out detailed background research on the technological options to enable decarbonisation in these sectors. Key challenges begin to emerge in a practical setting that this work has supported, e.g. consumers who connect an EV or HP first, and vice-versa, may see an application to connect the other technology at a later date rejected due to capacity constraints or network limitation. This interplay between different accessibility requirements of consumers will have an impact on the pace of decarbonisation in each sector e.g. early adopters of EVs may see their ability to switch to low carbon heating limited by the network and vice versa. The extent of this challenge is only obtainable by carrying out detailed integrated impact assessments that the developed methodologies are able to support. This will then allow for the development of solutions to manage investment prioritisation for different stakeholders and provide an indication of when such investments may be necessary.

The role of policy targeted at the local-level will be instrumental in supporting the combined electrification of residential heat and transport on distribution networks and mitigating the impact on distribution network infrastructure. Policy to support demand reductions and improve human well-being will be necessary as will policy aimed at enabling the use of 'smart' flexible technologies to defer network reinforcement. However, whilst such technologies are expected to be valuable from a network planning perspective in the transition to net zero, significant amounts of reinforcement will be unavoidable across the distribution network as a result of electrifying both heat and transport. Beyond planning and net zero, these technologies will have a role in operation of the distribution networks from enabling resiliency as a service to local energy system management.

This thesis proposes several methods to enable high-resolution place-based research with respect to the decarbonisation of heat and transport and electricity system infrastructure. The presented methods are distinct from existing methodologies that are concerned with the electrification of heat and transport technologies in the distribution network planning domain. In that they have been developed to be 'agnostic' for use with different network datasets and publicly available metadata. The place-based nature of their application allows for consideration of the socio-spatial and socio-technical indicators that inform LCT demand consumption, where supporting analysis is capable of reducing the uncertainty surrounding the impact LCTs of different types will have on existing infrastructure in different locations. Such insights will help to inform network investment decision making and shape policy within this space.

6.2 Future Research

From the research presented in this thesis and with respect to the contributions made, several avenues for further research have been identified.

As the developed method in Chapter 3 takes a conservative approach to EV modelling from the perspective of the DNO, modelling at-home charging only by following the government-lead assumption that the majority of charging in the UK will take place at home [202], given that it is reasonable to expect they will have to deal with scenarios where all vehicle chargers in a given area are home-chargers rather than work/public-chargers or a combination of (particularly in purely residential areas where HPs are more likely to be installed). There would be scope to evolve this approach to account for work/public-chargers in the form of fast charging stations or charging hubs. Although these are more likely to attract specific attention from DNOs and would also fall within the remit of the local authority planning system. Given that there would be scope for DNOs to anticipate their connection and to influence their location to ensure compatibility with network capacity this could be captured in the modelling.

Also, due to the uncertainty and complexity associated with the decarbonisation of domestic heating, impacts on electricity network infrastructure and how consumers interact with heating systems in different locations is expected to vary significantly particularly in that different areas may take radically different decarbonisation pathways. Whilst this work has in-part captured the impact of place-based localisation and diversity in relation to HPs there is scope to conduct further research to account for different heating technologies and the respective impacts on network infrastructure. A more holistic approach could be adopted that also considers the interplay across direct and indirect electricity use for transport. With this, there is a need to demonstrate and quantify how further exploration of the links between socio-technical and social-spatial indicators, LCTs and key infrastructure can support stakeholders in tackling fuel poverty and to ascertain the wider 'just transition' policy implications of alternative decarbonisation pathways. This should involve a multi-disciplinary collaborative effort with different stakeholders from various research domains.

Expanding the methodology in Chapter 4 to include local weather-sensitive solar PV would also allow for insight into the interactions between different LCTs and the accompanying network management implications. This would allow for detailed integrated analysis of both solar PV and EV impacts which will be a dominant LCT mix in areas where alternative heating solutions to electrification are deployed. There is scope to investigate this dynamic under alternative future scenarios e.g. during summer with increased amounts of home working.

There is also a growing need to model both HV – often referred to as medium voltage (MV) – and LV networks to capture interactions between the voltage tiers and voltage fluctuations [249], [315], [316]. The LV network modelling capability and dataset fusion techniques developed in Chapter 4 should be integrated with an EHV/HV modelling capability. This will enable the development of entire distribution network models from GSPs to LV for specific areas. These models would support broader research within the heating and transport space, allowing for extension beyond the domestic sector and enabling the development of digital-twins as monitored data becomes more readily available through digitalisation across RIIO-ED2.

In Chapter 5, plausible future reductions in heating demand are used to capture improvements in building fabric and the evolution of heating technologies. This was required as the assumptions used for heating in the CREDS PLEFs are relatively vague which limited the derivation of quantitative demand reduction values. Noting that there are contradicting assumptions/evidence in the existing literature in this respect, there is significant scope for research surrounding derivation of future heating demand and the role of policies aimed at demand reduction, and energy efficiency improvement.

Finally, while Chapter 5 focused on the flexibility potential of EVs, the flexibilities offered by heating technologies should be further explored. This could include the use of thermal storage and innovative phase change materials for time shifting heating demand, but also changes in consumer heating behaviour and habits e.g. pre-heating and alternative actions to improve thermal comfort. With this, the interplay between heat and transport flexibility can be explored and the potential benefits quantified.

Appendix A

Mapping of SIMD to Secondary Transformers: Scaled Figure

Figure A.1 highlights the SIMD-secondary transformer mapping process as in Figure 3.6.

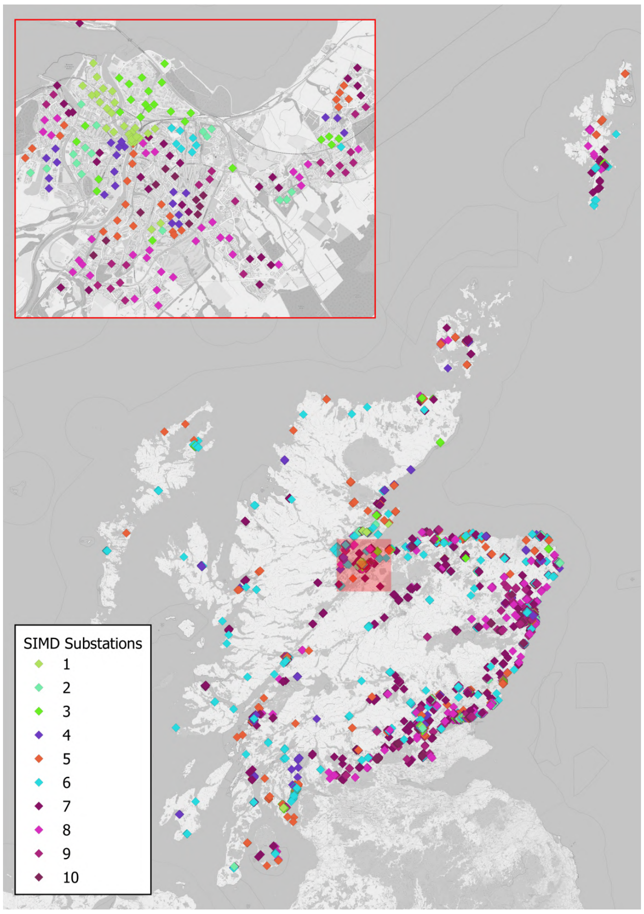

Figure A.1. Mapping of SIMD deciles to secondary transformers based on geographic location.

Appendix B

Cable Data for Network Models

Figure B.1 demonstrates that each cable has an associated linecode. This linecode is used to assign line impedance values and current ratings to cables within the OpenDSS electrical model.

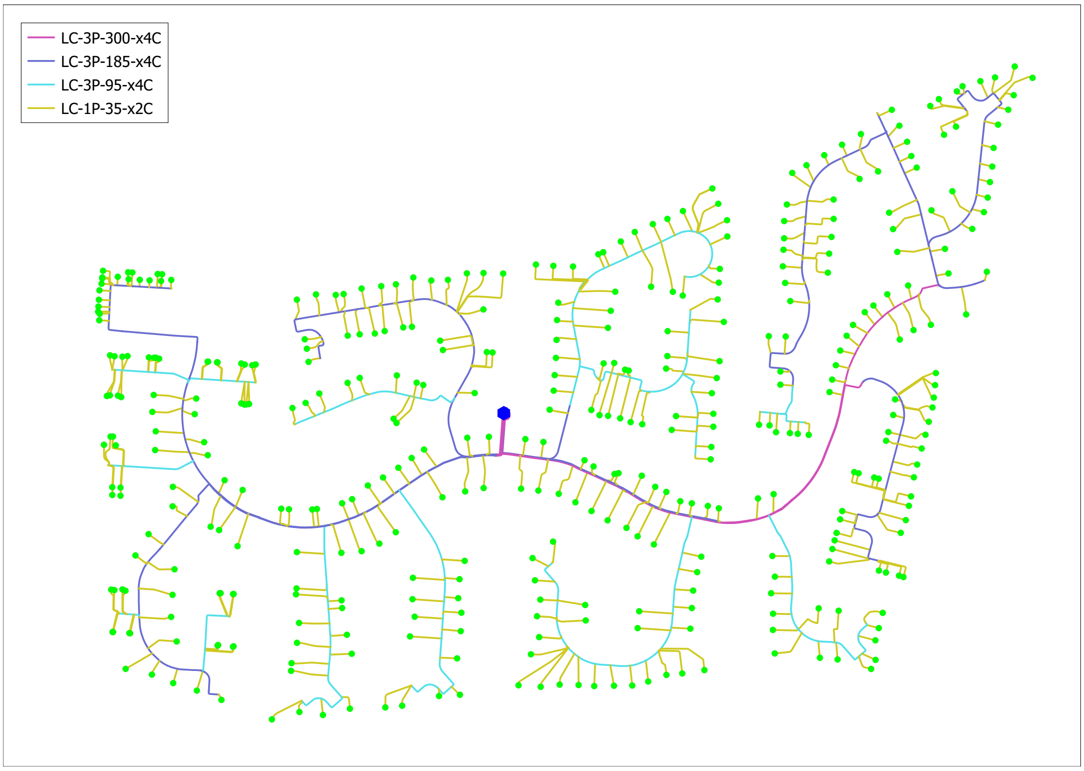

Figure B.1. Example network (network 2) showing the linecode associated with each cable.

Table B.1 provides a summary of the cable data used in this work which has been consolidated from [35]–[37]. In Table B.1, R1 represents the resistance per unit length of the cable for phase conductor, X1 represents the reactance per unit length of the cable for phase conductors, R0 represents the zero sequence resistance per unit length of the cable, X0 represents the zero sequence reactance per unit length of the cable, C1 represents the capacitance per unit length of the cable for phase conductors and C0 represents the zero sequence capacitance per unit length of the cable.

Table B.1. Summary of cable data [35]–[37]

Linecode	Voltage (kV)	in^2	mm^2	Phases	Core	R1	X1	R0	X0	C1	C0	Type	I_{max} (A)
LC-1P-0.0145-x2C	0.415	0.0145	9.35482	1	2	1.903	0.09	0.625	0.109	0.35	0.76	Service	70
LC-1P-0.0225-x2C	0.415	0.0225	14.5161	1	2	1.257	0.085	0.805	0.092	0.38	0.604	Service	100
LC-1P-16-x2C	0.415	0.0248	16	1	2	1.15	0.088	1.489	0.091	0.35	0.45	Service	120
LC-1P-25-x2C	0.415	0.03875	25	1	2	0.727	0.092	0.69	0.078	0.38	0.35	Service	135
LC-1P-35-x2C	0.415	0.05425	35	1	2	0.868	0.077	0.958	0.079	0.42	0.537	Service	140
LC-1P-4-x2C	0.415	0.0062	4	1	2	4.61	0.091	0.69	0.079	0.27	0.612	Service	53
LC-3P-185-x3C	0.415	0.28675	185	3	3	0.166	0.074	0.664	0.113	0.699	0.699	Feed	305
LC-3P-95-x3C	0.415	0.14725	95	3	3	0.322	0.069	1.201	0.096	0.699	0.699	Feed	195
LC-3P-0.04-x4C	0.415	0.04	25.8064	3	4	0.708	0.079	2.319	0.094	0.358	0.358	Feed	115
LC-3P-0.06-x4C	0.415	0.06	38.7096	3	4	0.469	0.075	1.582	0.09	0.399	0.399	Feed	150
LC-3P-0.1-x4C	0.415	0.1	64.516	3	4	0.274	0.073	0.958	0.079	0.537	0.537	Feed	200
LC-3P-0.15-x4C	0.415	0.15	96.774	3	4	0.195	0.07	0.69	0.079	0.612	0.612	Feed	225
LC-3P-0.25-x4C	0.415	0.25	161.29	3	4	0.124	0.069	0.442	0.078	0.629	0.629	Feed	355
LC-3P-0.3-x4C	0.415	0.3	193.548	3	4	0.106	0.068	0.379	0.077	0.699	0.699	Feed	400
LC-3P-16-x4C	0.415	0.0248	16	3	4	1.149	0.08	4.26	0.092	0.35	0.35	Feed	95
LC-3P-185-x4C	0.415	0.28675	185	3	4	0.166	0.073	0.412	0.094	0.699	0.699	Feed	305
LC-3P-25-x4C	0.415	0.03875	25	3	4	1.2	0.079	1.3	0.079	0.37	0.37	Feed	135
LC-3P-300-x4C	0.415	0.465	300	3	4	0.102	0.072	0.291	0.087	0.791	0.791	Feed	430
LC-3P-70-x4C	0.415	0.1085	70	3	4	0.446	0.071	2.54	0.092	0.537	0.537	Feed	205
LC-3P-95-x4C	0.415	0.14725	95	3	4	0.322	0.074	0.805	0.092	0.604	0.604	Feed	235
LC-3P-0.06-x5C	0.415	0.06	38.7096	3	5	0.469	0.075	1.581	0.091	0.3	0.3	Feed	225
LC-3P-300-x3C	0.415	0.465	300	3	3	0.102	0.068	0.384	0.086	0.791	0.791	Feed	385

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